Xcel Energy℠

July 16, 2021

Ms. Melanie Sandoval, Records Bureau Chief
New Mexico Public Regulation Commission
P.O. Box 1269
Santa Fe, NM 87504-1269

Re: Case No. 21-00169-UT *In the Matter of Southwestern Public Service Company's 2021 Integrated Resource Plan*

Dear Ms. Sandoval:

Pursuant to Section 9(A) of NMAC 17.7.3, Southwestern Public Service Company ("SPS") hereby files with the New Mexico Public Regulation Commission ("Commission"), its 2021 New Mexico Integrated Resource Plan ("IRP") for the period 2022 through 2041.

A copy of this filing is being provided electronically to the Commission's Utility Division Staff, interveners in SPS's most recent general rate case, and participants in SPS's most recent renewable energy, energy efficiency, and IRP proceedings.

SPS is also providing a copy of the filing on the Xcel Energy IRP website, https://www.xcelenergy.com/company/rates_and_regulations/resource_plans.

If you have any questions, please contact me at (806) 378-2115 or Linda Hudgins, Case Specialist II at (806) 378-2709.

Yours very truly,

<u>/s/ Mario Contreras</u>
Mario Contreras,
Manager Rate Cases

Enclosures

2021
Integrated Resource Plan
Filed in Compliance with 17.7.3 NMAC

Southwestern Public Service Company

July 16, 2021

Xcel Energy℠
SOUTHWESTERN PUBLIC SERVICE

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.

Table of Contents

List of Tables

List of Figures

List of Appendices

Glossary of Acronyms and Defined Terms

Acronym/Defined Term	**Meaning**
2021 IRP	Integrated Resource Plan, filed July 16, 2021
Action Plan	IRP Implementation During the First Four Years of the IRP
Action Plan Period	2021 IRP implementation from 2022-2025
ATB	Annual Technology Baseline
BESS	Battery Energy Storage System
CC	Combined Cycle
CO_2	carbon dioxide
Commission	New Mexico Public Regulation Commission
CTG	Combustion Turbine Generator
DSM	Demand-Side Management
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EOY	End of Year
EUEA	Efficiency Use of Energy Act
FOM	Fixed Operations and Maintenance
GCP	Combined Real Gross County Product
GWh	gigawatt-hour
HRSG	Heat Recovery Steam Generator
ICO	Interruptible Credit Option
IRP	Integrated Resource Plan

Acronym/Defined Term	**Meaning**
IRP Rule	17.7.3 NMAC
ISO	independent system operator
ITC	Investment Tax Credit
kW	kilowatt
kWh	kilowatt-hour
L&R	Loads and Resources
LED	Light Emitting Diode
LM	Load Management
LOLE	Loss of Load Expectation
LRE	Load Responsible Entity
MMBtu	Million British Thermal Unit
MW	megawatt
MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
OATT	Open Access Transmission Tariff
O&M	Operations and Maintenance
Planning Period	2022-2041 Planning Period

Acronym/Defined Term	Meaning
Planning Reserve	available capacity above the projected peak demand
PPA	Purchased Power Agreement
PRM	Planning Reserve Margin
PTC	Production Tax Credit
PV	photovoltaic
QF	Qualifying Facility
RFI	Request for Information
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SPS	Southwestern Public Service Company, a New Mexico corporation
Staff	Utility Division Staff of the Commission
STG	Steam Turbine Generator
TCEQ	Texas Commission on Environmental Quality
Tolk Analysis	analysis evaluating the economically optimal retirement date of the Tolk Units
TOU	Time of Use
VOM	Variable Operations and Maintenance
Xcel Energy	Xcel Energy Inc.

Executive Summary

SPS presents its 2021 Integrated Resource Plan ("2021 IRP") identifying the most cost-effective portfolio of resources over the 20-year Planning Period (2022 – 2041). For more than a decade, SPS has strived to serve its customers with a cleaner mix of generating resources and with an energy grid that is more reliable and secure - all while keeping customer energy bills low. SPS continues to deliver on this goal, successfully adding an additional 1,230 megawatts ("MW") of low-cost wind generation since the filing of the 2018 IRP. In addition, SPS is well positioned to comply with New Mexico's Renewable Portfolio Standards ("RPS") and the State's carbon emission reduction goals. In SPS's most recent RPS filing (New Mexico Case No. 21-00172-UT), SPS proposed early compliance with the RPS's 2025 goal to supply no less than 40% of SPS's New Mexico retail energy sales by renewable energy, and last year, SPS's carbon emissions were reduced 55% when compared with 2005 levels.

The highlighted changes below demonstrate that SPS's 2021 IRP continues to support the company's commitment to provide clean, reliable and affordable energy.

Future Operation of SPS's Coal Generating Units

SPS's existing coal generating units have, or are planned to, undergo substantial operational changes since SPS's filed its last IRP in 2018. Beginning 2021, the Tolk Generating Units located in Texas are economically dispatched during the high load summer months, and to conserve limited groundwater are shut down in the eight off-peak months (unless called upon in urgent need conditions). SPS's Tolk Analysis, which was filed in advance of this IRP, continues to support seasonal operation of the Tolk Units until a 2032 retirement date. Additionally, per an agreed order with the Texas Commission on Environmental Quality ("TCEQ"), SPS's other coal-fired plant, the

Harrington Generating Station located in Texas, is planned to be converted to operate exclusively on natural gas by the end of 2024. Both the Tolk and Harrington Generating Stations are scheduled to retire within the 20-year IRP planning period.

Aging Gas Steam Resources

Several of SPS-owned gas steam generating units are at the end of their useful life. During the 4-year Action Plan[1], over 650 MW of gas steam generation is scheduled to retire and within the Planning Period, SPS's entire 1.6 GW portfolio of gas steam generating units are scheduled to retire.

Economic Renewable Energy Resources

SPS's most cost-effective portfolio of resources and alternative portfolios support a continued transition to a more renewable-heavy portfolio of generating resources, especially as SPS's existing coal and aging gas steam resources are scheduled to retire. Despite scheduled retirements, during the Action Period, SPS has sufficient resources to meet its reliability and regulatory requirements, therefore is well positioned to acquire new economic energy resources only when they are most likely to economically benefit SPS's customers.

Emerging Technologies

The continued transition to a more renewable heavy portfolio of resources will also necessitate a need for firm peaking and load-following resources to provide reliability and energy while intermittent resources, such as wind and solar, are not available. Currently, natural gas combustion turbine generators ("CTG") are the most economical technology to provide critical system reliability needs. However, to meet New Mexico's 2045 carbon-free goal, natural gas CTGs may be required to use carbon-free hydrogen as a fuel source, or CTGs may ultimately be replaced by emerging

---

[1] IRP Implementation During the First Four Years of the IRP

technologies, such as battery energy storage systems ("BESS"). By preserving the capacity and energy benefits of the Tolk and Harrington Generating Stations under current planning, SPS's most cost-effective portfolio of resources does not include any new carbon-emitting resources until 2031, therefore, providing SPS time to re-evaluate emerging technologies in future IRPs.

Section 1. INTRODUCTION

SPS, a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), presents its 2021 integrated resource plan ("2021 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 2021 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 2022-2041 Planning Period ("Planning Period"); and (ii) provides an Action Plan discussing 2021 IRP implementation from 2022-2025 ("Action Plan Period").

Per the uncontested comprehensive stipulation in SPS's New Mexico Base Rate Case No. 19-00170-UT, SPS's 2021 IRP includes an updated "Tolk Analysis" evaluating the economically optimal retirement date of the Tolk Units. The Tolk Analysis is included in its entirety in Appendix H and was filed with the Commission in advance of the IRP on June 30, 2021.

SPS's 2021 IRP was developed by considering studies, forecasts, regulatory predictions, and information exchanged through a series of technical conferences and 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 applicable regulatory, and operational obligations and both short- and long-term least-cost impacts to customers, while balancing the ability to deliver the expected level of service to customers while meeting applicable regulatory and operational obligations. The goal of SPS's 2021 IRP was to develop a reliable, robust, cost-effective, and environmentally-focused generation expansion plan.

Many factors may impact this IRP and could potentially require updates to the Action Plan and will be the subject of future IRPs. These factors include: (i) changes to the operation of SPS's existing coal-fired generating units; (ii) changes to, or the extension of, renewable tax credits; (iii) uncertainty in the cost and schedule of interconnecting new generation within SPS's footprint; and (iv) potential technological and economic advances in emerging technologies. Each of these factors are discussed in more detail in Section 7.

Most importantly, the resource plan is presented based on the best information available at this time and with recognition that SPS will have to be flexible in resource plan execution over the Action Plan and Planning Period as new information becomes available and in response to the inherent uncertainty of long-term forecasting and resource planning. SPS will continue to actively monitor developments in these areas. However, as presented, SPS's 2021 IRP provides a well-rounded resource portfolio that addresses customer cost impacts, environmental impacts, critical reliability needs in localized areas of SPS, operational issues, and complies with applicable regulatory requirements.

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, and reserve margin/reliability requirements, (iii) Section 4 provides SPS's current load forecast; (iv) Section 5 presents SPS's Loads and Resources ("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

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 and 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 resources 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 N for a table indicating where each of the rule requirements is met in this filing.

In addition, the uncontested comprehensive stipulation in New Mexico Case No. 19-00170-UT required SPS's 2021 IRP to include a robust analysis of Tolk abandonment and economical potential means of replacement by June 2021 (the "Tolk Analysis"). The Tolk Analysis is included in its entirety in Appendix H and was filed with the Commission in advance of the IRP on June 30, 2021.

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), its third IRP on July 16, 2015 (Case No. 15-00217-UT), and its fourth IRP on July 16, 2018 (Case No. 18-00215-UT); all of SPS's IRPs were accepted by the Commission. SPS's 2021 IRP includes all required components of the IRP Rule.

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

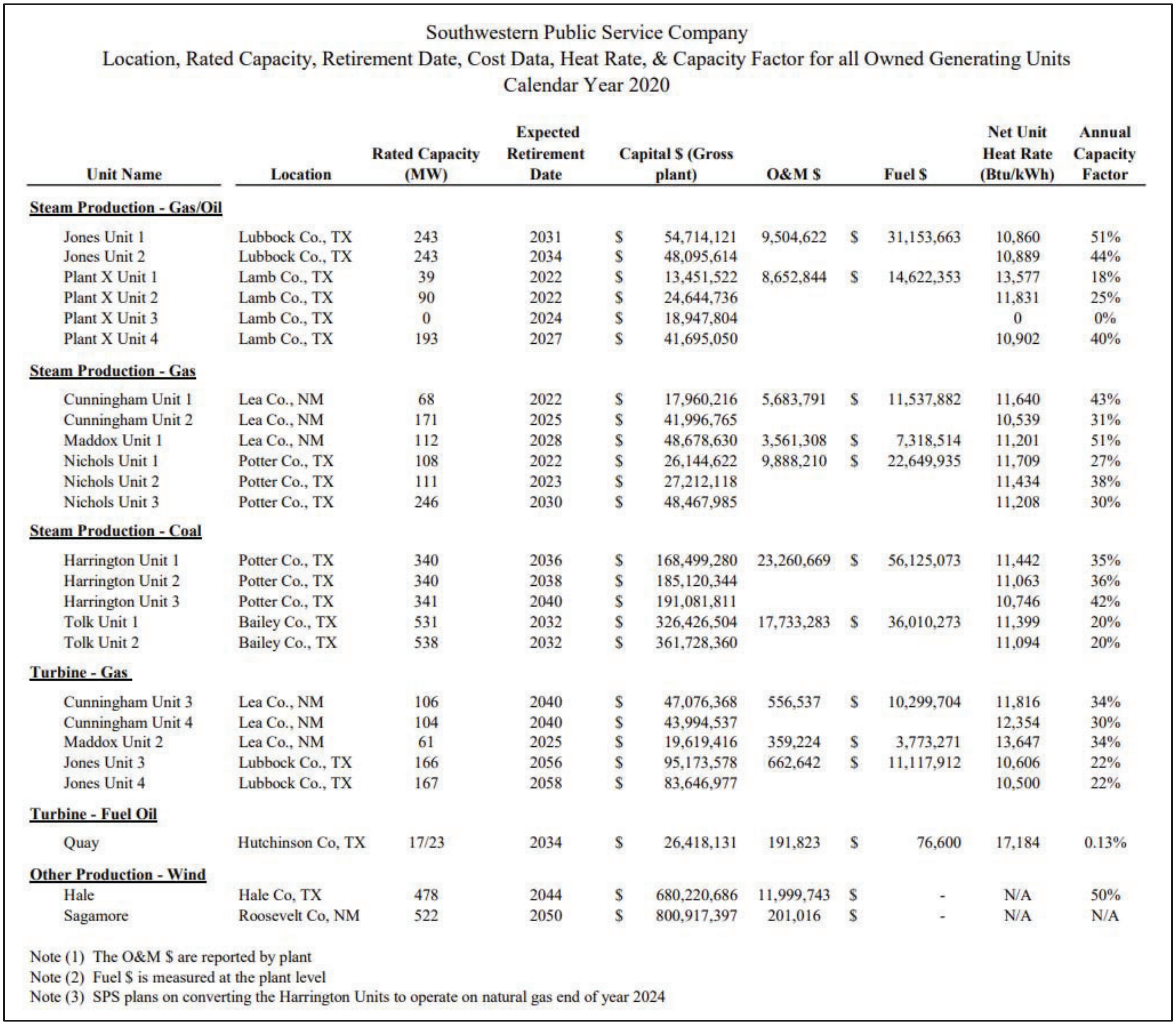
3.01 - SPS-Owned Resources

SPS owns supply-side thermal generation resources, located in both New Mexico and Texas, which serve its entire system. SPS's supply-side thermal resources had a 2020 summer generation capacity of 4,335 MW and were comprised of a mix of coal-fired, gas steam, and simple-cycle CTG units. As shown in Table 3-1 (next page), the Tolk and Harrington coal-fired generating units provided nearly half of the 2020 summer peak capacity; gas steam units totaled approximately 1.6 GW; and simple-cycle CTG units totaled over 600 MW.

SPS also owns and operates two wind generating facilities. The 478 MW Hale Wind generating facility (Hale County, Texas) was placed in-service in June 2019, and the 522 MW Sagamore Wind generating facility (Roosevelt County, New Mexico) was placed in-service in December 2020.

The names, fuel types, locations, rated capacities (MW), expected retirement dates, capital costs (gross plant balance), fixed and variable operation and maintenance costs ("FOM" and "VOM"), fuel costs, heat rates (Btu/kWh), and annual capacity factors for calendar year 2020 are provided in Table 3-1 (next page).

Table 3-1: Location, Rated Capacity, Retirement Date, Cost Data, Heat Rate, and Capacity Factor for all Generating Units - Calendar Year 2020



Southwestern Public Service Company
Location, Rated Capacity, Retirement Date, Cost Data, Heat Rate, & Capacity Factor for all Owned Generating Units
Calendar Year 2020

Unit Name	Location	Rated Capacity (MW)	Expected Retirement Date	Capital $ (Gross plant)	O&M $	Fuel $	Net Unit Heat Rate (Btu/kWh)	Annual Capacity Factor
Steam Production - Gas/Oil								
Jones Unit 1	Lubbock Co., TX	243	2031	$ 54,714,121	9,504,622	$ 31,153,663	10,860	51%
Jones Unit 2	Lubbock Co., TX	243	2034	$ 48,095,614			10,889	44%
Plant X Unit 1	Lamb Co., TX	39	2022	$ 13,451,522	8,652,844	$ 14,622,353	13,577	18%
Plant X Unit 2	Lamb Co., TX	90	2022	$ 24,644,736			11,831	25%
Plant X Unit 3	Lamb Co., TX	0	2024	$ 18,947,804			0	0%
Plant X Unit 4	Lamb Co., TX	193	2027	$ 41,695,050			10,902	40%
Steam Production - Gas								
Cunningham Unit 1	Lea Co., NM	68	2022	$ 17,960,216	5,683,791	$ 11,537,882	11,640	43%
Cunningham Unit 2	Lea Co., NM	171	2025	$ 41,996,765			10,539	31%
Maddox Unit 1	Lea Co., NM	112	2028	$ 48,678,630	3,561,308	$ 7,318,514	11,201	51%
Nichols Unit 1	Potter Co., TX	108	2022	$ 26,144,622	9,888,210	$ 22,649,935	11,709	27%
Nichols Unit 2	Potter Co., TX	111	2023	$ 27,212,118			11,434	38%
Nichols Unit 3	Potter Co., TX	246	2030	$ 48,467,985			11,208	30%
Steam Production - Coal								
Harrington Unit 1	Potter Co., TX	340	2036	$ 168,499,280	23,260,669	$ 56,125,073	11,442	35%
Harrington Unit 2	Potter Co., TX	340	2038	$ 185,120,344			11,063	36%
Harrington Unit 3	Potter Co., TX	341	2040	$ 191,081,811			10,746	42%
Tolk Unit 1	Bailey Co., TX	531	2032	$ 326,426,504	17,733,283	$ 36,010,273	11,399	20%
Tolk Unit 2	Bailey Co., TX	538	2032	$ 361,728,360			11,094	20%
Turbine - Gas								
Cunningham Unit 3	Lea Co., NM	106	2040	$ 47,076,368	556,537	$ 10,299,704	11,816	34%
Cunningham Unit 4	Lea Co., NM	104	2040	$ 43,994,537			12,354	30%
Maddox Unit 2	Lea Co., NM	61	2025	$ 19,619,416	359,224	$ 3,773,271	13,647	34%
Jones Unit 3	Lubbock Co., TX	166	2056	$ 95,173,578	662,642	$ 11,117,912	10,606	22%
Jones Unit 4	Lubbock Co., TX	167	2058	$ 83,646,977			10,500	22%
Turbine - Fuel Oil								
Quay	Hutchinson Co, TX	17/23	2034	$ 26,418,131	191,823	$ 76,600	17,184	0.13%
Other Production - Wind								
Hale	Hale Co, TX	478	2044	$ 680,220,686	11,999,743	$ -	N/A	50%
Sagamore	Roosevelt Co, NM	522	2050	$ 800,917,397	201,016	$ -	N/A	N/A

Note (1) The O&M $ are reported by plant
Note (2) Fuel $ is measured at the plant level
Note (3) SPS plans on converting the Harrington Units to operate on natural gas end of year 2024

3.02 - SPS-Purchased Power

In addition to SPS's owned generation, SPS currently has long-term purchased power agreements ("PPA") totaling 2,444 MW of nameplate capacity and associated energy. SPS purchases the energy output from renewable intermittent generation consisting of 1,450 MW of wind and 192 MW_{AC} of solar. These resources serve SPS's entire system. Table 3-2 lists the nameplate 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	Nameplate Capacity (MW)	Commercial Operation Date	Expiration Date
Sid Richardson Carbon Ltd. Gas Facility	5	2001	2021[2]
Blackhawk Station Simple Cycle Combustion Turbines	223	1999	2024[3]
Lea Power Partners Combined Cycle	574	2008	2033
Subtotal	**802**		
Caprock Wind	80	2004	2024
San Juan (Padoma) Wind	120	2005	2025
Wildorado Wind	161	2007	2027
Spinning Spur Wind	161	2012	2027
Mammoth Wind	199	2014	2034
Palo Duro Wind	249	2014	2034
Roosevelt Wind	250	2015	2035
Lorenzo Wind (Bonita I)	80	2018	2048
Wildcat Wind (Bonita II)	150	2018	2048
Subtotal	**1,450**		
Sun Edison Solar	50	2011	2031
Chaves Solar	70	2016	2041
Roswell Solar	70	2016	2041
SoCore Clovis 1 LLC[4]	1.98	2021	2041
Subtotal	**192**		
Total Firm (PPAs)	**2,444**		

Figure 3F.1 below provides a regional map of the SPS generation fleet (owned and PPAs). A regional map of SPS's transmission system is also provided in Appendix O.

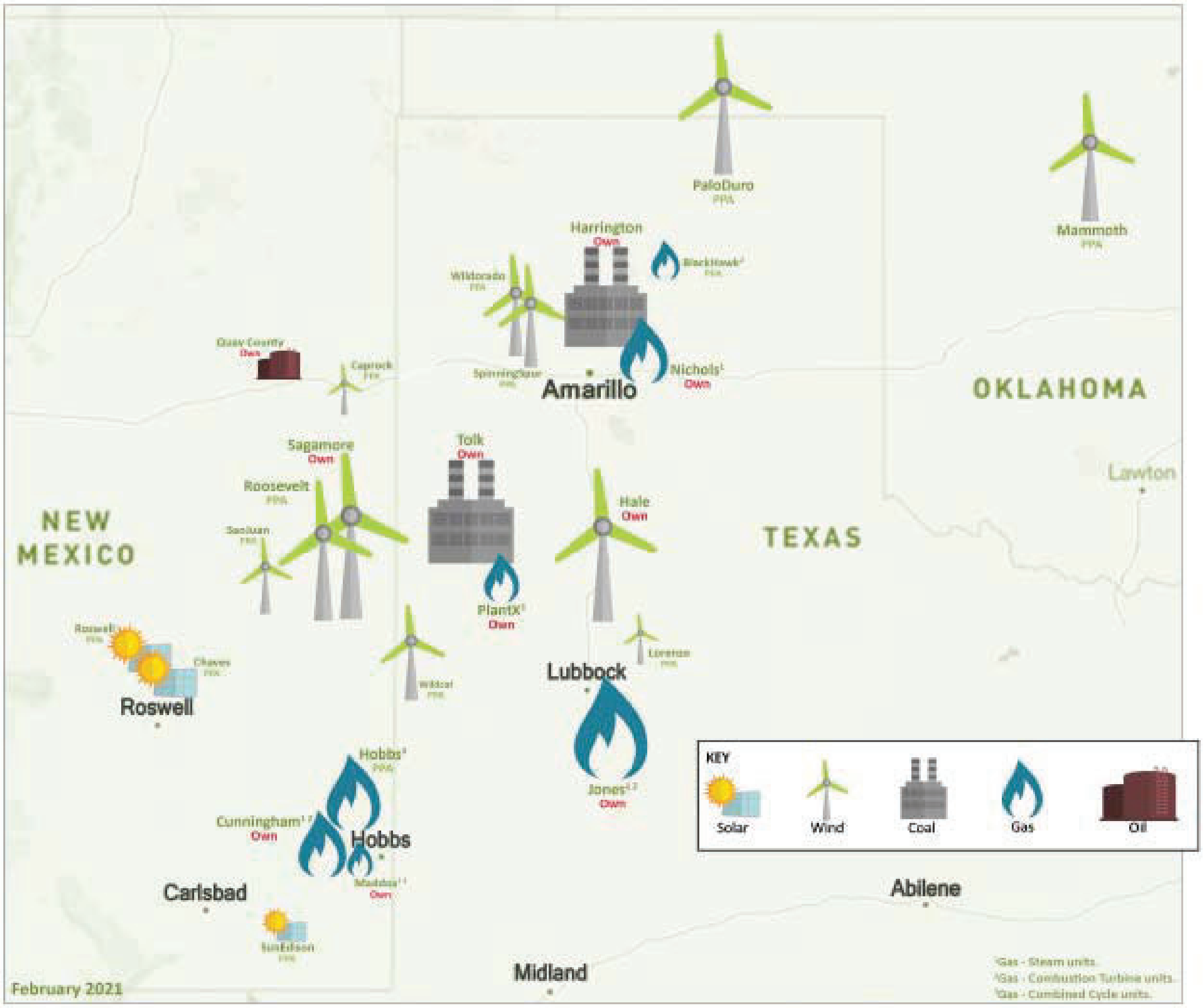
---

[2] The PPA between SPS and Tokai Carbon CB Ltd. (Sid Richardson) is scheduled to terminate August 1, 2021, which is prior to the end of the Southwest Power Pool Summer Season (June 1 – September 31).

[3] The PPA between SPS and Borger Energy Associates (Blackhawk Station) is scheduled to terminate on June 12, 2024, which is prior to the expected summer peak .

[4] The SoCore Facility is utilized for SPS's Voluntary Renewable Energy Program in New Mexico, referred to as Solar*Connect.

Figure 3F.1: SPS Existing Generation Fleet (Owned and PPAs)



3.03 – SPS Qualifying Facilities

In addition to SPS's owned and long-term PPAs, SPS also purchases energy from eight Qualifying Facilities ("QF"), with a total nameplate capacity of 111 MW, that are put to SPS under the Public Utility Regulatory Policy Act of 1978. Per SPS's New Mexico Rate No. 4 or the Texas Electric Tariff Sheet No. IV-117 (Rev. No. 4) a QF that chooses to sell energy to SPS under these Rates/Tariffs, must execute the standard Purchase Agreement. See Table 3-3 below for a list of SPS QF Wind facilities.

Table 3-3: QF Wind

QF Wind	Nameplate Capacity (MW)	Commercial Operation Date
Ralls Wind	10	07/20/2011
Cirrus Wind	61.2	12/12/2012
Pantex Wind	11.5	06/20/2014
Pleasant Hills Wind	19.8	06/04/2014
Aeolus Wind	3	04/05/2004
National Windmill	0.66	12/07/2005
West Texas A&M	3.51	11/11/2013
Mesalands Community College	1.5	07/08/2015

In addition, SPS historic cost (calendar year 2020) information regarding each of the long-term PPAs and QFs is provided in Appendix A.

3.04 - Existing & Approved Energy Storage Resources

Currently, SPS has no existing or approved energy storage resources.

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

Currently, SPS has no new generating resources under construction or scheduled for the Planning Period.

3.06 - Wheeling Agreements

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

3.07 - 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."[5] 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."[6] SPS offers DSM resources in both New Mexico and Texas in accordance with state-specific rules and laws.[7]

New Mexico DSM

SPS must annually report its achieved levels for the previous calendar year and receive approval of its forward looking plans every three years to continue towards its statutory goals. SPS's 2019 EE Triennial Plan approving Plan Years 2020-2022 was approved in Case No. 19-00140-UT on February 19, 2020.[8] SPS will continue its approved Triennial Plan through Plan Year 2021. In

---

[5] Rule 17.7.3.7.D NMAC.

[6] Rule `7.7.3.7.I NMAC.

[7] DSM costs are directly assigned by jurisdiction.

[8] *In the Matter of Southwestern Public Service Company's Triennial Energy Efficiency Plan Application Requesting Approval of: (1) SPS's 2020-2022 Energy Efficiency Plan and Associated Programs; (2) A Financial Incentive for Plan Year 2020; (3) Recovery of the Costs Associated with a potential Energy Efficiency Study over a Two-Year Time Period; and (4) Continuation of SPS's Energy Efficiency Tariff Rider to Recover Its Annual Program Costs and Incentives,* Case No. 19-00140-UT, Final Order Approving Certification of Stipulation (Feb 19, 2020).

accordance with the Final Order in Case No. 19-00140-UT, SPS refiled its Plan Year 2022 portfolio and proposed goals on July 15, 2021. Previous plans were approved for calendar years 2011 – 2019 in Case Nos. 11-00400-UT, 13-00286-UT, 15-00119-UT, 16-00110-UT, 17-00159-UT, 18-00139-UT, and 19-00140-UT, respectively. Table 3-4 below describes SPS's EE achievements under the EUEA.

Table 3-4: New Mexico EE Achievements for Plan Years 2013-2020

Year	Customer kW[9] Saved	Customer kWh Saved
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
2018	7,539	42,841,455
2019	9,415	39,420,766
2020	7,404	46,980,168

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).

<u>Residential Segment</u>:

- Residential Energy Feedback (EE) – This program is designed to quantify the effects of informational feedback on energy consumption in approximately 15,000 residential households, consistent with the Commission's Final Order in Case No. 09-00352-UT.[10] This program provides educational materials and communication strategies to create a change in energy usage behavior. The purpose of the program is to measure when, how, and why customers change their behavior when provided with feedback on their energy using habits.

- Residential Cooling (EE) – This program offers rebates for the purchase of high efficiency evaporative cooling, air conditioning, and heat pump units. Rebates for evaporative coolers are paid for purchase of new units with an efficiency greater than 85%, installed in new or existing construction, regardless of whether or not the customer is replacing an existing unit.

---

[9] kilowatt

[10] Case No. 09-00352-UT, *In the Matter of Southwestern Public Service Company's Application for Approval of its 2010/2011 Energy Efficiency and Load Management Plan and Associated Programs, Requested Variances, and Cost Recovery Tariff Rider,* Final Order Adopting Certification of Stipulation (Mar. 15, 2011).

Air conditioning and heat pump rebates are paid to registered contractors who perform a quality installation in new and existing homes.

- Home Energy Services (EE) – Under this program, SPS provides incentives for the installation of a wide range of energy savings measures that reduce customer energy costs. The incentives are paid to energy efficiency service providers on the basis of deemed (*i.e.,* pre-determined) energy savings. The program, which also includes a Low-Income offering, includes attic insulation, air infiltration reduction, refrigerators (for low-income participants) and duct leakage repairs. The program is delivered via third-party providers interacting directly with customers to perform the home improvements. Additionally, Income-qualified customers, will receive an offer through mail informing them of their eligibility to receive a free Energy Savings Kit. A customer is qualified by being identified as receiving energy assistance through federal Low-Income Home Energy Assistance Program. If the customer chooses to receive a kit, they will send their response to the third-party implementer. Customers will receive a kit within six to eight weeks.

- Home Lighting (EE) – This program provides incentives for customers to purchase energy efficient LEDs[11] through participating retailers. Participating retailers may include home improvement, mass merchandisers, and hardware store locations. Customers will be able to recycle used compact fluorescent lights at select retail partner locations.

- Heat Pump Water Heaters (EE) – This program provides rebates for the purchase of high-efficiency electric heat pump water heaters. Customers can purchase these units through local home improvement stores or heating, ventilating, and air conditioning contractors.

- School Education Kits (EE) – The School Education Kits Program provides free kits to fifth grade classrooms in SPS's New Mexico service area. These kits include energy efficiency educational materials and products, including four LEDs, one low-flow showerhead, a kitchen and bathroom aerator, and an LED nightlight, which are distributed along with curriculum. This program provides value beyond the direct installation of measures included in the kits by creating awareness of energy efficiency with students, teachers, and parents.

- Smart Thermostats (EE) – In SPS's 2019 Triennial, the Saver's Stat program was transitioned into an exclusively energy efficiency program utilizing the new ENERGY STAR connected Thermostat specification in Plan Year 2020. Eligible customers will be able to receive the $50 rebate for an ENERGY STAR connected thermostat through the Xcel Energy storefront, paper applications and online applications that are available to both end use customers and trade allies.

---

[11] Light Emitting Diode

Business Segment:

- Business Comprehensive Program, which is made up of the following components:
    - Cooling Efficiency (EE) – provides rebates for purchasing air conditioning equipment that exceeds standard efficiency equipment. This product also includes rebates for specific commercial refrigeration 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.

EE Goals from 2009-2020

Under the 2008 amendment of the EUEA, SPS was required to acquire cost-effective and achievable DSM to achieve no less than an 8% reduction in 2005 sales by 2020. SPS's 2005 New Mexico retail sales were 3,750,469 megawatt-hour ("MWh") therefore SPS needed to achieve savings of 300,037,520 kilowatt-hour ("kWh") or greater by 2020. SPS met this obligation in Plan Year 2018 by achieving savings of 302,366 kWh (8.06%).

Table 3-5 below shows SPS's savings achievements during the 2008 EUEA requirement, using the Portfolio Effective Useful Lifetime method (energy savings provided in gigawatt-hours ("GWh")).[12]

Table 3-5: New Mexico Actual Savings Provided by the 2008-2020 EE Programs

Year	Annual Net Customer Achievement (GWh) [13]	Cumulative Net Customer Achievement (GWh)	Cumulative % of 2005 Retail Sales
2008	3.355	3.355	0.09%
2009	14.136	17.491	0.47%
2010	23.231	40.722	1.09%
2011	35.642	76.363	2.04%
2012	31.534	107.897	2.88%
2013	34.452	142.349	3.80%
2014	30.493	172.841	4.61%
2015	32.805	202.962	5.41%
2016	31.966	234.257	6.25%
2017	29.429	263.686	7.03%
2018	38.680	302.366	8.06%
2019	36.081	320.169	8.54%
2020	46.980	348.061	9.28%

EE Goals through 2041

Under the 2019 amendment of the EUEA, SPS is required to achieve no less than savings of 5% of 2020 total retail kWh sales to as a result of EE and LM programs implemented in years 2021 through 2025. The following goals were developed in accordance with the 2008 EUEA, which SPS was following at the time of SPS's most recent Triennial Plan Filing. Note that the EUEA neither

---

[12] 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).

[13] Annual Net Customer Achievement (GWh) does not include the Energy Feedback Program's yearly savings achievement as the product only has a 1-year life.

requires nor establishes annual goals. Thus, the goals in Table 3-6 below are preliminary and subject to change in SPS's upcoming re-filing of PY 2022, Triennial Filing covering PY 2023-2025, and future Triennial Filings covering years 2025-2041.

Table 3-6: Filed and Forecasted New Mexico DSM Goals at the Customer Level for the Planning Period

Year	Demand Savings (MW)	Energy Savings (GWh)
2021	5.42	40.134
2022	8.81	56.492
2023-2041	8.81	56.492

In SPS's recent EE Potential Plan filing, filed one day before this IRP filing, SPS proposed a revised EUEA goal for 2025 based on an adjustment to SPS's 2020 total kWh retail sales used to determine the goal. The adjustment excludes kWh sales to certain customers for which there is no corresponding recovery of costs to fund EE programs due to the application of the EUEA's $75,000 per customer EE program cost-recovery cap. Based on the adjusted 2020 kWh retail sales, SPS proposed a revised EUEA energy savings goal for 2025 of 269,769 MWh to be achieved over the period of 2021 through 2025. SPS's proposed revised goal has not yet been approved by the Commission.

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 or less and all government customers. Table 3-7 below shows SPS's historic demand savings (in MW) and energy savings (in GWh) in its Texas service territory.

Table 3-7: SPS's EE and LM Achievements - 2011 to 2020 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
2018	9.57	18.908
2019	9.57	23.328
2020	11.672	25.663

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

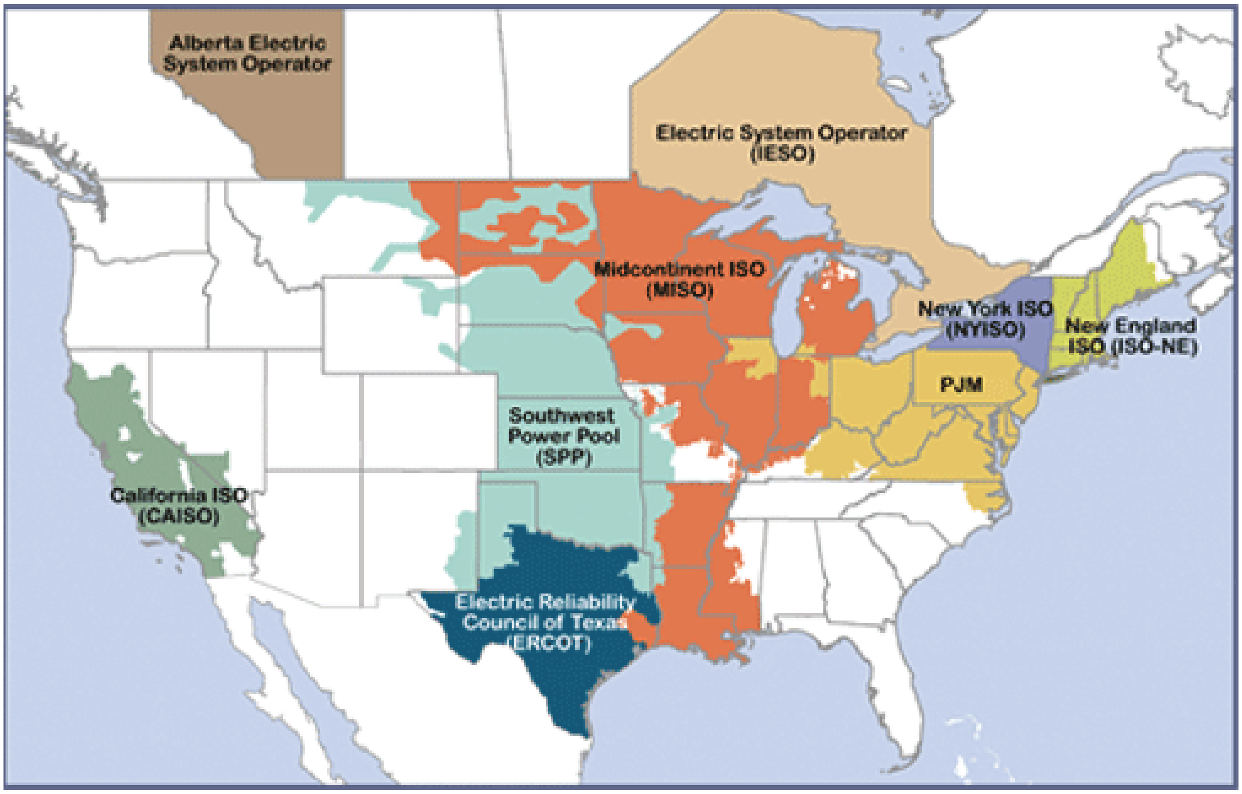
3.08 - Reserve Margin and Reserve Reliability Requirements

Southwest Power Pool Integrated Market

SPS is a member of the Southwest Power Pool. Southwest Power Pool is one of nine independent system operators ("ISO") and Regional Transmission Organizations ("RTO") in North America. Southwest Power Pool's Integrated Marketplace is the mechanism through which it facilitates the sale and purchase of electricity to ensure cost-effective electric reliability throughout a 14-state region in the Eastern Interconnect. As a Balancing Authority, Southwest Power Pool balances electric supply and demand, ensuring there is adequate generation to meet the demand.

Southwest Power Pool is responsible for generation unit commitment and dispatch across the Southwest Power Pool footprint. Additionally, Southwest Power Pool 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 performed by the Southwest Power Pool. Current expectations and future requirements regarding market operations, locational generation dispatch, congestion, and losses will impact future transmission and generation planning/siting activities.

Figure 3F.2: ISO / RTO Map



Planning and Operating Reserves

Each system must preserve an adequate supply of firm electric generation that will meet the maximum demand of its customers (i.e., the "peak" demand) and provide for unforeseen events (e.g., transmission line outages, generating unit outages, and potential increased in actual load, etc.). To accomplish these objectives, electric utilities acquire (through direct ownership or PPAs) and operate more generation capacity than is needed to meet peak demand. The available capacity above the projected peak demand is typically referred to as the "reserve margin" (i.e., "Planning Reserves"). Generally, there are two basic types of reserves: (i) Planning Reserves, which are the amount of installed capacity required above annual firm peak 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 standby 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.).

Southwest Power Pool Capacity Reserve Requirements

The Planning Reserve Margin ("PRM") for capacity is set in Section 4 of the Southwest Power Pool Planning Criteria.[14] Southwest Power Pool currently requires each Load Responsible Entity ("LRE") to have a reserve margin of at least 12% of its peak demand forecast (the planning reserve requirement is a minimum requirement, not a maximum or a target). Determination of the PRM is described in Attachment AA[15] of the Southwest Power Pool Open Access Transmission Tariff ("OATT") and is supported by a probabilistic Loss of Load Expectation ("LOLE") Study, which analyzes the ability of the Transmission Provider to reliably serve the Southwest Power Pool

---

[14] https://spp.org/Documents/58638/spp%20planning%20criteria%20v2.4.pdf

[15] https://spp.org/Documents/58597/Attachment%20AA%20Tariff.pdf

Balancing Authority Area's forecasted peak demand. The LOLE Study is performed biennially, and Southwest Power Pool studies the PRM such that the LOLE for the applicable planning year does not exceed one day in ten years, or 0.1 day per year.

3.09 - Existing Transmission Capabilities

SPS, as a member of Southwest Power Pool, 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 Southwest Power Pool 2020 Integrated Transmission Planning Assessment Report, 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 transmission projects SPS is constructing based on notifications to construct is provided as Appendix C. This list also includes service for one generator interconnection project.

Transmission Import Rights

Southwest Power Pool has a total of 1,885 MW of transmission flow capability minus the single largest contingency and other factors (i.e., imports from Palo Duro and Mammoth Wind) to deliver resources to the SPS zone from the rest of the Southwest Power Pool transmission system. SPS's reservation of this capability on a firm basis is more fully described below.

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

96 MW Import from Elk City 2 Wind

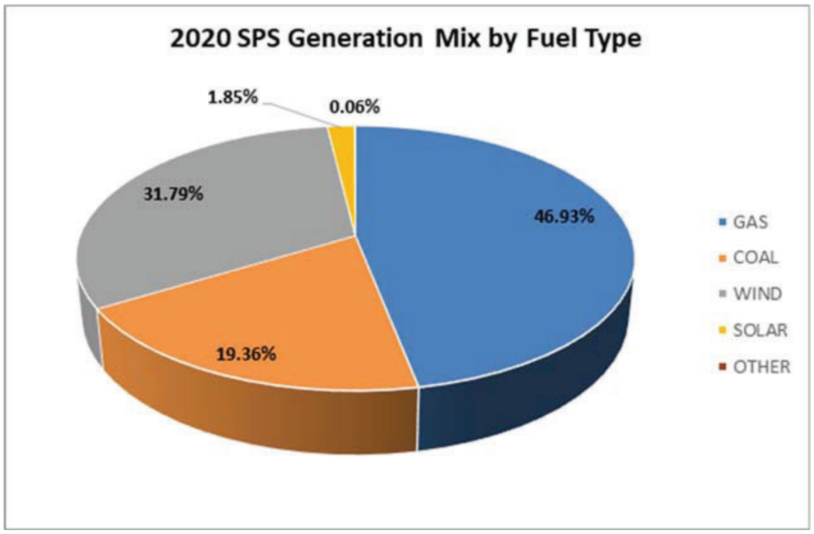
As agent for the City of Lubbock, Texas, SPS holds the firm network transmission rights to import up to 96 MW from the Elk City 2 Wind Farm, located in Oklahoma. This resource represents part of the replacement power required to serve the City of Lubbock upon termination of its full requirements contracts with SPS. The term of this service began June 1, 2019 and continues for 13 years. Any capacity associated with this reservation is held by the City of Lubbock.

3.10 - Environmental Impacts of Existing Supply-Side Resources

Percentage of MWh Generated

The percentages of MWh generated by each fuel type used by SPS for Calendar Year 2020 are provided in Figure 3F.3 below.

Figure 3F.3: Percentage of MWh Generated in 2020 by Fuel Type



SPS Emissions Information

The emission rates for SPS-owned generation resources are shown in Table 3-8 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 3-8 below.

Table 3-8: Emission and Water Consumption Rates

2020 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	7.212E-06	1.879E-03	8.625E-05	1.3736E+00	3.115E-09	8.092E-06	5.841E-09	6.242E-05	0.433
Cunningham	2	6.356E-06	1.729E-03	7.935E-05	1.2582E+00	2.621E-09	1.059E-04	5.242E-09	5.743E-05	
Cunningham	3	6.438E-06	6.591E-04	5.348E-05	1.2980E+00	2.894E-09	5.460E-05	0.000E+00	2.293E-05	
Cunningham	4	6.987E-06	6.553E-04	5.577E-05	1.3906E+00	3.011E-09	9.360E-05	0.000E+00	2.457E-05	
Harrington	1	4.912E-03	1.699E-03	5.283E-04	2.1800E+00	1.081E-08	1.126E-03	6.160E-08	3.913E-05	0.698
Harrington	2	4.768E-03	1.412E-03	1.244E-04	2.1354E+00	8.097E-09	1.156E-03	2.089E-08	3.770E-05	
Harrington	3	4.984E-03	1.489E-03	1.453E-04	2.2797E+00	7.923E-09	1.124E-03	2.181E-08	3.663E-05	
Jones	1	6.408E-06	1.490E-03	8.071E-05	1.2696E+00	2.782E-09	2.549E-04	5.286E-09	5.841E-05	0.326
Jones	2	6.538E-06	1.138E-03	8.219E-05	1.2932E+00	2.869E-09	2.595E-04	5.314E-09	5.947E-05	
Jones	3	6.263E-06	3.059E-04	2.714E-05	1.2409E+00	2.681E-09	1.012E-04	0.000E+00	2.089E-06	
Jones	4	6.203E-06	3.052E-04	3.721E-05	1.2285E+00	2.656E-09	1.143E-04	0.000E+00	3.101E-06	
Maddox	1	6.538E-06	1.975E-03	8.118E-05	1.2928E+00	2.799E-09	7.613E-06	4.398E-09	5.875E-05	0.656
Maddox	2	1.052E-05	3.767E-03	9.007E-05	1.5964E+00	3.620E-09	2.047E-05	6.723E-09	2.866E-05	
Maddox	3	1.791E-05	7.648E-03	1.567E-04	2.7871E+00	0.000E+00	5.448E-04	0.000E+00	5.075E-05	
Nichols	1	6.783E-06	1.109E-03	8.171E-05	1.3047E+00	2.833E-09	2.580E-04	5.261E-09	5.913E-05	0.701
Nichols	2	1.123E-05	1.360E-03	8.595E-05	1.3718E+00	2.708E-09	2.714E-04	5.417E-09	6.220E-05	
Nichols	3	1.146E-05	1.887E-03	8.538E-05	1.3632E+00	2.989E-09	2.696E-04	5.663E-09	6.179E-05	
Plant X	1	8.394E-06	7.923E-03	1.039E-04	1.6505E+00	3.412E-09	1.148E-03	6.824E-09	7.520E-05	0.738
Plant X	2	7.058E-06	8.819E-04	8.747E-05	1.3941E+00	3.087E-09	2.761E-04	5.659E-09	6.326E-05	
Plant X	3	0.000E+00	0.000E+00	0.000E+00	0.0000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	
Plant X	4	6.597E-06	1.638E-03	8.225E-05	1.3095E+00	2.851E-09	2.597E-04	5.402E-09	5.951E-05	
Quay County	1	3.202E-05	1.608E-02	2.516E-04	2.7712E+00	0.000E+00	2.382E-04	4.058E-07	8.389E-04	0.000
Tolk	1	4.884E-03	1.737E-03	7.675E-05	2.2389E+00	8.898E-09	2.514E-03	1.297E-08	3.933E-05	0.650
Tolk	2	5.158E-03	2.165E-03	1.203E-04	2.5482E+00	8.112E-09	2.440E-03	1.882E-08	3.833E-05	

3.11 - 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 electric grid from multiple types of risks. The SPS transmission system is planned and designed for single contingency or N-1 standards, and therefore has the ability to sustain overall grid reliability in the face of various types of generator and transmission contingencies. In addition, SPS is compliant with the applicable NERC[16] 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. Furthermore, SPS's owned generation units have redundant fuel supplies, mitigating the risk of supply-source failures. Additionally, purchases from the Southwest Power Pool market would typically address any deficiencies in SPS resources.

---

[16] North American Electric Reliability Corporation

Section 4. CURRENT LOAD FORECAST

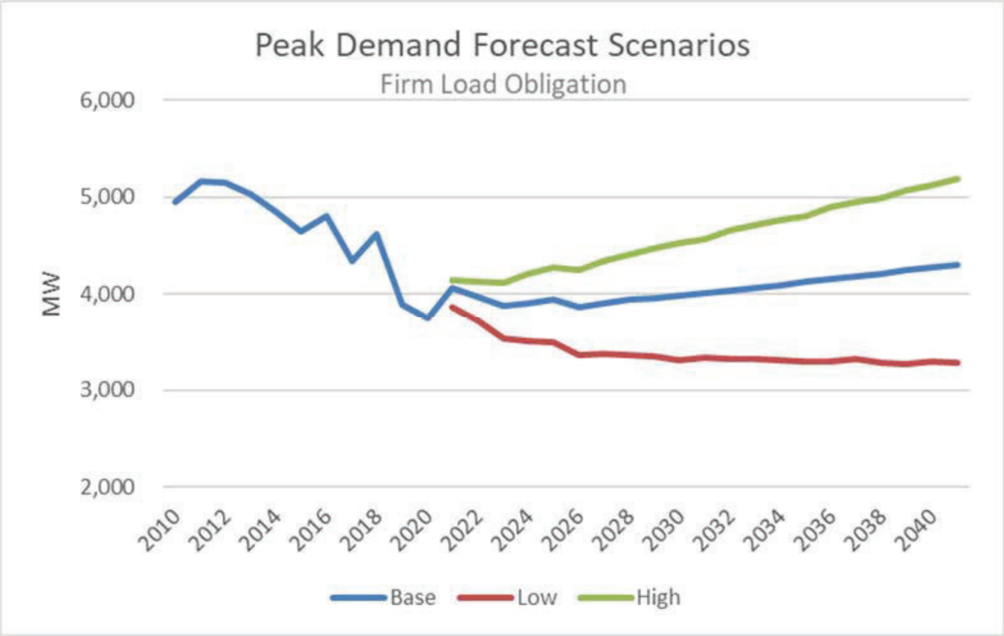
4.01 - Forecast Overview

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 increase at a compounded annual growth rate of 0.4% or an average of 12 MW per year through the Planning Period (2022-2041). Growth in retail demand is expected to more than offset the impact of losing wholesale customers through the forecast period. SPS's base or median energy sales are forecasted to increase at a compounded annual growth rate of 0.6% or an average growth rate of 154 GWh during the same period. The load growth over the Planning Period contrasts to the historical annual average load decline of -2.7% over the last 10 years (ending 2020). The historical annual average energy decline over the ten years ending 2020 is -1.9%. Load and energy decreases were driven primarily 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 paused the oil and gas expansion in southeastern New Mexico and the SPS region has seen a decline in potash mining in the last decade. Finally, 2020 sales and demands were negatively impacted by the business shutdowns and economic slowdown as a result of the COVID-19 pandemic.

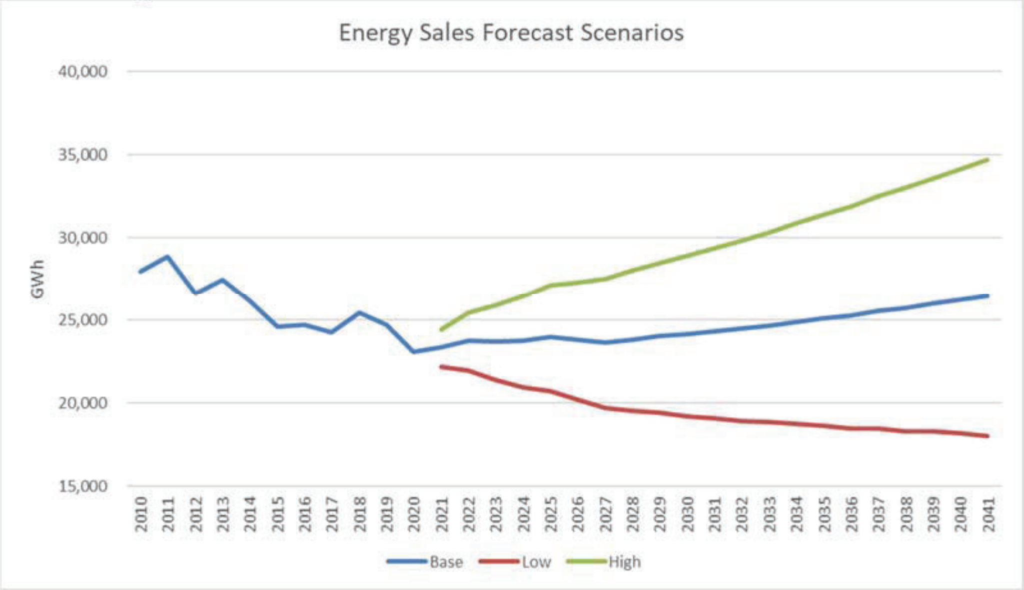
The SPS low forecast scenario of coincident peak demand decreases at a compounded annual growth rate of -0.6% through the Planning Period, and the high forecast scenario of coincident peak demand increases at a compounded annual growth rate of 1.2% per year. Figure 4F.1 below contains a graphical representation 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 2041, and the annual energy sales high forecast scenario increases at a compounded annual growth rate of 1.6% 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 eleven years of history starting in 2010, and it shows annual growth and compounded growth to/from 2020. The bold line across the table delineates historical from projected information.

The base peak demand forecast assumes economic growth based on projections from IHS Markit[17] 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 2020). SPS's firm peak demand decreased by -1,203 MW or -24.3%, from 2010 to 2020. Load

---

[17] As discussed below, IHS Markit is a trusted data source for forecasting professionals that SPS uses for economic and demographic data and forecasts.

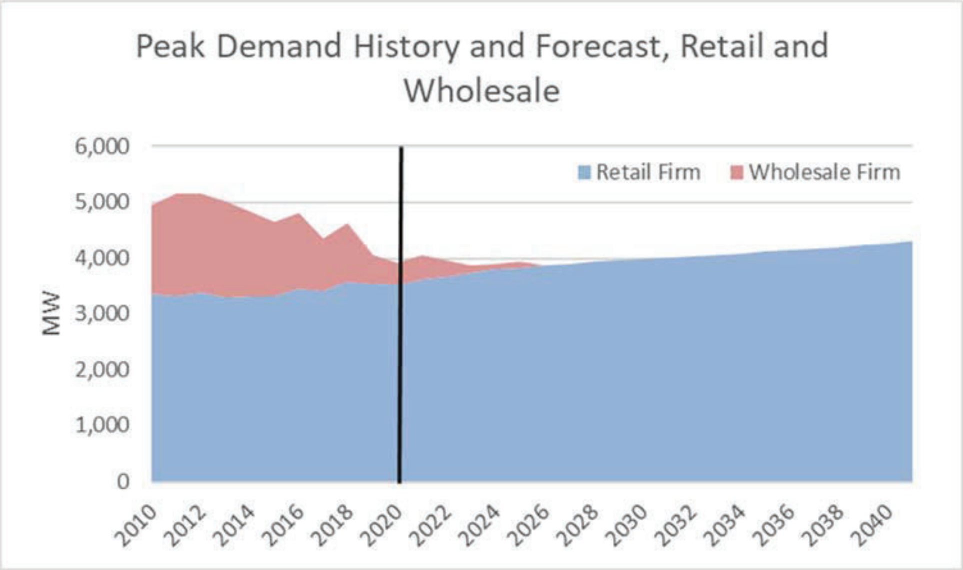
growth was dampened as a result of decreased demand from wholesale customers due to changes in contracted load. In the 10-year period ending 2020, the population in the SPS service territory grew by an annual average rate of 0.1% per year. Combined Real Gross County Product ("GCP") for the counties in the SPS service territory averaged gains of 2.0% from 2010 through 2020. During this same period, SPS gained about 17,900 residential customers, for total growth of 6.0%.

The peak demand forecast compounded annual growth rate for the Planning Period through 2041 is 0.4%. This is stronger growth than seen over the past ten years, which averaged annual declines of 2.7%. Retail peak demand for the Planning Period increases at a compounded annual growth rate of 0.8%, compared to the ten-year period ending 2020 compounded annual growth rate of 0.4%. Retail peak demand growth is driven by population and economic growth in the service territory, continued expansion of the oil and gas industry in southeastern New Mexico, and adoption of electric vehicles. Wholesale peak demand for the Planning Period gradually decreases as contracts expire and is zero starting in 2026. SPS assumes that expiring wholesale contracts will not be renewed after their known expiration dates.

SPS service territory GCP is expected to average 2.3% through 2041. Population growth is similar to the recent past, with annual gains averaging 0.3% through the Planning Period. SPS projects residential customer growth will average annual increases of 0.5% per year through 2041.

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: Peak Demand History and Forecast, Retail and Wholesale

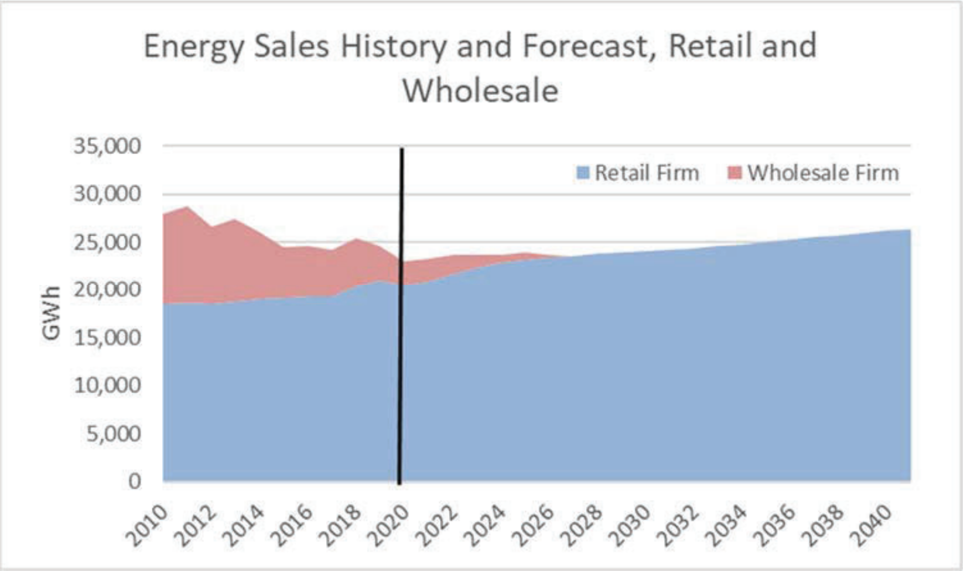


4.03 - Annual Energy Discussion

SPS is anticipating energy sales in the base case forecast to average 0.6% growth annually over the Planning Period. The 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, much of that also impacted by the declining wholesale sales. Energy sales decreased by 4,853 GWh, or -17.3%, from 2010 to 2020. The energy sales forecast's compounded annual growth rate for the Planning Period through 2041 is 0.6%. The growth in retail energy sales is expected to more than offset the declines in wholesale. Retail energy sales for the Planning Period increase at a compounded annual growth rate of 1.0%, similar to the 10-year period ending 2020 compounded annual growth rate of 1.0%. 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, and the adoption of electric vehicles. Base case wholesale energy sales are forecasted to decline steadily before reaching zero in 2027. Figure 4F.4 shows SPS's energy sales by retail and wholesale customer class graphically.

Figure 4F.4: Energy Sales History and Forecast, Retail and Wholesale



4.04 - Electric Vehicles

SPS has developed a projection of electric vehicle adoption in its service territory. SPS expects to have 307,700 electric vehicles in its service territory by 2041. These vehicles are expected to contribute 1,972 GWh to annual energy sales and 241 MW to coincident summer peak demand.

4.05 - 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 2021 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.

4.06 - 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 2022-2041.

IHS Markit, 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.

4.07 - 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 with the customer.

4.08 - 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, such 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.

4.09 - 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.

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 99.6 degrees Fahrenheit for each July during the forecast period, it is unlikely that each year the actual peak day maximum temperature will be 99.6 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.

4.10 - 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 two-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)

4.11 - 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. 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.

4.12 - 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 not been adjusted to account for behind-the-meter generation and demand response.

4.13 - Forecast Accuracy

SPS reviews its demand and energy forecasts for accuracy annually. 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

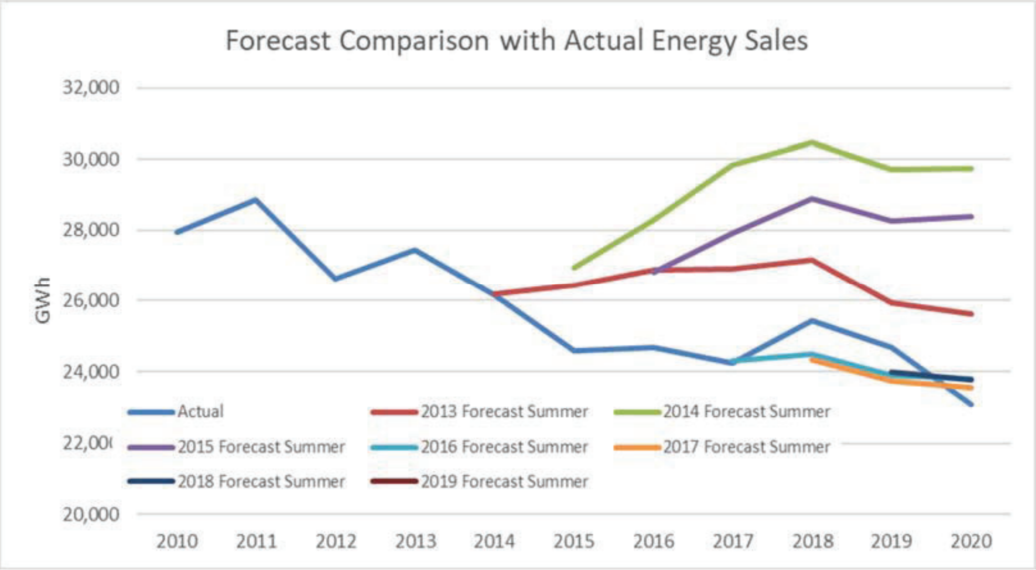
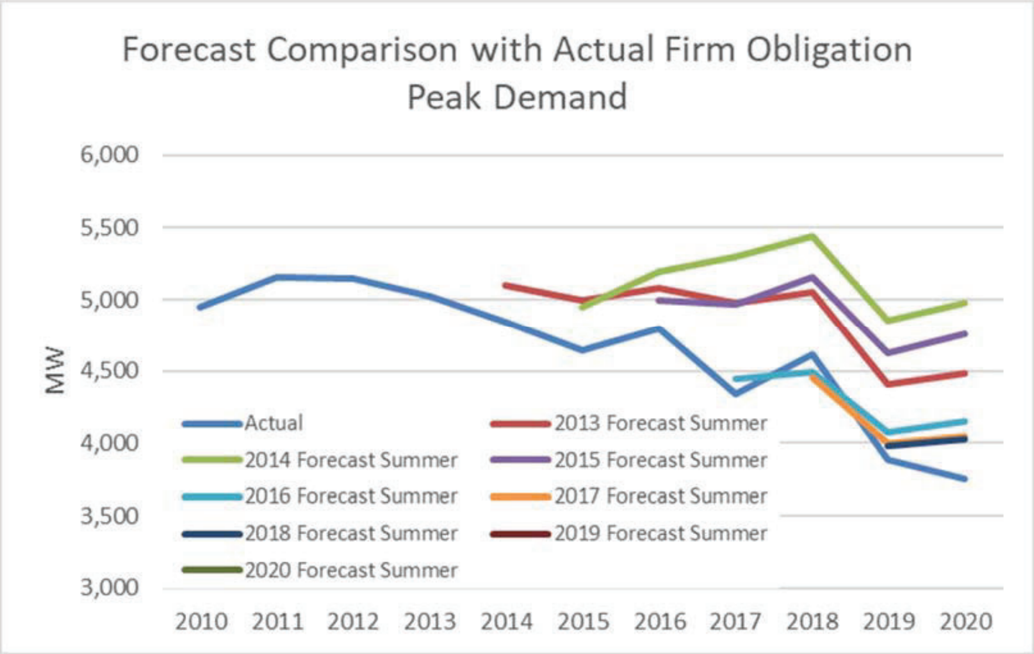


Figure 4F.6: Forecast Comparison with Actual Firm Load Obligation Peak



4.14 - Econometric Model Parameters

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

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, where applicable, 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 the planning reserve margin exceeds generation supply, additional generation is needed. Table 5-1 provides a summarized L&R table for the SPS electric system assuming the base load forecast described in Section 4.

Table 5-1: Summarized L&R Table

		2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)
(a)	Owned Generation Capacity	4,333	4,270	4,159	4,159
(b)	Purchased Power Capacity	1,208	1,254	1,030	1,020
(c)	Total Generation Capacity	5,541	5,524	5,189	5,179
(d)	Firm Load Obligation	3,969	3,874	3,899	3,937
(e)	Capacity Margin (12%)	476	465	468	472
(f)	Total Firm Load + Reserves	4,445	4,339	4,367	4,409
(g)	Resources Position Long / (Short)	1096	1184	823	770

The Summarized L&R table above provides foresight into the amounts and timing of future generation resource needs. As shown in the summarized L&R table, SPS has sufficient supply-side resources to meet its planning reserve margin requirements during the Action Plan and, therefore, does not require any new generating resources. However, as described in Section 7, SPS may consider procuring additional resources if they are expected to provide other benefits, such as economical energy savings.

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

SPS Loads & Resource Balance Summer 2022 - 2031 - Base Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EXISTING RESOURCES										
Owned - Thermal Resources	4,333	4,070	3,959	3,959	3,714	3,714	3,523	3,411	3,411	3,165
Owned - Renewable Resources	0	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	797	797	574	574	574	574	574	574	574	574
Purchased Power - Renewable Resources	410	456	456	446	438	418	375	375	375	375
TOTAL ACCREDITED CAPACITY (MW)	5,541	5,524	5,189	5,179	4,926	4,906	4,672	4,560	4,560	4,314
LOAD										
Retail	3,696	3,778	3,827	3,865	3,895	3,933	3,962	3,988	4,009	4,034
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	301	125	100	100	0	0	0	0	0	0
DSM / Interruptibles	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(27)	(27)
FIRM LOAD OBLIGATION	3,969	3,874	3,899	3,937	3,867	3,905	3,934	3,961	3,982	4,007
RESERVES										
Planning Reserve Margin @ 12%	476	465	468	472	464	469	472	475	478	481
TOTAL PLANNING RESERVE MARGIN	476	465	468	472	464	469	472	475	478	481
CAPACITY REQUIREMENT	4,445	4,339	4,366	4,409	4,331	4,374	4,407	4,436	4,460	4,488
RESOURCE POSITION (MW): LONG/(SHORT)	1,096	1,184	823	770	595	532	266	124	101	(174)

SPS Loads & Resource Balance Summer 2032 - 2041 - Base Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EXISTING RESOURCES										
Owned - Thermal Resources	2,922	1,853	1,853	1,593	1,593	1,253	1,253	898	898	336
Owned - Renewable Resources	200	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	574	574	0	0	0	0	0	0	0	0
Purchased Power - Renewable Resources	343	343	343	129	88	88	88	88	88	88
TOTAL ACCREDITED CAPACITY (MW)	4,039	2,970	2,396	1,922	1,881	1,541	1,541	1,186	1,186	624
LOAD										
Retail	4,060	4,088	4,111	4,149	4,181	4,211	4,235	4,269	4,305	4,331
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	0	0	0	0	0	0	0	0	0	0
DSM / Interruptibles	(27)	(27)	(26)	(27)	(28)	(28)	(28)	(29)	(29)	(29)
FIRM LOAD OBLIGATION	4,033	4,061	4,085	4,122	4,153	4,183	4,207	4,241	4,275	4,302
RESERVES										
Planning Reserve Margin @ 12%	484	487	490	495	498	502	505	509	513	516
TOTAL PLANNING RESERVE MARGIN	484	487	490	495	498	502	505	509	513	516
CAPACITY REQUIREMENT	4,517	4,549	4,575	4,616	4,651	4,685	4,712	4,749	4,788	4,819
RESOURCE POSITION (MW): LONG/(SHORT)	(478)	(1,578)	(2,179)	(2,694)	(2,770)	(3,144)	(3,171)	(3,563)	(3,602)	(4,194)

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

SPS Loads & Resource Balance Summer 2022 - 2031 - High Load Case Forecast

Based on March 2021 Load Forecast

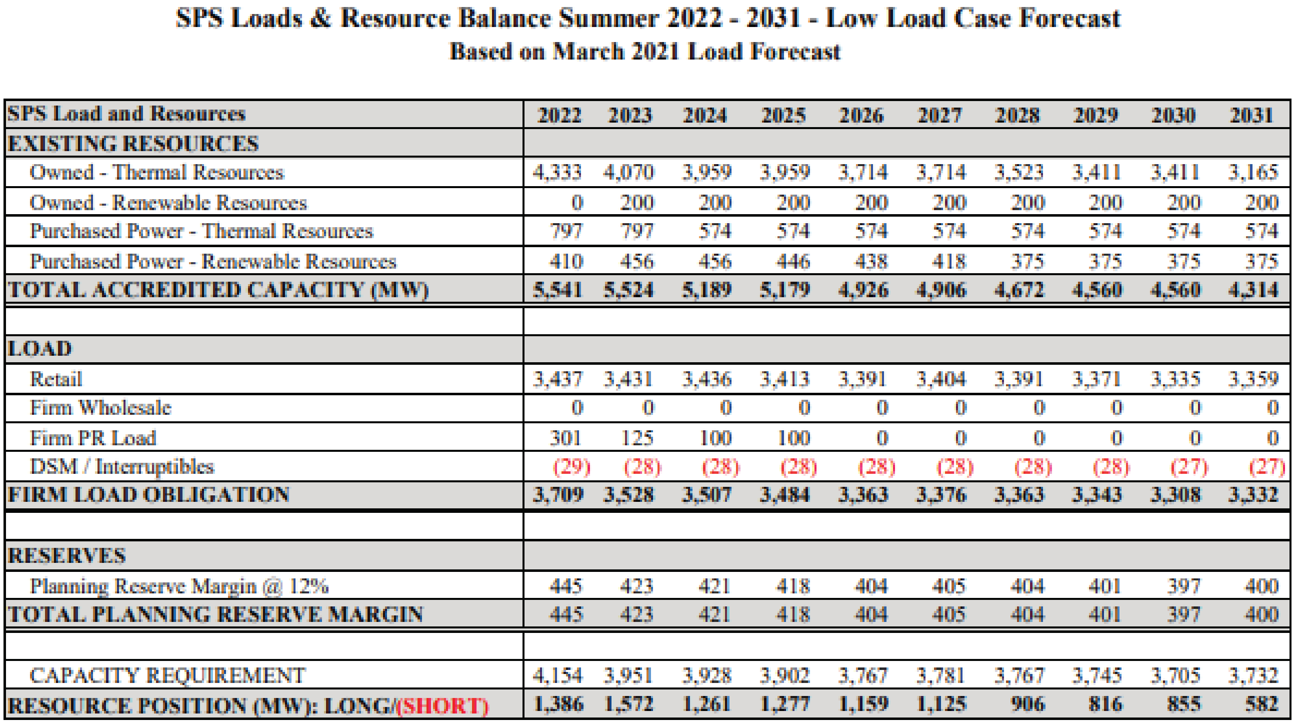
SPS Load and Resources	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EXISTING RESOURCES										
Owned - Thermal Resources	4,333	4,070	3,959	3,959	3,714	3,714	3,523	3,411	3,411	3,165
Owned - Renewable Resources	0	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	797	797	574	574	574	574	574	574	574	574
Purchased Power - Renewable Resources	410	456	456	446	438	418	375	375	375	375
TOTAL ACCREDITED CAPACITY (MW)	**5,541**	**5,524**	**5,189**	**5,179**	**4,926**	**4,906**	**4,672**	**4,560**	**4,560**	**4,314**
LOAD										
Retail	3,860	4,018	4,135	4,197	4,268	4,361	4,431	4,492	4,549	4,593
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	301	125	100	100	0	0	0	0	0	0
DSM / Interruptibles	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(27)	(27)
FIRM LOAD OBLIGATION	**4,133**	**4,115**	**4,207**	**4,269**	**4,240**	**4,333**	**4,403**	**4,464**	**4,522**	**4,565**
RESERVES										
Planning Reserve Margin @ 12%	496	494	505	512	509	520	528	536	543	548
TOTAL PLANNING RESERVE MARGIN	496	494	505	512	509	520	528	536	543	548
CAPACITY REQUIREMENT	4,629	4,608	4,712	4,781	4,748	4,853	4,932	5,000	5,064	5,113
RESOURCE POSITION (MW): LONG/(SHORT)	**912**	**915**	**477**	**398**	**178**	**53**	**(259)**	**(440)**	**(504)**	**(799)**

SPS Loads & Resource Balance Summer 2032 - 2041 - High Load Case Forecast

Based on March 2021 Load Forecast

SPS Load and Resources	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EXISTING RESOURCES										
Owned - Thermal Resources	2,922	1,853	1,853	1,593	1,593	1,253	1,253	898	898	336
Owned - Renewable Resources	200	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	574	574	0	0	0	0	0	0	0	0
Purchased Power - Renewable Resources	343	343	343	129	88	88	88	88	88	88
TOTAL ACCREDITED CAPACITY (MW)	**4,039**	**2,970**	**2,396**	**1,922**	**1,881**	**1,541**	**1,541**	**1,186**	**1,186**	**624**
LOAD										
Retail	4,679	4,732	4,793	4,826	4,918	4,980	5,015	5,095	5,154	5,211
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	0	0	0	0	0	0	0	0	0	0
DSM / Interruptibles	(27)	(27)	(26)	(27)	(28)	(28)	(28)	(29)	(29)	(29)
FIRM LOAD OBLIGATION	**4,652**	**4,706**	**4,767**	**4,799**	**4,890**	**4,952**	**4,987**	**5,066**	**5,125**	**5,182**
RESERVES										
Planning Reserve Margin @ 12%	558	565	572	576	587	594	598	608	615	622
TOTAL PLANNING RESERVE MARGIN	558	565	572	576	587	594	598	608	615	622
CAPACITY REQUIREMENT	5,210	5,270	5,339	5,375	5,477	5,547	5,585	5,674	5,740	5,804
RESOURCE POSITION (MW): LONG/(SHORT)	**(1,171)**	**(2,300)**	**(2,942)**	**(3,453)**	**(3,595)**	**(4,005)**	**(4,044)**	**(4,488)**	**(4,553)**	**(5,180)**

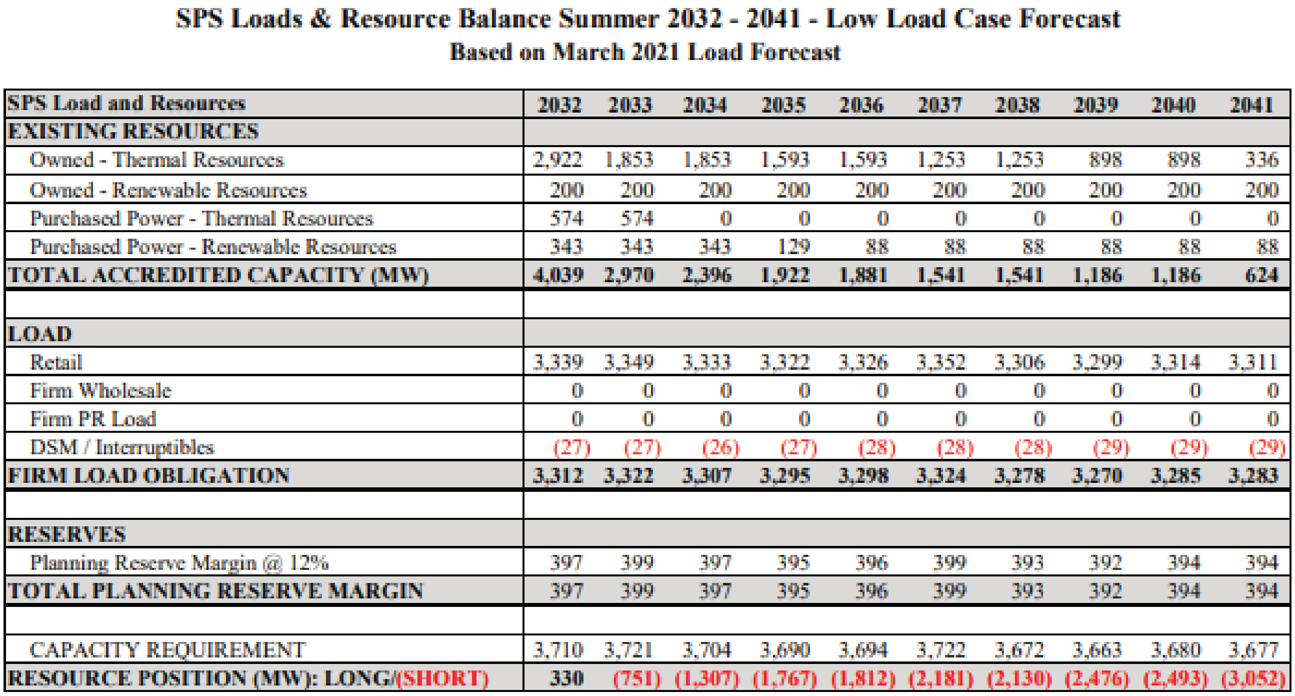
Table 5-4: Summary of SPS Low Load Case L&R



SPS Loads & Resource Balance Summer 2022 - 2031 - Low Load Case Forecast

Based on March 2021 Load Forecast

SPS Load and Resources	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
EXISTING RESOURCES										
Owned - Thermal Resources	4,333	4,070	3,959	3,959	3,714	3,714	3,523	3,411	3,411	3,165
Owned - Renewable Resources	0	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	797	797	574	574	574	574	574	574	574	574
Purchased Power - Renewable Resources	410	456	456	446	438	418	375	375	375	375
TOTAL ACCREDITED CAPACITY (MW)	**5,541**	**5,524**	**5,189**	**5,179**	**4,926**	**4,906**	**4,672**	**4,560**	**4,560**	**4,314**
LOAD										
Retail	3,437	3,431	3,436	3,413	3,391	3,404	3,391	3,371	3,335	3,359
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	301	125	100	100	0	0	0	0	0	0
DSM / Interruptibles	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(27)	(27)
FIRM LOAD OBLIGATION	**3,709**	**3,528**	**3,507**	**3,484**	**3,363**	**3,376**	**3,363**	**3,343**	**3,308**	**3,332**
RESERVES										
Planning Reserve Margin @ 12%	445	423	421	418	404	405	404	401	397	400
TOTAL PLANNING RESERVE MARGIN	445	423	421	418	404	405	404	401	397	400
CAPACITY REQUIREMENT	4,154	3,951	3,928	3,902	3,767	3,781	3,767	3,745	3,705	3,732
RESOURCE POSITION (MW): LONG/(SHORT)	**1,386**	**1,572**	**1,261**	**1,277**	**1,159**	**1,125**	**906**	**816**	**855**	**582**



SPS Loads & Resource Balance Summer 2032 - 2041 - Low Load Case Forecast

Based on March 2021 Load Forecast

SPS Load and Resources	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
EXISTING RESOURCES										
Owned - Thermal Resources	2,922	1,853	1,853	1,593	1,593	1,253	1,253	898	898	336
Owned - Renewable Resources	200	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	574	574	0	0	0	0	0	0	0	0
Purchased Power - Renewable Resources	343	343	343	129	88	88	88	88	88	88
TOTAL ACCREDITED CAPACITY (MW)	**4,039**	**2,970**	**2,396**	**1,922**	**1,881**	**1,541**	**1,541**	**1,186**	**1,186**	**624**
LOAD										
Retail	3,339	3,349	3,333	3,322	3,326	3,352	3,306	3,299	3,314	3,311
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	0	0	0	0	0	0	0	0	0	0
DSM / Interruptibles	(27)	(27)	(26)	(27)	(28)	(28)	(28)	(29)	(29)	(29)
FIRM LOAD OBLIGATION	**3,312**	**3,322**	**3,307**	**3,295**	**3,298**	**3,324**	**3,278**	**3,270**	**3,285**	**3,283**
RESERVES										
Planning Reserve Margin @ 12%	397	399	397	395	396	399	393	392	394	394
TOTAL PLANNING RESERVE MARGIN	397	399	397	395	396	399	393	392	394	394
CAPACITY REQUIREMENT	3,710	3,721	3,704	3,690	3,694	3,722	3,672	3,663	3,680	3,677
RESOURCE POSITION (MW): LONG/(SHORT)	**330**	**(751)**	**(1,307)**	**(1,767)**	**(1,812)**	**(2,181)**	**(2,130)**	**(2,476)**	**(2,493)**	**(3,052)**

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 an electric 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 is typically achieved through BESS, which are electrochemical devices that store energy for use when needed. Battery chemistries vary in technical characteristics; however, lithium-ion chemistries are currently the most widely utilized in the U.S. The most common thermal, renewable, and BESS technologies are described in more detail below

Examples of Thermal Supply-Side Resources

- CTG (Combustion Turbine Generator) – Combustion Turbine Generators are typically referred to as simple-cycles because they operate on a single thermodynamic cycle known as the Brayton Cycle. CTGs can operate on several fuel sources but are typically fired with natural gas which turns a turbine coupled with an electric generator to generate electricity. Recent CTG technological advancements have enabled operation, for both new and retrofitted CTGs, to utilize carbon-free hydrogen as an alternative fuel source. CTGs are available in a wide range of sizes (4 MW to over 400 MW) and are typically inexpensive to build but are relatively inefficient sources of generation. As such, they are often considered "peaking" units, which are utilized during times of high electric demand. CTGs also provide extremely fast start capabilities and ramp rates, providing the capability to follow demand and intermittent renewable generation, such as wind and solar.

- CC (Combined Cycle) – Combined Cycle ("CC") facilities utilize single or multiple CTGs in conjunction with Heat Recovery Steam Generators ("HRSG") and a Steam Turbine Generator ("STG") to generate electricity. These facilities are known as CCs because they combine the Brayton Cycle, mentioned above in the CTG section, with the Rankine Cycle, the HRSG, and STG's thermodynamic cycle. The waste heat from the CTG's exhaust gas is ducted through a HRSG which generates steam to turn a steam turbine coupled with an electric generator which produces additional electric power along with the CTGs. CCs can operate in multiple configurations, i.e., 1-on-1, 2-on-1, or 3-on-1, with the first number being the number of CTGs and HRSGs and the second number being the steam turbine, which is appropriately sized to efficiently utilize the total CTG waste heat. For example, a 2-on-1 CC consists of two CTGs and HRSGs and one STG. CCs can also operate on various fuel sources, including hydrogen, since the base motive drivers are the CTGs mention in the CTG section above. CC units come in a variety of sizes near 100 MW to over 1,600 MW depending on the specific configuration of the facility. CC units have higher installed costs than CTG units, but better efficiency and operating costs, thus CCs offer more expensive capacity but lower cost energy when compared to simple cycle CTGs.

Examples of Renewable Supply-Side Resources

- Solar – Solar generation resources convert the sun's energy (photons of light) into electricity. Solar generation has several forms, such as PV, concentrating PV, or concentrating solar power. Solar generation is intermittent, like other renewable energy resources. In SPS's service territory, solar generation capacity factors typically range from 30% - 35%. 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 occurs prior to the time when electric demand reaches its highest level. Therefore, less than the full nameplate generating capability of solar generation is counted toward meeting electric system peak demands.
- Wind – Wind generation typically consists of large, three-bladed turbines mounted atop towers over 250 feet tall arranged over several thousand acres of land. Wind generation consist of a multiple Wind Turbine Generators 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. Wind generation units in New Mexico and Texas typically have an annual capacity factor in the 45-55% range, depending on the specific location within these regions. As maximum wind generation output is variable and often noncoincidental to peak system loads, wind generation has a low capacity value when compared to other generating resource (including solar generation).

Examples of Energy Storage Supply-Side 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 to over 250 MW and vary in duration from 2 – 8 hours. 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 ICO and the Saver's Switch 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 an alternative for investments in new generating facilities or demand-side resources, where transmission upgrades are used to access existing generation within other transmission-constrained areas.

Supply-Side Resource Comparison

Each of the different supply-side generation technologies described above have distinctly different technical characteristics as well as capital and operating cost characteristics. These characteristics dictate how various technologies are dispatched or used to serve load requirements of the system. A high-level comparison of the supply-side generating resources is shown below in Table 6.1.

Table 6-1: Supply-Side Generating Resources Comparison

Costs	Gas CT	Gas CC	Wind	Solar	BESS
Installed Cost	Low	Mid	High	Mid/High	High
Operating Costs	High	Mid	Low	Low	Low
Expected Capacity Factor %	0-25%	25-80%	45-55%	30%	N/A
CO_2[18] per MWh	Medium	Low	None	None	N/A

6.01 - Resource Options Considered

SPS's 2021 IRP considers each of the five resource options described above; i.e., CTG, CC, Solar, Wind, and BESS. Depending on the year the resource option was available for selection in the EnCompass production cost model, SPS used one of two different approaches when determining the cost and technical characteristics of new generating resources. First, as shown in Table 6-2, for the thermal resources available for selection in 2026 and beyond, SPS used general generic characteristics such as asset life, capital costs, fixed and variable operating and maintenance costs, fuel type (when applicable), heat rates (when applicable), and CO_2 emissions. These general generic characteristics are carried through each year of the planning period and costs are escalated where stated. Annual

---

[18] Carbon Dioxide

capacity factors are not an input for thermal generic resources, rather they are calculated by the EnCompass production cost model. The EnCompass output files will be provided under Protective Order. Availability factor can vary year-on-year and are also available in the EnCompass output files. Second, for resources available for selection between the years 2023 and 2025, inclusive, SPS used information contained in proposals received from the Tolk Analysis Request for Information ("RFI").

6.02 - Generic Resources

Generic characteristics are developed "in-house" utilizing SPS's experience with these technologies and leveraging market relationships to validate any characteristic assumptions. When determining the future cost of renewable resources, SPS also leveraged data from National Renewable Energy Laboratory's ("NREL") 2020 Annual Technology Baseline ("ATB"). These resource characteristics were then included in the EnCompass production cost model to represent how these various technologies would integrate with the existing SPS electric system to serve future customer load projections. The cost of SPS's generic thermal resources, which are summarized below in Table 6-2, were estimated in current dollars and then escalated at 2% per year thereafter. SPS used NREL ATB cost data as a baseline for estimating annual costs for wind, solar and BESS resources. Annual cost estimates for wind, solar and BESS incorporated applicable renewable tax credits for the year the project was expected to be in-serviced and, where applicable, continued declining costs in real dollars. The annual cost estimates for wind, solar, and a 4-hour BESS resource are shown below in Table 6-3. Additional cost and performance information related to the generic thermal resource types is presented in Appendix G.

Table 6-2: Thermal Generic Resource Summary Cost and Performance - 2021[19]

Technology	Asset Life (yrs)	Capacity (MW)	Capacity Cost $/kw	Fixed O&M[20] $000/yr	On-Going Capital $000/yr	VOM $/MWh	Heat Rate MMBTu/MWh	CO_2 Emissions Lbs/MMBTu
2x1 CC	40	771	$773	$5,400	$5,150	$1.22	6,608	117
CTG	40	201	$495	$1,120	$1,313	$0.00	10,009	117

Table 6-3: Generic Renewable and BESS Resource Cost by Year

Levelized Costs by In-Service Year (LCOE)			
EOY[21]	**Wind ($/MWh)**	**Solar ($/MWh)**	**Battery ($/kW-mo)**
2026	$ 39.20	$ 30.68	$ 12.80
2027	$ 38.96	$ 29.14	$ 12.57
2028	$ 38.70	$ 27.56	$ 12.33
2029	$ 38.41	$ 25.94	$ 12.09
2030	$ 38.78	$ 26.08	$ 12.17
2031	$ 39.16	$ 26.21	$ 12.26
2032	$ 39.53	$ 26.35	$ 12.34
2033	$ 39.91	$ 26.48	$ 12.42
2034	$ 40.28	$ 26.61	$ 12.50
2035	$ 40.65	$ 26.74	$ 12.58
2036	$ 41.03	$ 26.87	$ 12.58
2037	$ 41.40	$ 27.00	$ 12.57
2038	$ 41.76	$ 27.12	$ 12.55
2039	$ 42.13	$ 27.24	$ 12.51
2040	$ 42.49	$ 27.36	$ 12.47
2041	$ 42.86	$ 27.47	$ 12.41

6.03 - Proposals Received from the Tolk Analysis RFI

As part of the Tolk Analysis, SPS was required to issue an RFI. The proposals received from the RFI generally included indicative commercial operation dates through the end of year 2025.

---

[19] Table 6-2 reflects 2021 costs escalating at 2% per year.

[20] Operations and Maintenance

[21] End of Year

Therefore, rather than use generic characteristics through 2025, SPS utilized the proposals received from the RFI for resources that were available for selection in the EnCompass production cost model between 2023 – 2025. For the purposes of determining the most cost-effective portfolio of resources, SPS utilized the commercial operational dates provided from perspective bidders. However, as described in more detail in Section 7.07, it is doubtful that many of the proposals can still meet the commercial operation dates they submitted in the RFI.

As a result of the RFI, SPS received information from 18 different bidders, with most bidders submitting multiple proposals and/or pricing structures. The majority of proposals submitted were for new wind generation, solar generation, or solar generation plus battery energy storage.

Wind Generation

SPS received wind proposals ranging from a little over 100 MW up to 1,000 MW. The median pricing of wind proposals received from the RFI was \$23.05/MWh, assuming 60% production tax credits ("PTC") eligibility. However, as discussed in detail in the Tolk Analysis, most proposals did not include the full cost of the necessary transmission network upgrades required to interconnect the new generation.

Solar Generation

SPS received solar proposals ranging from less than 50 MW to just over 1,000 MW. The median pricing of solar proposals received from the RFI was \$27.52/MWh. SPS received solar proposals that included 30%, 26%, and 10% investment tax credits ("ITC"). Again, most proposals did not include the full cost of the necessary transmission network upgrades to interconnect the new generation.

Battery Energy Storage Systems

SPS did not receive any standalone BESS resources. Instead, SPS received several proposals for solar generation coupled with BESS as this allowed the BESS to qualify for the same ITC as the solar generation. To qualify for the solar ITC, SPS assumed the BESS must be charged by the coupled solar generation for the first 5 years of operation. The incremental cost of a 4-hour BESS was approximately $6/kW-month to $8/kW-month inclusive of qualifying ITCs.

6.04 - Other Supply-side Resource Technologies

SPS received other supply-side resource technology proposals from the RFI. These technologies included gravitational energy storage, compressed air storage, and a 1-on-1 CC with hydrogen production and storage. Gravitational and compressed air storage provide the potential for longer duration energy storage than current lithium-ion BESS. In the absence of carbon-free fuels, longer duration energy storage is critical to achieving New Mexico's carbon free energy aspirations. However, neither gravitational or compressed air storage is currently well-established, and the proposals received are in the early developmental stage; as such, it is highly doubtful that either proposal could achieve commercial operation within the Action Plan and therefore were not considered for SPS's most cost-effective portfolio of resources. Currently, the cost of hydrogen production and storage is cost prohibitive when compared to other energy resources, such as wind, solar or even traditional gas-fired CCs. However, as demonstrated in Section 7, as SPS transitions to a more renewable-heavy portfolio of generating resources, SPS will need firm and dispatchable resources. Hydrogen-capable resources are one possibility to fulfill this critical need in the future.

Accredited Capacity - Planning Reserve Margin

Each of the supply-side resource technologies described above has the ability to contribute capacity to SPS's planning reserve margin requirements. Thermal resources, such as CTGs and CCs, can be dispatched when needed and provide 100% of their rated capacity towards SPS's planning reserve margin. Intermittent resources, such as wind generation and solar generation contribute less than their full nameplate generating capacity toward meeting SPS's planning reserve margin requirement due to their variability. The current accredited capacity SPS assumed for each resource type is shown below in Table 6-6. The Southwest Power Pool determines the methodology that is used to determine the amount of renewable capacity that can be applied to SPS's planning reserve requirement. Beginning summer of 2023, Southwest Power Pool will replace the current renewable accreditation methodology with the Effective Load Carrying Capability ("ELCC") methodology. The Southwest Power Pool will also apply the ELCC methodology to energy storage resources in the future. The ELCC methodology will result in decreasing accreditation of renewable resources and energy storage resources as the penetration of those resources increase across the Southwest Power Pool Balancing Authority Area. As SPS is unable to determine the future penetration of renewable resources and energy resources across the Southwest Power Pool Balancing Authority Area, when determining the most cost-effective portfolio of resources, SPS did not incorporate diminishing accredited capacity for generic solar, wind, and BESS resources.

Table 6-4: Accredited Capacity for New Resources

Summer Accredited Capacity for Generic Resources	
Generic Solar	58.00%
Generic Wind	19.90%
Generic CTG	100.00%
Generic CC	100.00%
Generic BESS	100.00%

Lead Time for New Resources

Development and subsequent construction of new generation facilities can take several years to complete, depending on the public and regulatory environment for which the resource is planned. SPS's recent experience has shown the regulatory approval process for new resources can exceed 12 months – excluding a competitive procurement process that can add a further six to nine months. Development of resources can take anywhere from 1 year to multiple years depending on the resource, such as renewable energy, where thousands of acres of land are required to be secured for development. Finally, engineering, procurement, construction, startup, and commissioning of new facilities can take anywhere from two to three years. Although most of the processes are scheduled to occur strategically in parallel, that is, concurrently, especially development and other "at-risk" engineering and planning, the best case execution of these tasks from start to finish would result in a resource coming online within approximately two to four years from start to finish. These public and regulatory details must be strategically accounted for when planning and executing the installation of new resources, including the lead times for critical equipment manufacturing and delivery to sites. Other factors such as current lead times for interconnection agreements detailed in Section 7.07 also add an additional level of schedule uncertainty and risk that must be considered in the overall schedule.

6.05 - 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.[22]

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 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; thus, mitigating the need for new resources over time.

TOU Rates

Time of Use ("TOU") rates are available as an option for all general service customers, except Large General Service – Transmission. 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

---

[22] SPS's current rates were set in Case No. 19-00170-UT. The rates are subject to revision in Case No. 20-00238-UT.

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.

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.

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 resources available for selection in the model are described in more detail in Section 6.

The computer model 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.

While this model is a powerful tool that can be used to generate and evaluate thousands of possible resource portfolios, the sheer complexity of 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.

7.02 - EnCompass Production Cost Model

SPS recently transitioned to the EnCompass production cost model in its resource planning process. EnCompass is a production costing model that uses an algorithm to determine the most cost-effective resource portfolio for a utility system from a prescribed set of resource technologies under given sets of constraints and assumptions. The EnCompass model includes: 1) a modern "solve anything" algorithm; 2) hourly operation detail that can accurately capture ramp rates, start-up, etc.; and 3) enhanced storage logic and ancillary services. EnCompass is also able to perform utility capital accounting (revenue requirements).

In addition to the usual input variables needed for a production costing model, EnCompass incorporates a wide variety of resources expansion planning parameters to develop a coordinated, integrated plan that best suits the utility system being analyzed. For example, EnCompass incorporates resource expansion planning parameters such as: alternative generation technologies available to meet future needs; renewable energy resources; unit capacity sizes; heat rates; LM; conservation programs; reliability limits; and environmental compliance options.

Costs Included in EnCompass

The EnCompass model includes the critical generation costs SPS incurs to provide electric service to its customers. The following lists summarize the costs that are typically included in the EnCompass model.

1. Fuel costs for all electric power supply resources (owned and purchased) and market energy costs (which are forecasted based on gas prices;
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. Energy costs for new wind and solar generation facilities added to meet future energy need;
7. Electric transmission interconnection and network upgrade cost for new generation;
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.

7.03 - Development of Resources Portfolios

The following factors were considered in, or affected, the development of the most cost-effective portfolio of resources and alternative portfolios.

System reliability and planning reserve margin requirements

Maintaining system reliability and planning reserve margin requirements is a critical modeling constraint when developing resource portfolios. The EnCompass model was constrained to maintain at a minimum Southwest Power Pool's 12% planning reserve margin on a monthly basis. Failure to meet the planning reserve margin resulted in the EnCompass model adding new capacity resources. The EnCompass model evaluated the ability of the resource portfolio to meet electric demand on an hourly basis. However, rather than program a hard constraint, SPS assigned an extremely high emergency energy cost ($/MWh) in hours where SPS's resources and market energy purchases could not meet hourly demand. This high cost ensured EnCompass would add additional resources if SPS could not regularly meet hourly demand, but also prevented the model from adding new resources whenever the emergency energy need was extremely small.

Renewable Energy Portfolio Requirements

As demonstrated in New Mexico Case No. 21-00172-UT, SPS is projecting continued compliance with the RPS throughout the Action Plan. During the Planning Period, New Mexico's RPS requirement is scheduled to increase to 80% of NM retail sales. Modeling long-term compliance with the RPS is challenging for multi-jurisdiction utilities, such as SPS, that must plan resources on a total system basis, not a jurisdictional basis. New Mexico retail sales represent approximately 35% - 40% of SPS's total system sales. Therefore, without knowing exactly how RPS compliant resources will be allocated between jurisdictions, it is challenging to determine exactly the quantity of renewable resources required to meet 80% New Mexico retail sales. Therefore, SPS did not constrain the resource portfolios to meet the NM RPS; however, SPS did retrospectively evaluate the resource portfolios to ensure compliance through the planning period is achievable. SPS's most cost-effective portfolio of resources includes renewable resources generating approximately 82% of the total system wide sales in 2040.

Load Management and Energy Efficiency Programs

SPS's base, low and high energy and demand forecasts are net of projected load management and energy efficiency programs. Therefore, load management and energy efficiency programs were directly incorporated into the load forecasts SPS used when developing the resource portfolios.

Existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions.

In developing the most cost-effective portfolio of resources and alternative portfolios, SPS evaluated compliance with all existing environmental law and regulations. SPS did not evaluate the effect of anticipated or possible future environmental regulations (that is neither the subject of a proposed or final rulemaking) because they are speculative and may never be adopted, or they may be adopted in some different form than the proposal. The one exception being the standardized cost of carbon emissions that is included in the analyses, which is described in more detail in Section 7.13.

A summary of the current status and remaining unknowns about each environmental regulation, along with the potential impacts on SPS's generation resources is included in Appendix K.

Fuel Diversity

It is difficult to directly quantify the value of fuel diversity when determining resource portfolios; therefore, SPS did not directly assign a quantitative fuel diversity benefit as a direct input or factor. However, SPS recognizes the importance of the reliability and economic benefits of fuel diversity. Outside of the EnCompass analysis, SPS considers the benefits of fuel diversity in its resource planning decisions. For example, fuel diversity is an additional benefit of maintaining the Tolk Units through 2032.

Susceptibility to fuel interdependencies

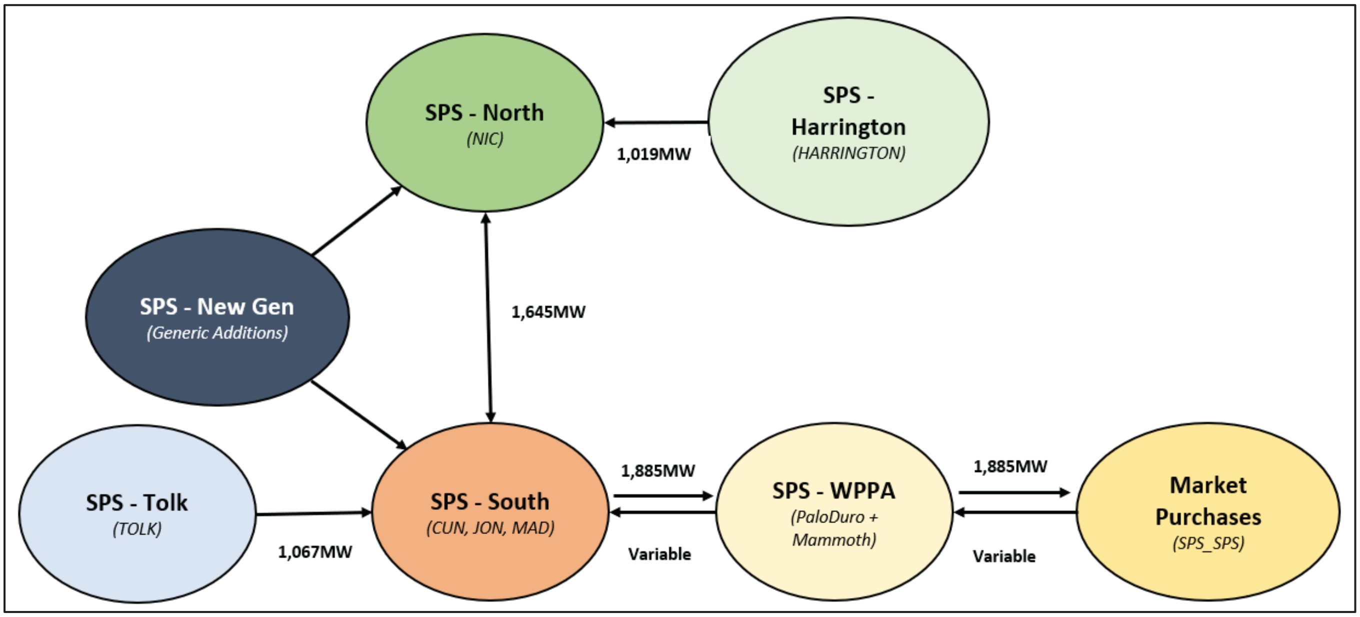
EnCompass provides hourly operation detail that can accurately capture ramp rates, start-up times, minimum up and minimum down times, and other factors. Therefore, EnCompass determines how different technologies (and fuel types) interact with one another when calculating the most cost-effective portfolio of resources and alternative portfolios.

Transmission Constraints

SPS included two major transmission constraints in the EnCompass model. First, as described in Section 3.09, Southwest Power Pool has a total of 1,885 MW of transmission flow capability minus the single largest contingency and other factors (i.e., imports from Palo Duro and Mammoth Wind) to deliver resources to the SPS zone from the rest of the Southwest Power Pool transmission system. Second, SPS's analysis included a 1,645 MW North to South constraint. New Generation was not subjected to the North to South constraint.

In addition to the transmission constraints, SPS included generator point of injection constraints between Harrington and Tolk and the SPS system. In the event resources are selected at Tolk and/or Harrington and SPS exercised its rights to use replacement or surplus interconnection capacity, these constraints ensured neither facility could exceed its current maximum capability. For example, in the event a new wind generator was co-located at Tolk, the total output of the existing Tolk Generators and the new wind facility could still not exceed 1,067 MW.

Figure 7F.0: EnCompass Transmission Constraints



7.04 - Establishing a Base Case Analysis in EnCompass

When establishing the most cost-effective portfolio of resources in EnCompass, SPS first determined the critical inputs and assumptions to be used for its base case analysis. The base case analysis incorporates the following critical inputs and assumptions:

- Base natural gas and market energy forecast (see section 7.10)
- Base load forecast (see Section 7.11)
- Mid-point transmission network upgrade costs (see section 7.12)
- $0 social cost of carbon (see section 7.13)

SPS's base case analysis assumed specific dates for the retirement of SPS generation consistent with Table 3-1 (see Section 3, above). SPS also considered alternative retirement dates for the Tolk Units and the Harrington Units, which are presented in the alternative portfolios section below.

7.05 - Based Case - Resource Need

Action Plan Period

As shown in Table 5-2, SPS has enough supply-side resources to meet its planning reserve margin requirement until the Summer of 2031. Also, as demonstrated in SPS's New Mexico 2021 RPS filing, Case No. 21-00172-UT, SPS anticipates continued RPS compliance beyond the Action Plan Period. Therefore, SPS does not need any additional resources to reliably serve its customers or meet regulatory requirements during the Action Plan. However, even without a defined resource need, SPS may still pursue additional resources if such resources are reasonably expected to provide other benefits, such as economic energy savings. When deciding whether to acquire economic energy resources, SPS must consider the likelihood that the economic resources will provide the energy savings anticipated.

Planning Period

Over the next 10-years, several of SPS's older gas steam units are scheduled to retire, creating a 174 MW capacity need by the Summer of 2031. SPS's capacity need then increases significantly over the remainder of the 20-year Planning Period as existing generating units retire and PPAs expire. For example, during the planning period, SPS's two largest plants, Tolk and Harrington, are scheduled to retire as is the remainder of the gas steam generating units and the Lea Power combined cycle PPA is also scheduled to expire. By the end of the Planning Period, SPS's capacity need is expected to grow to 4,194 MW.

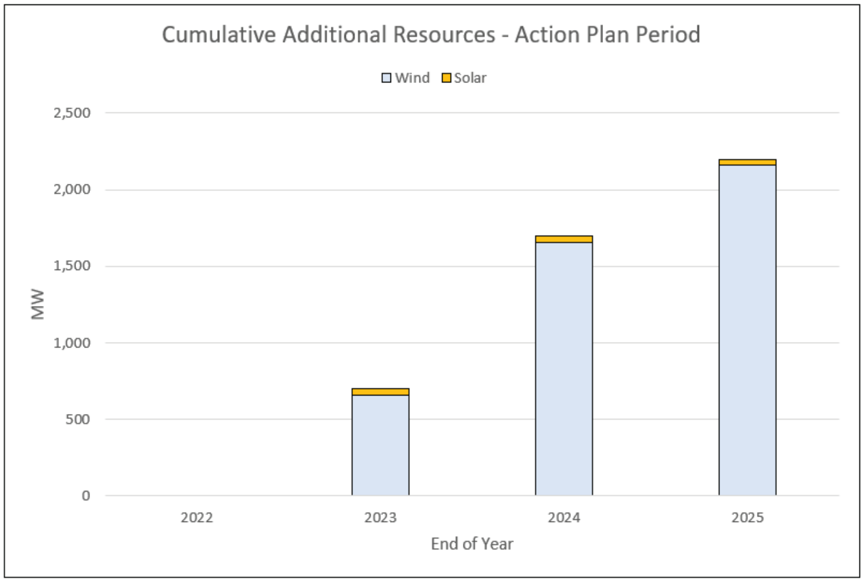
7.06 - Most Cost-Effective Resource Portfolio – Base Case

Action Plan Period

As described above, over the course of the 4-year Action Plan Period, SPS does not require any new resources for reliability needs or regulatory requirements. However, SPS may pursue additional economic energy resources. As shown below in figure 7F.1, SPS's most cost-effective resource portfolio includes an additional 2,158 MW of economic wind generation and 40 MW of economic solar generation added during the Action Plan Period.

Although the most cost-effective resource portfolio includes additional economic energy resources, SPS must consider risks and uncertainties when procuring economic energy resources. Risks and uncertainties are discussed in detail in the Tolk Analysis and summarized below in Section 7.07.

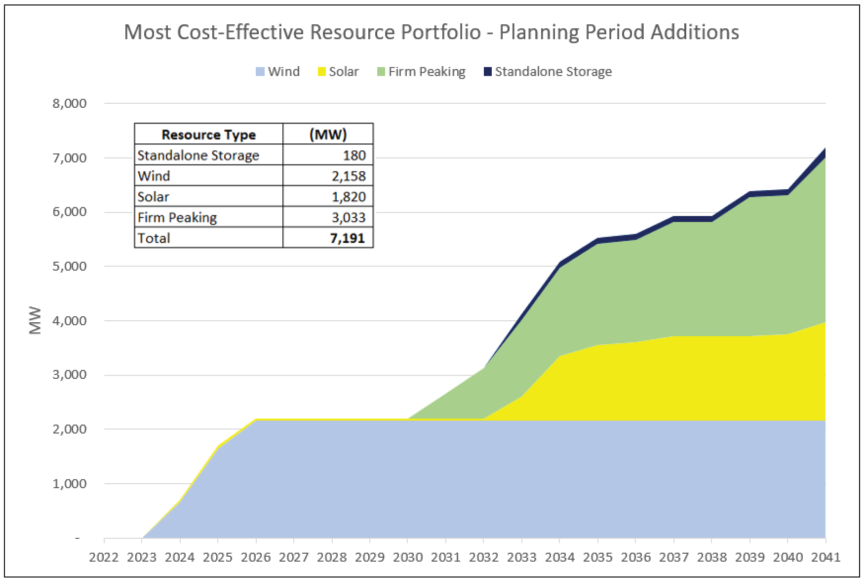
Figure 7F.1: Most Cost-Effective Resource Portfolio – Additional Resources During the Action Plan



Planning Period

As discussed above in Section 7.05, SPS's capacity need is expected to grow from 174 MW in 2031 to 4,194 MW in 2041. While renewable generation, particularly solar, can meet some of this capacity need, SPS will also need firm and dispatchable resources to serve load when intermittent renewable resources are unavailable. Based on SPS's growing capacity need, as shown in Figure 7F.2, it is not surprising that SPS's most cost-effective resource portfolio includes 1,780 MW of new solar generation, 180 MW of BESS, and approximately 3,000 MW of new CTGs over the Planning Period – in addition to the resources added during the Action Plan. Environmental mandates, such as New Mexico's RPS, or technological and/or economic improvements of emerging technologies may drive the need for the CTGs to switch to carbon-free hydrogen as a fuel source, or ultimately replace the combustion turbines with other technologies, such as long-duration energy storage or other technologies that are not currently commercially viable. SPS's most cost-effective portfolio of resources does not require any new CTGs until 2031, providing SPS time to re-evaluate alternative carbon-free fuel sources, or technological alternatives to CTGs, as the next generation of carbon-free technologies mature. SPS believes the development of carbon-free fuel sources and/or the advancement of technologies not currently commercially viable will be essential in achieving the 2045 carbon free goal specified in the Energy Transition Act.

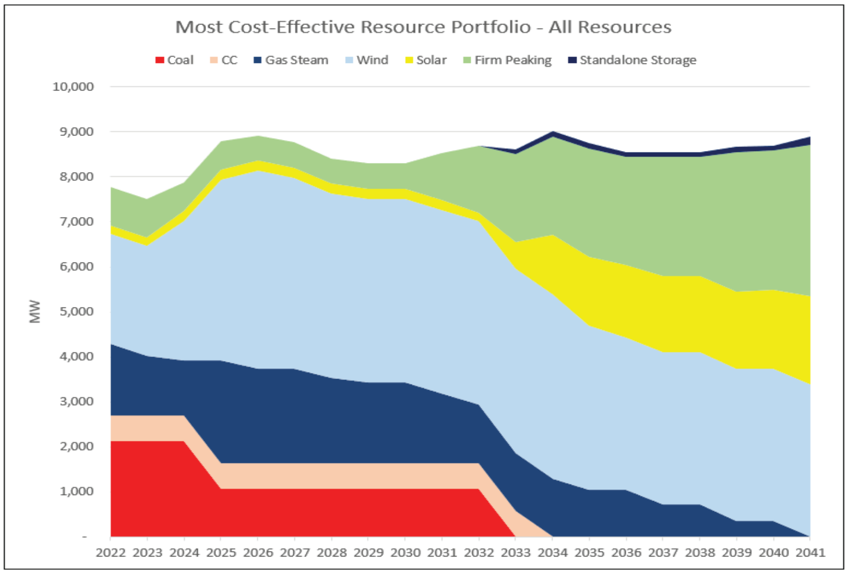
Figure 7F.2: Most Cost-Effective Resource Portfolio –Additional Resources During the Planning Period



Resource Type	(MW)
Standalone Storage	180
Wind	2,158
Solar	1,820
Firm Peaking	3,033
Total	**7,191**

SPS's most cost-effective resource portfolio will experience an unprecedented transition over the next two decades. As shown below in Figure 7F.3, SPS's entire coal-fired generation will either be retired or converted to operate on natural gas before the end of 2032 and all units that burn coal today will be retired before the end of the Planning Period. SPS's entire gas-steam generating fleet is also scheduled to retire before the end of the Planning Period, as is the Lea Power combined cycle. In its place, SPS's 2041 most-cost effective resource portfolio is projected to include 3.4 GW of wind generation, nearly 2 GW of solar generation, 180 MW of BESS and 3.4 GW of firm peaking generation. Again, while current modeling inputs and assumptions show CTGs providing firm peaking and load-following generation, this will likely change as the cost of emerging technologies continue to trend down.

Figure 7F.3: Most Cost-Effective Resource Portfolio – Planning Period All Resources



7.07 - Uncertainty in Modeling the Cost of New Resources

While there is inherent uncertainty in modeling the cost of generating resources up to 20-years in advance, SPS's 2021 IRP has been prepared during a period of heightened uncertainty that impacts the cost of resources in the near and long term. Uncertainties, such as the possible extension of renewable tax credits and the high cost of transmission network upgrades can, and most likely will fundamentally change SPS's most cost-effective resource portfolios over the 4-year Action Plan and 20-year Planning Period. These uncertainties are discussed in detail in the Tolk Analysis and summarized below.

Extension of Federal Tax Credits

For the purposes of determining the most cost-effective portfolio of resources, SPS assumed wind production tax credits and solar investment tax credits would expire or step-down based on the currently approved schedule. However, at the federal level, several bills that could extend or revise renewable tax credits are currently being considered. If passed, the extension of renewable tax credits would likely fundamentally change SPS's most cost-effective resource portfolio. For example, as demonstrated above in figure 7F.2, the currently scheduled EOY 2025 expiration of wind production tax credits have a significant impact on the timing of future wind acquisitions. SPS's most cost-effective portfolio of resources includes 2,158 MW of new PTC qualifying wind generation before the end EOY 2025 and then no additional wind generation after the PTCs expire. An extension of PTCs will (1) potentially defer the acquisition of wind generation during the Action Period and (2) likely add additional wind resources not currently seen in the Planning Period. Additional wind generation during the Planning Period may mitigate the need for some, but not all, firm peaking generation in the future.

Transmission Network Upgrade Costs and Schedule Uncertainty

The acquisition of new generating resources within SPS's service territory is subject to Southwest Power Pool's severely backlogged transmission interconnection study process – with new requests taking several years to be completed. Furthermore, when the results of the transmission network upgrade studies are identified, they often result in proposed generators being assigned cost-prohibitive transmission network upgrades, for example the DISIS 2017-01 2nd Phase Study assigned $934/kW to new generators in SPS's service territory. In comparison, the cost to construct a new solar facility excluding transmission network upgrades is estimated to be approximately $1,000/kW - $1,200/kW. Currently, it is challenging to anticipate and evaluate the cost of network upgrades in the near- and long-term future. Furthermore, it is uncertain whether projects will actually proceed once transmission network upgrade costs are known. For example, the DISIS 2017-01 study initially contained nearly 3,800 MW of new renewable generation in SPS's service territory. After Southwest Power Pool required each proposed project to submit a 20% deposit only a single 200 MW wind generating facility remained. As discussed in more detail in Section 6 and in the Tolk Analysis, in the base case analysis, SPS assumed generators requiring a new generator interconnection agreement would be assigned $400/kW for transmission network upgrades (less than half of the amount assigned in the 2017-01 DISIS). As described later in this section, SPS also conducted sensitivity analyses for the cost of transmission network upgrades. SPS did not assign additional transmission network upgrade costs to RFI proposals that either (1) already possessed an executed generator interconnect agreement, or (2) build-transfer proposals that interconnected at the site of existing SPS generators. SPS assumed the latter would provide the opportunity for SPS to exercise its rights for replacement or surplus interconnection rules to avoid the need for a new generator interconnection agreement. SPS assigned the same additional transmission network upgrade costs to all future generic CC, wind, and solar resources. SPS did not assign additional transmission network upgrade costs for generic CTGs or BESS resources, on the assumption the resources would be located at the site of existing generation.

In addition, as described in Section 6, SPS modeled the commercial operation dates of the proposals submitted in the RFI. These proposals included projects that have subsequently withdrawn from the 2017-01 DISIS and proposals that have not yet entered Southwest Power Pool's study process.

Emerging and Future Technologies

Technological and economic improvements of 'emerging technologies', such as solar and battery energy storage, will continue to redefine SPS's resource portfolio over the 20-year Planning Period. In addition, the next generation of technologies such as hydrogen capable generation or long-duration energy storage will become increasing important as SPS and New Mexico work together towards decarbonizing the power sector. For the purposes of determining the most-effective portfolio of resources, SPS used the pricing for the resource options described in Section 6 in developing the base case analysis.

7.08 - Alternative Portfolios / Mitigating Ratepayer Risk

To mitigate ratepayer risk, SPS evaluated alternative portfolios (sensitivities) assuming changes to critical modeling inputs, such as: the future operation and retirement dates of SPS's existing coal generation, natural gas price forecast, market energy price forecast, and load forecast. In addition, due to the uncertainty in transmission network upgrade cost described above, SPS also conducted sensitivity analyses for transmission network upgrade costs. Each of the sensitivity analyses are described in more detail in the Tolk Analysis. Finally, as described in Section 7.13, SPS also evaluated three different carbon price sensitivity analyses. In addition to the sensitivity analyses described throughout the remainder of this section, SPS also evaluated multi-factor sensitivity analyses, such as low load and low natural gas price forecasts. The results of these analyses are provided in Appendix J.

7.09 - Future Operation of SPS's existing coal generation

SPS's two largest plants, Tolk Station and Harrington Station, both face unique operational challenges. The coal-fired Tolk Units, rely upon water from the Ogallala Aquifer for generation and cooling, and the aquifer is in irreversible decline. The limited availability of economic water necessitates either: (1) the conservation of water through reduced / seasonal operations or (2) the early retirement of both units. SPS's other coal plant, Harrington Station, is subject to an agreed order with the TCEQ to cease burning coal at the end of 2024, at which point all three units will be converted to operate on natural gas.

Tolk Operation and Retirement Analysis

Per the uncontested comprehensive stipulation in New Mexico Case No. 19-00170-UT, SPS's 2021 IRP includes an updated "Tolk Analysis" evaluating the optimal retirement date of the Tolk Units. The Tolk Analysis continues to support seasonal / summer operations of the Tolk Units and a 2032 retirement date for both units. The Tolk Analysis is included in its entirety in Appendix H and was previously filed with the NMPRC in June 2021.

Harrington Operation and Retirement Analysis

In New Mexico base rate Case No. 20-00238-UT, SPS presented its analysis supporting the October 2020 agreed order with the TCEQ to cease burning coal at the end of 2024. SPS intends to file a Certificate of Public Convenience and Necessity in New Mexico soon after the filing of this IRP supporting the decision to the convert the units to operate on natural gas. A summary of this analysis is presented in Appendix I.

7.10 - Natural Gas & Market Energy Price Forecast

The price of natural gas is an important variable. SPS uses a combination of market prices and fundamental price forecasts, based on multiple highly respected, industry leading sources, to calculate monthly delivered gas prices. As the foundation of the gas price forecast, Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange ("NYMEX") futures prices) and long-term fundamentally based forecasts from Wood Mackenzie, IHS Energy, and S&P Global. The forecast is fully market-based for the current year plus two additional years and then transitions into blending the four sources to develop a composite forecast. The Henry Hub forecast is adjusted for regional basis differentials and specific delivery costs for each generating unit to develop final model inputs.

SPS conducted low and high natural gas price forecast sensitivity analyses. 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. SPS's market price forecast is dependent on the gas price forecast used. As such, the market price forecast was adjusted with the low and high gas sensitivity analyses.

SPS's base, low and high natural gas and market energy forecast for the years 2022 – 2041 are shown in Appendix G (oil and coal price forecasts are also included in Appendix G).

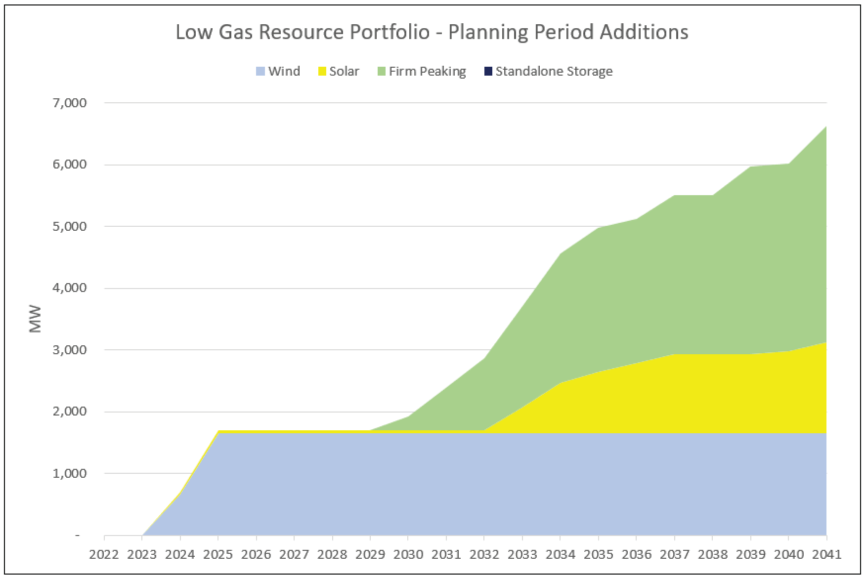
Low Forecast

The low natural gas and market energy price sensitivity analysis resulted in the acquisition of similar resources during the Planning Period – notably, wind, solar and CTGs. However, as shown in Table 7.1 and Figure 7F.4 below, when compared to the base case analysis, the low natural gas and market energy price sensitivity acquired two additional CTGs at the expense of 500 MW less wind and 350 MW less solar generation. The low natural gas and market energy price sensitivity did not add any standalone BESS projects during the Planning Period.

Table 7.1: Low Natural Gas & Market Energy Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	-	(180)
Solar + Storage	-	-	-
Wind	2,158	1,658	(500)
Solar	1,820	1,470	(350)
Firm Peaking	3,033	3,500	467
CC	-	-	-
Total	**7,191**	**6,628**	**(563)**

Figure 7F.4: Low Natural Gas and Market Energy Forecast – Additional Resources During the Planning Period



High Forecast

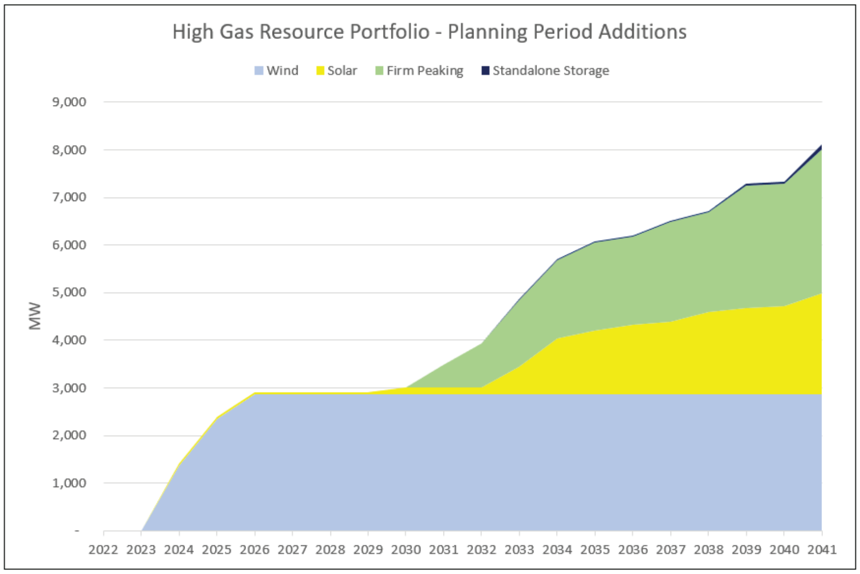
Again, the high natural gas and market energy price sensitivity analysis resulted in the acquisition of similar resources during the Planning Period – notably, wind, solar, and CTGs. However, as shown in Table 7.2 and Figure 7F.5 below, when compared to the base case analysis, the high natural gas and market energy price sensitivity acquired an additional 700 MW of wind and

310 MW of additional solar. The high natural gas and market energy price sensitivity acquired 100 MW of BESS – 80 MW less than the base case analysis.

Table 7.2: Low Natural Gas & Market Energy Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	100	(80)
Solar + Storage	-	-	-
Wind	2,158	2,858	700
Solar	1,820	2,130	310
Firm Peaking	3,033	3,033	-
CC	-	-	-
Total	**7,191**	**8,121**	**930**

Figure 7F.5: High Natural Gas and Market Energy Forecast – Additional Resources During the Planning Period



7.11 - Load Forecast

Demand and energy forecasts are another important variable. As such, SPS conducted low and high load forecast sensitivity analyses using the methodology described in section 4. However, it is worth noting, the methodology described in Section 4 for calculating the 'base' load case forecast is largely used for financial planning purposes. Despite continued growth in oil and gas developments in the New Mexico portion of the Permian basin and due to the volatility of the industry, the financial load forecast incorporates only a modest amount of projected oil and gas load growth. The 'high' load case forecast represents a more accurate projection of SPS's capacity position if oil and gas load continue to increase. For the purposes of resource planning, the high load forecast is predominately used to ensure SPS has enough resources to reliably serve customers.

SPS's base, low, and high load forecast for the years 2022 – 2041 are shown in Appendix G.

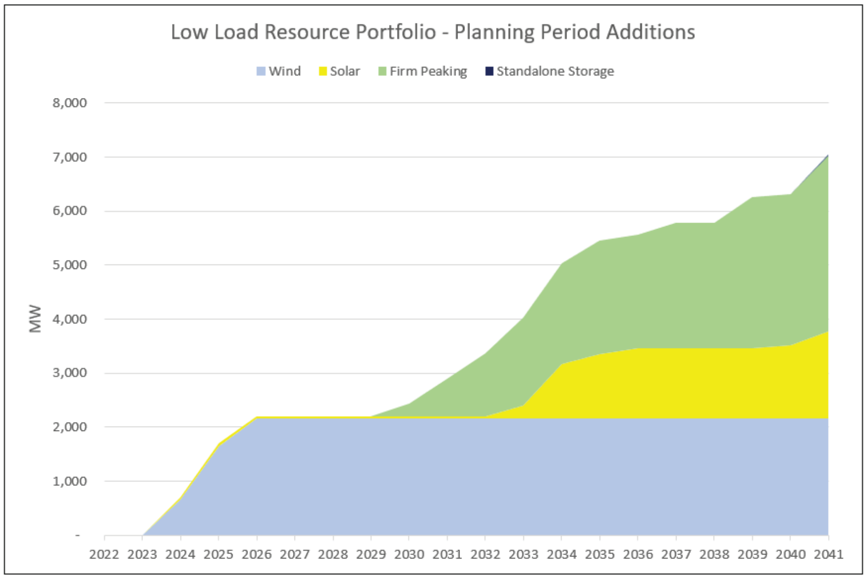
Low Load Forecast

As shown below in Table 7.3 and Figure 7F.6, during the Planning Period, the low load forecast resource portfolio added the new wind generating resources as the base case. The low load forecast resource portfolio added an additional CTG during the planning period at the expense of 170 MW less BESS and 210 MW less solar generation.

Table 7.3: Low Load Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	10	(170)
Solar + Storage	-	-	-
Wind	2,158	2,158	-
Solar	1,820	1,610	(210)
Firm Peaking	3,033	3,266	233
CC	-	-	-
Total	**7,191**	**7,044**	**(147)**

Figure 7F.6: Low Load Forecast – Additional Resources During the Planning Period



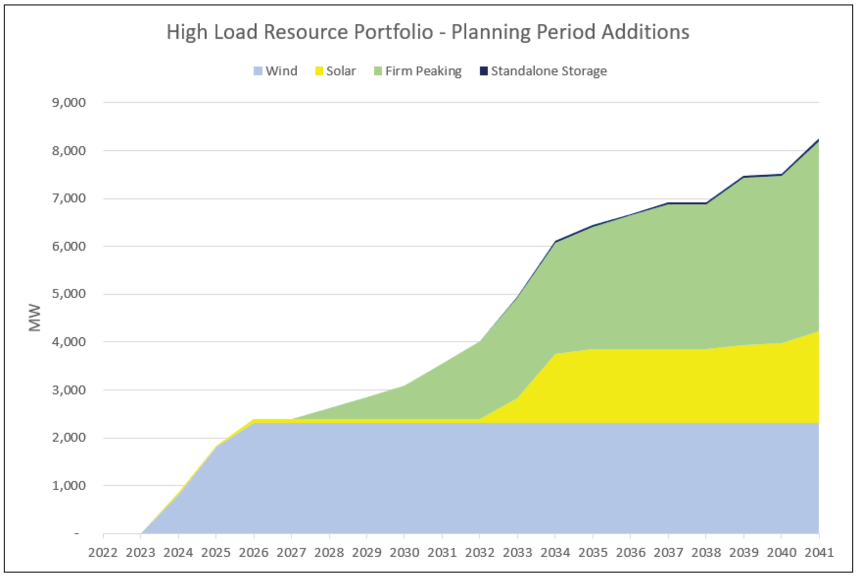
High Load Forecast

As shown below in Table 7.4 and Figure 7F.7, during the Planning Period, the high load forecast resource portfolio added an additional 150 MW of wind, 100 MW of solar and 4 additional CTGs. The high load forecast resource portfolio added 170 MW less BESS than the base case.

Table 7.4: High Load Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	60	(120)
Solar + Storage	-	-	-
Wind	2,158	2,308	150
Solar	1,820	1,920	100
Firm Peaking	3,033	3,966	933
CC	-	-	-
Total	**7,191**	**8,254**	**1,063**

Figure 7F.7: High Load Forecast – Additional Resources During the Planning Period



7.12 - Transmission Network Upgrades

As described in Section 7.07, due to the current high uncertainty in transmission network upgrade costs, SPS evaluated alternative portfolios using two alternative transmission network upgrade costs: $200/kW and $400/kW.

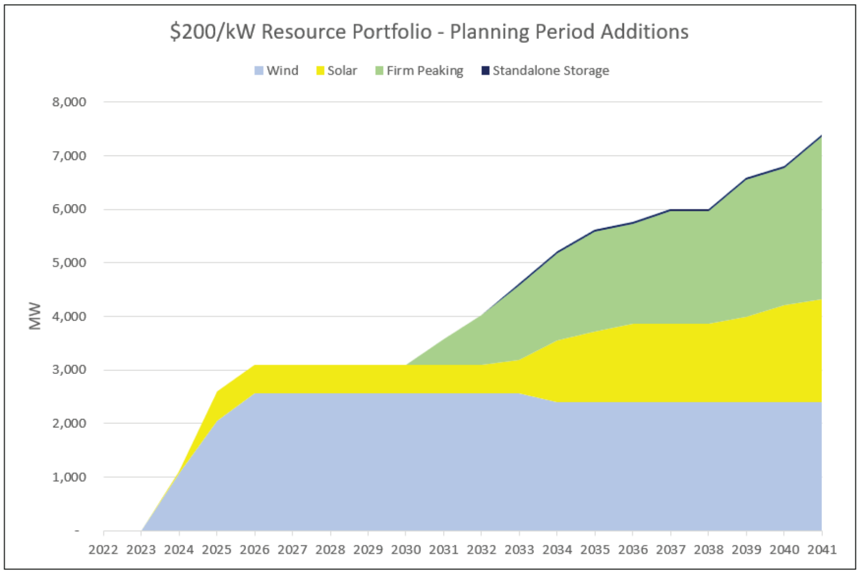
$200/kW Transmission Network Upgrades Costs

As shown below in Table 7.5 and Figure 7F.8, during the Planning Period, the $200/kW resource portfolio added an additional 251 MW of wind and 90 MW of additional solar. The $200/kW resource portfolio added the same amount of CTGs as the base case and 130 MW less BESS than the base case.

Table 7.5: $200/kW Transmission Network Upgrade Costs – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	50	(130)
Solar + Storage	-	-	-
Wind	2,158	2,409	251
Solar	1,820	1,910	90
Firm Peaking	3,033	3,033	-
CC	-	-	-
Total	**7,191**	**7,402**	**211**

Figure 7F.8: $200/kW Transmission Network Upgrades – Additional Resources During the Planning Period



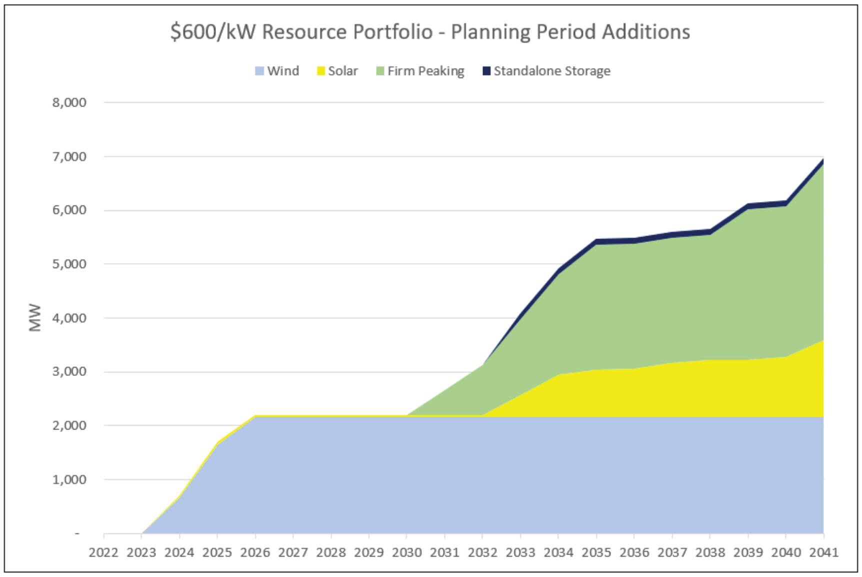
$600/kW Transmission Network Upgrade Costs

As shown below in Table 7.6 and Figure 7F.9, during the Planning Period, the $600/kW resource portfolio added an additional CTG. The $600/kW resource portfolio added the same amount of wind generation as the base case and 380 MW less solar 70 MW less BESS than the base case.

Table 7.6: $600/kW Transmission Network Upgrade Costs – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	110	(70)
Solar + Storage	-	-	-
Wind	2,158	2,158	-
Solar	1,820	1,440	(380)
Firm Peaking	3,033	3,266	233
CC	-	-	-
Total	**7,191**	**6,974**	**(217)**

Figure 7F.9: $600/kW Transmission Network Upgrades – Additional Resources During the Planning Period



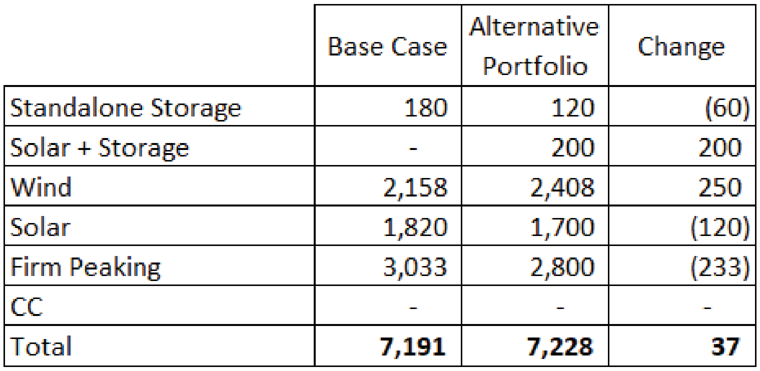
7.13 - Carbon Price Sensitivity

In addition to the alternative portfolios described in the Tolk Analysis, SPS also conducted a carbon price sensitivity analysis. 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*).

$8 per metric ton

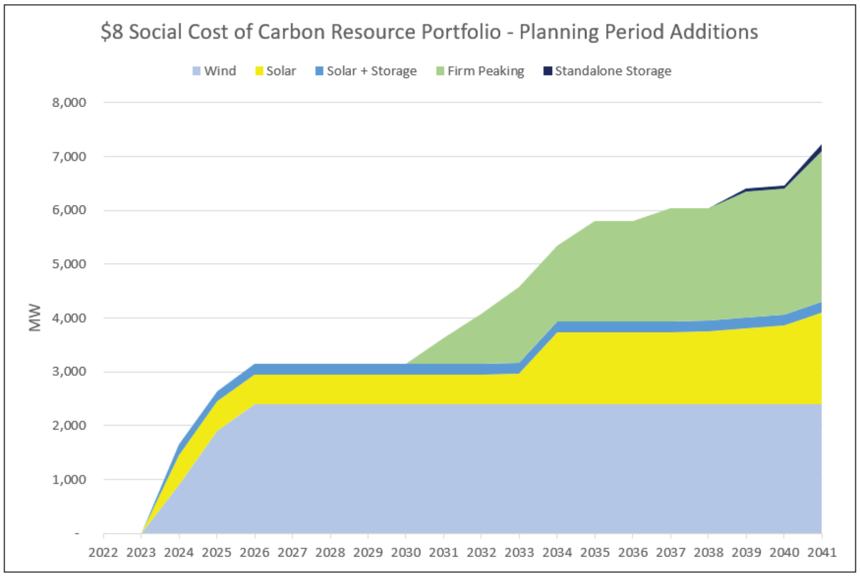
As shown below in Table 7.7 and Figure 7F.10, during the Planning Period, the $8 per metric ton social cost of carbon resource portfolio added an additional 250 MW of wind and 200 MW of additional solar + BESS. The $8 per metric ton social cost of carbon resource portfolio added one less CTG, 60 MW less standalone BESS, and 120 MW less solar as the base case.

Table 7.7: $8 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period



	Base Case	Alternative Portfolio	Change
Standalone Storage	180	120	(60)
Solar + Storage	-	200	200
Wind	2,158	2,408	250
Solar	1,820	1,700	(120)
Firm Peaking	3,033	2,800	(233)
CC	-	-	-
Total	**7,191**	**7,228**	**37**

Figure 7F.10: $8 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period



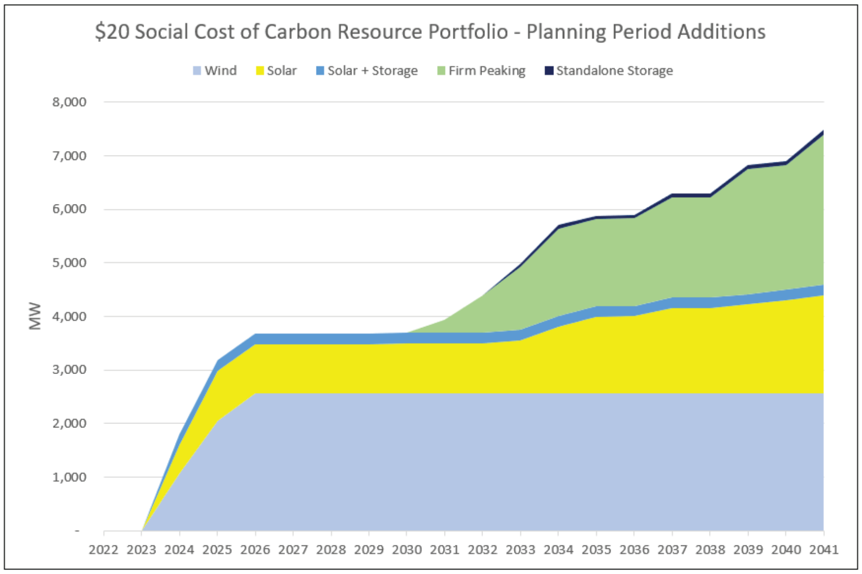
$20 per metric ton

As shown below in Table 7.8 and Figure 7F.11, during the Planning Period, the $20 per metric ton social cost of carbon resource portfolio added an additional 400 MW of wind, 15 MW of additional solar, and 200 MW of additional solar + BESS. The $8 per metric ton social cost of carbon resource portfolio added one less CTG and 90 MW less standalone BESS.

Table 7.8: $20 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	90	(90)
Solar + Storage	-	200	200
Wind	2,158	2,558	400
Solar	1,820	1,835	15
Firm Peaking	3,033	2,800	(233)
CC	-	-	-
Total	**7,191**	**7,483**	**292**

Figure 7F.11: $20 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period



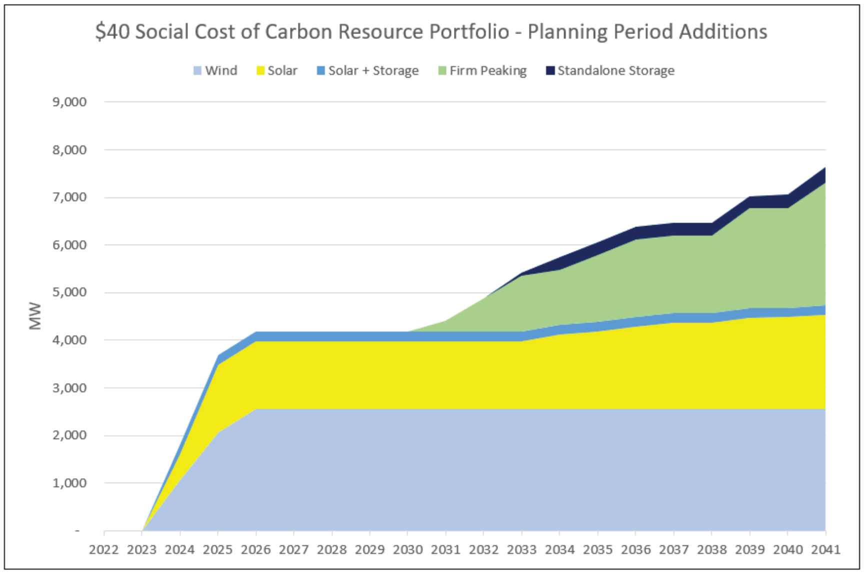
$40 per metric ton

As shown below in Table 7.8 and Figure 7F.11, during the Planning Period, the $20 per metric ton social cost of carbon resource portfolio added an additional 400 MW of wind, 165 MW of additional solar, 150 MW of additional BES, and 200 MW of additional solar + BESS. The $40 per metric ton social cost of carbon resource portfolio added two less CTGs.

Table 7.9: $40 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	330	150
Solar + Storage	-	200	200
Wind	2,158	2,558	400
Solar	1,820	1,985	165
Firm Peaking	3,033	2,566	(467)
CC	-	-	-
Total	**7,191**	**7,639**	**448**

Figure 7F.12: $40 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period



7.14 - Conclusion

The most cost-effective portfolio of resources and each of the alternative portfolios evaluated include a similar portfolio of resources at the end of the Planning Period. First, each portfolio adds a significant amount of new wind generation during the action plan period to take advantage of the currently scheduled-to-expire PTCs. After the PTCs are scheduled to expire, little-to-no additional wind is added in each of the portfolios. The possible extension of PTCs will fundamentally change the timing and extent of future wind acquisitions.

Looking further ahead, each portfolio comprises of additional solar generation, CTG's and to a lesser extent, BESS, to meet SPS's growing capacity need. As SPS transitions to a more renewable heavy portfolio mix and existing thermal resources retire, SPS's need for firm and dispatchable energy will increase. Currently, this need is fulfilled with CTGs, however, as emerging technologies continue to mature, these CTGs may be replaced with long duration battery energy storage or other technologies that are not currently commercially viable.

Section 8. PUBLIC ADVISORY PROCESS AND TECHNICAL CONFERENCES

Pursuant to the IRP Rule (17.7.3.9.H NMAC), SPS was required to begin planning for the 2021 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 May 21, 2020, were sent and published a minimum of 30 days prior to the first meeting. 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 April 8, 2020, 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 mid-March through mid-April 2020 billing period. Copies of the invitation, public notice, and bill insert are included in Appendix L.

Pursuant to the uncontested comprehensive stipulation in Case No. 19-00170-UT (SPS's 2019 New Mexico Rate Case), SPS was required to host a series of Technical Conferences. SPS actively sought feedback from interested parties throughout the Tolk Analysis by hosting a series of 'Technical Conferences' specific to the Tolk Analysis in addition to and in parallel with SPS's 2021 IRP Public Advisory Process.

Before each Public Advisory meeting and technical conference, SPS provided adequate notice and an agenda of topics to be discussed. SPS experienced medium to high public participation at

Public Advisory meetings and technical conferences. Commonly, attendance included members from Staff, numerous renewable energy developers, several environmental agency representatives, and other energy industry representatives (i.e., oil and gas producers, electric cooperatives, consulting companies, renewable energy service providers). SPS either responded to or followed-up on multiple questions from participants throughout the Public Advisory Process and technical conferences.

Public Advisory meetings and Technical Conferences were held over an approximate12-month time frame. Due to the COVID 19 pandemic, all Public Advisory meetings and Technical Conferences were conducted via video and telephone conferences. A complete list of each Technical Conference and all contents presented at each of the Technical Conferences can be found in Appendix H. In addition, 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 M.

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

Meeting Date	Topics Discussed
May 21, 2020	Xcel Energy and SPS System Overview Resource Planning Overview Factors Impacting Resource Planning Since 2018 NM IRP Factors That Will Likely Influence Resource Planning Over the Action Plan Period SPS's New Renewable Wind Facilities
August 20, 2020	Emerging Environmental Impacts for SPS Harrington NAAQS[23] Compliance
January 12, 2021	Introduction to the New Mexico Integrated Resource Plan NM Energy Efficiency and Load Management Programs

---

[23] National Ambient Air Quality Standards

	Sales and Load Forecasting
March 23, 2021	Coal Supply Tolk Station Water Supply Gas & Power Market Price Forecasting
May 13, 2021	Energy Storage Generator Interconnection Agreement Issues

Section 9. ACTION PLAN

9.01 - SPS Action Plan for 2022-2025

SPS has adequate generating capacity to meet its planning reserve margin over the Action Plan 2022-2025. Furthermore, as demonstrated in SPS's most recent RPS filing (Case No. 21-00172-UT), SPS anticipates continued RPS compliance throughout the Action Plan. Therefore, SPS does not need to procure additional resources to reliably serve its customers or meet regulatory requirements under 17.9.572 NMAC during the Action Plan. However, even without a defined resource need, SPS may still pursue additional resources if they are expected to provide additional benefits, such as economic energy savings. Results from SPS's recent RFI indicate the acquisition of additional wind resources within the Action Plan may provide economic energy savings; however, these savings are highly dependent on the expiration of PTCs and uncertain transmission network upgrade costs. Furthermore, SPS has subsequently learned that several proposals received in the RFI are no longer viable projects. As such, SPS is not proposing any new resources in the Action Plan, instead SPS is proposing to continue to evaluate and monitor the feasibility of new economic energy resources.

After evaluating the proposals submitted in the RFI, it is clear the transmission network upgrade costs currently being assigned to new generation are cost prohibitive. And, SPS has several gas steam generators retiring during the Action Plan. Thus, SPS is currently evaluating the use of generator replacement or surplus interconnection rules as a way of avoiding high transmission network upgrade costs.

Finally, during the Action Plan, SPS intends to cease coal operations at Harrington and convert the units to operate on natural gas at the end of 2024.

9.02 - Status Report

SPS's 2018 IRP was indicative that SPS had adequate generating capacity over the Action Plan period 2019-2022, and, therefore SPS did not need to procure additional resources to reliably serve its customers or meet regulatory requirements. However, in keeping with SPS's 2018 IRP Action Plan, SPS received approval from the Commission of the 522 MW Sagamore Wind Facility, the 478 MW Hale Wind Facility, and the 230 MW Bonita Wind PPA Facilities which were all in-serviced within the 2019 IRP's Action Plan and were acquired because they provided low-cost renewable energy benefits to customers.

Historically low natural gas prices delayed the retirement of Plant X Unit 1, Plant X Unit 2 and Cunningham Unit 1. Each of these units is now scheduled to retire the end of 2022.

Southwestern Public Service Company 2020 Purchased Power Costs (Dollars)

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Grand Total
Capacity Costs													
Borger (Blackhawk)	981,187	981,187	981,187	981,187	981,187	993,355	1,000,399	977,878	943,437	977,020	977,020	977,020	11,752,067
Lea Power Partners (Hobbs)	3,807,427	3,809,398	3,722,083	3,724,392	3,699,694	3,978,275	4,189,441	4,208,762	4,254,790	4,258,902	4,265,141	4,277,583	48,195,887
Tokai Carbon CB (Sid Rich)	4,408	12,819	12,550	5,277	4,772	8,247	10,908	11,587	5,413	4,070	2,557	9,031	91,640
Total Capacity Costs	**4,793,023**	**4,803,404**	**4,715,820**	**4,710,856**	**4,685,653**	**4,979,877**	**5,200,748**	**5,198,227**	**5,203,640**	**5,239,992**	**5,244,718**	**5,263,635**	**60,039,594**
	Jan-20	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Grand Total**
Non-Renewable Energy Costs													
Short Term Economy Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Blackhawk	1,798,706	1,534,539	1,562,053	806,563	1,684,991	1,527,472	1,520,705	1,726,964	2,117,458	1,993,199	2,619,748	2,674,941	21,567,339
Orion Engineered Carbons	135,424	120,844	123,136	19,567	40,295	19,394	-	71,800	53,131	65,017	68,232	71,595	788,434
Tokai Carbon CB (Sid Rich)	7,631	8,497	(29)	3,212	8,795	17,132	23,013	7,893	12,284	5,111	8,597	33,788	135,925
Long Term Purchases													
Lea Power Partners - LT Tolling	2,808,737	1,480,934	1,322,672	1,631,836	4,089,598	4,008,574	4,551,181	4,628,217	4,673,405	3,550,441	3,293,571	5,590,231	41,629,397
Lea Power Partners - VO&M	829,716	544,434	610,735	777,627	818,013	816,715	981,944	991,179	927,763	895,538	667,985	767,203	9,628,851
Renewable Energy Costs													
Caprock Wind	921,524	810,531	1,023,476	870,914	575,258	919,456	634,357	488,892	635,604	840,034	956,690	774,697	9,451,433
Chaves Solar	431,786	443,956	523,663	699,508	807,473	799,155	737,527	688,904	620,628	591,748	488,430	441,722	7,274,499
Lorenzo Wind	614,284	600,101	586,456	622,177	597,174	711,507	472,175	500,528	394,799	632,902	652,722	641,422	7,026,247
Mammoth Wind	1,387,502	1,369,838	1,502,192	1,699,992	1,344,358	1,926,469	1,079,566	1,156,979	1,062,685	1,465,774	1,699,563	1,513,941	17,208,857
Mesalands	747	1,234	842	2,753	5,436	-	-	-	-	-	-	-	11,012
Palo Duro Wind	1,944,340	2,098,747	2,477,049	2,443,067	2,383,685	2,737,302	1,851,644	2,217,165	2,103,793	2,451,114	2,497,910	2,016,180	27,221,995
Roosevelt Wind	2,136,720	2,069,545	2,246,166	2,130,156	2,094,359	2,516,192	1,497,976	1,670,014	1,684,387	2,095,290	1,799,367	2,100,910	24,041,080
Roswell Solar	428,844	443,153	524,561	701,196	808,892	783,352	723,341	673,203	594,219	585,592	468,280	404,469	7,139,102
San Juan Mesa Wind	1,212,108	1,201,638	1,335,378	1,155,443	1,162,790	1,529,158	817,267	918,388	998,598	1,288,951	1,408,178	1,289,677	14,317,574
Spinning Spur Wind	2,461,932	2,764,203	3,342,110	3,624,717	3,519,049	4,258,860	2,921,163	3,275,792	2,897,224	2,904,764	1,919,662	2,593,501	36,482,977
Sun Edison Solar All	174,902	175,319	201,529	325,359	352,517	333,579	297,559	265,263	242,392	238,067	189,084	170,165	2,965,734
Texico Wind	7,122	4,072	6,158	6,251	3,573	(216)	(221)	(231)	(216)	(221)	(43)	-	26,028
Wildorado Wind	1,419,005	1,926,627	2,251,187	2,246,421	2,081,368	2,875,815	1,676,769	2,179,774	1,908,752	2,064,731	2,343,769	1,847,288	24,821,506
Wildcat Ranch Wind	1,182,309	1,097,042	1,141,318	1,144,747	1,157,466	1,347,743	915,518	960,403	803,951	1,178,700	1,215,354	1,176,605	13,321,158
QF PURPA Wind All	217,580	194,744	171,251	77,737	233,760	183,743	123,912	125,939	100,273	53,606	45,421	84,793	1,612,760
Total Purchased Power Costs	**20,120,916**	**18,889,998**	**20,951,905**	**20,989,242**	**23,768,851**	**27,311,399**	**20,825,396**	**22,547,065**	**21,831,133**	**22,900,355**	**22,342,517**	**24,193,130**	**266,671,909**

2020
INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

SPP Engineering
Version 1.0
Published 10/27/2020

SPP Southwest Power Pool

REVISION HISTORY

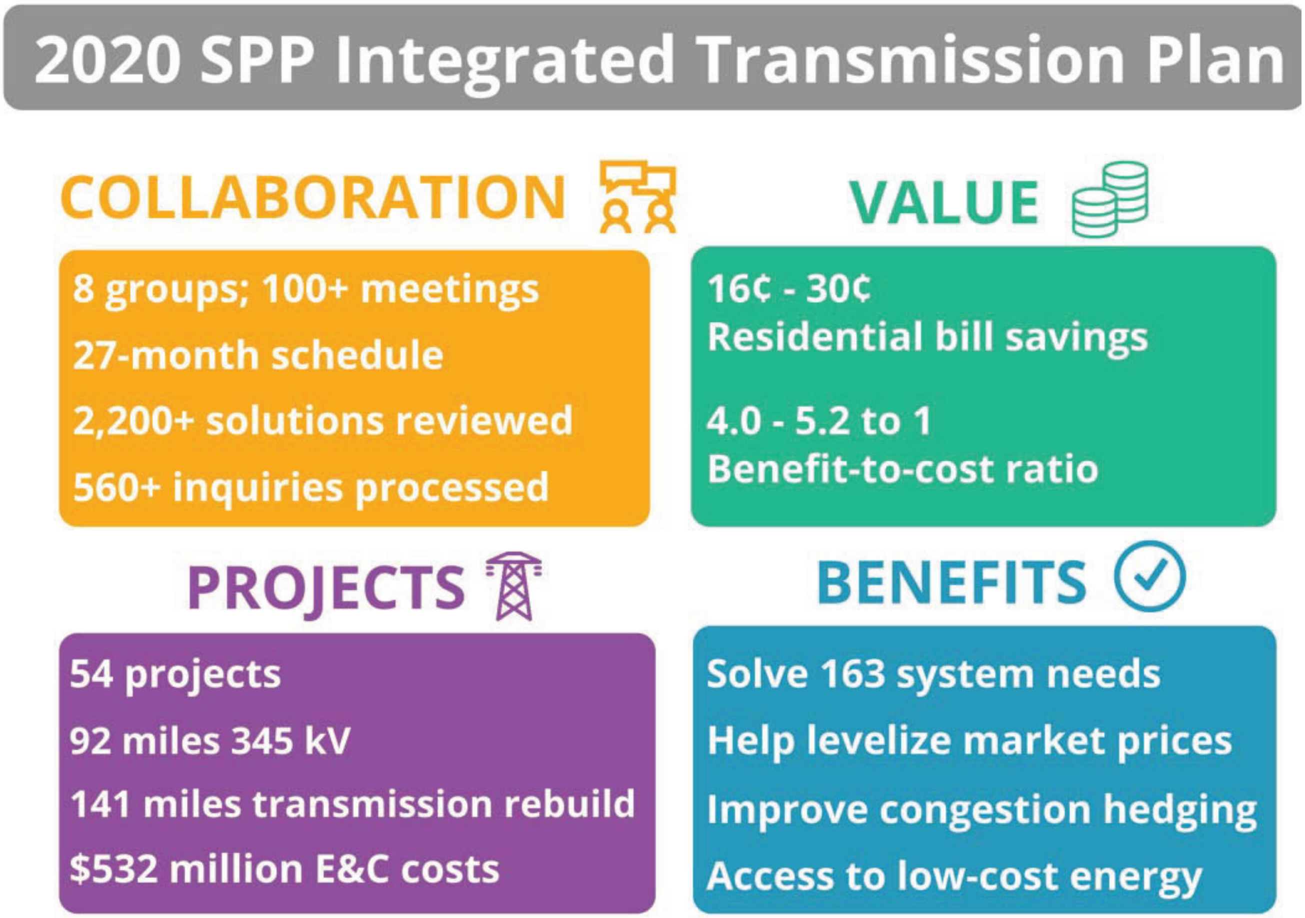
DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
9/11/2020 v0.1	SPP Staff	Initial Draft Report-Partial	Posted for stakeholder review
9/29/2020 v0.2	SPP Staff	Final Draft Report	Posted for ESWG/TWG approval
10/6/2020 v0.3	SPP Staff	Final Draft Report	Updated with stakeholder feedback and approved by ESWG/TWG
10/6/2020 v0.4	SPP Staff	Final Draft Report	Posted for MOPC
10/6/2020 v0.4	SPP Staff	Final Draft Report - Updated	Updated with stakeholder feedback given during the October 6, 2020 ESWG/TWG working group; posted for MOPC
10/13/2020 v0.4	SPP Staff	Final Draft Report	Approved by MOPC
10/15/2020 v0.5	SPP Staff	Final Draft Report – Updated	Redlined version: Updated table 6.15 to correct 40-year and net benefit calculations; tables 8.10-8.13 to correct some benefit numbers; changed NTC to NTC-C where appropriate based on MOPC participant feedback; and added footnotes to tables 8.12, 8.13, 8.16 and 8.17 to clarify state level numbers; adding "- APC benefit only" to figures 0.2 and 6.10 and table 6.15.
10/19/2020 v0.5	SPP Staff	Final Draft Report	Posted for SPP Board of Directors
10/27/2020 v1.0	SPP Staff	Final Report	Approved by SPP Board of Directors

CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY



2020 SPP Integrated Transmission Plan

COLLABORATION

8 groups; 100+ meetings
27-month schedule
2,200+ solutions reviewed
560+ inquiries processed

VALUE

16¢ - 30¢
Residential bill savings

4.0 - 5.2 to 1
Benefit-to-cost ratio

PROJECTS

54 projects
92 miles 345 kV
141 miles transmission rebuild
$532 million E&C costs

BENEFITS

Solve 163 system needs
Help levelize market prices
Improve congestion hedging
Access to low-cost energy

The 2020 Integrated Transmission Plan (ITP) looks ahead 10 years to ensure the SPP region can deliver energy reliably and economically, facilitate public policy objectives, seek solutions with neighboring regions and maximize benefits to end-use customers. Over 27 months, SPP and its member organizations worked together to forecast and analyze the regional transmission system's economic, reliability, operational and public policy needs.

SPP evaluated more than 2,200 solutions. The analysis resulted in the recommendation to approve 54 transmission projects, including 91.8 miles of new extra-high-voltage (EHV) transmission and 140.9[1] miles of rebuilt high-voltage infrastructure.

---

[1] This mileage number assumes the partial rebuild and new mileage of the Butler-Tioga 138 kV new line. This line is expected to follow the existing Butler-Altoona 138 kV right-of-way and break away towards Tioga at a point that that would minimize transmission costs for the project.

This portfolio contains reliability and economic projects that will mitigate 163 system issues. Reliability projects allow the region to meet compliance requirements and keep the lights on through loading relief, voltage support and system protection.

There are several primary drivers of the economic projects. Many of the projects enable delivery of low-cost renewable resources and reduce price separation in the SPP marketplace caused by congestion. Continued rapid renewable expansion has caused increasing pricing disparity between the western and eastern portions of the SPP system. These disparities have created higher average costs for eastern load centers because of congestion and lack of access to less expensive generation. Price differences have only been marginally delayed by new interconnections seeking opportunity in the east. The recommended economic projects will reduce separation between generator and load locational marginal prices across the region and create reliable transfer capability that will allow the system to realize benefits from low-cost generation.

Previous ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts. Overly conservative forecasts can lead to delayed transmission investment, contributing to persistent congestion. For example, the 2020 consolidated portfolio is expected to address eight congested flowgates identified over the last four quarterly SPP corporate metric updates. For the 2020 ITP assessment, SPP expanded on the 2019 assessment’s analysis to better forecast renewables development, which will allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to less expensive energy.

The SPP region has areas of increased load growth due to oil and gas exploration in North Dakota and New Mexico. Some of these areas could experience voltage collapse. Additional transmission capacity is needed to serve this new load. SPP developed projects to address this load growth; some are recommended for construction while others need continued analysis.

Three distinct scenarios were considered to account for variations in system conditions over 10 years. These scenarios consider requirements to support firm deliverability of capacity for reliability (base reliability) while exploring rapidly evolving technology that may influence the transmission system and energy industry (Future 1/Future 2). The scenarios included varied wind projections, utility-scale and distributed solar, energy storage resources, generation retirements and electric vehicles.

The final project portfolio was tested against a wide range of sensitivities, including natural gas prices, generator retirements, renewables development, battery storage and demand. The analysis determined that adjusted production cost savings across all sensitivities had a benefit-to-cost ratio greater than 1.0. When considering all eight benefit metrics, including adjusted production cost savings, the consolidated portfolio is expected to provide a 40-year benefit-to-cost ratio ranging from 4.0 for Future 1 to 5.2 for Future 2. The net impact to ratepayers is a savings of $0.16 to $0.30 on the average retail residential monthly bill. See Section 8.3 Sensitivity Analysis for more information.

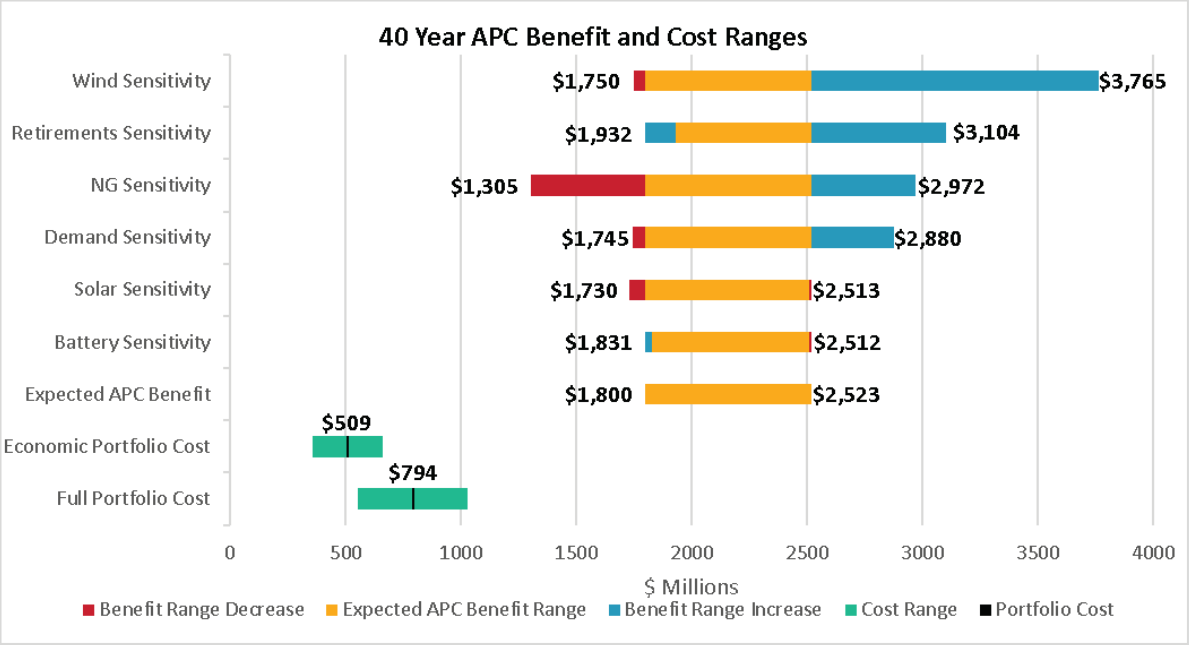


Figure 0.1: 40-Year APC Benefit and Cost Ranges

SPP assumes a 40-year lifespan for new transmission investments. Within 20 years, the SPP region is expected to receive more benefits from the projects than their total investment costs. The projects will begin providing net savings to ratepayers within the first year of being in-service.

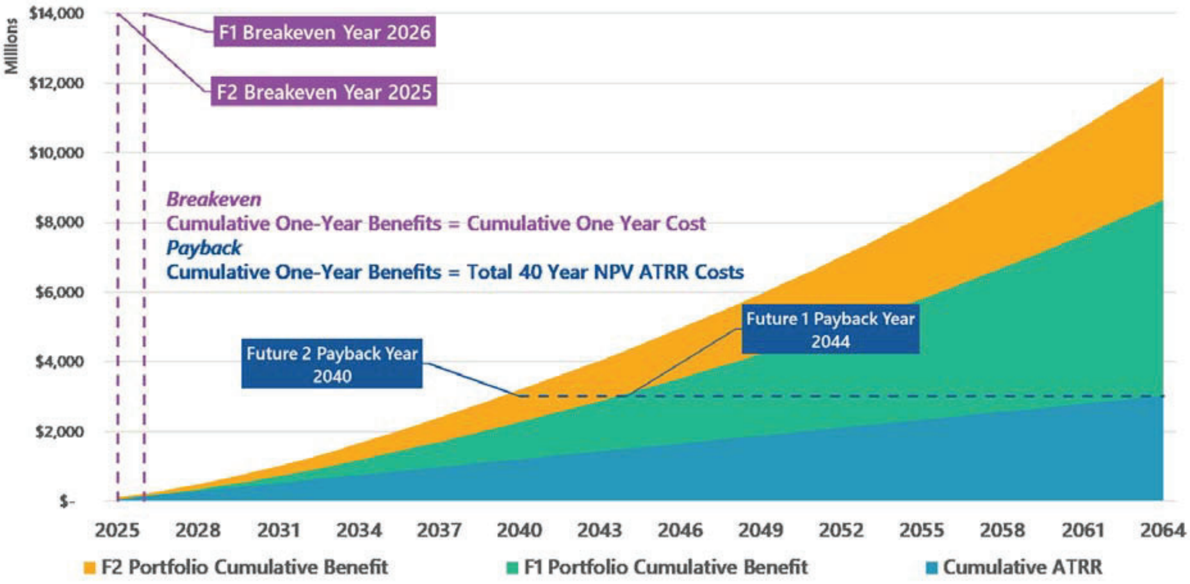


Figure 0.2: Portfolio Breakeven and Payback – APC benefit only

The 2020 ITP Assessment includes the following projects:

Project	Area	Type	Project Cost (2020$)	Miles	NTC/ NTC-C
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	BEPC	R	$3,562,780	-	NTC
Anadarko-Gracemont 138 kV rebuild as double-circuit	WFEC/ OKGE	E	$8,297,502	14.4	NTC Modification
Russett-South Brown 138 kV rebuild	WFEC/ SWPA	E	$10,067,432	18.62	NTC
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	WERE	E	$135,720,424	91.2	NTC-C
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	GRDA	E	$1,410,000	-	NTC
Columbus East 230/115 kV transformer replacement	NPPD	E	$4,600,000	-	No
Franks-South Crocker-Lebanon 161 kV terminal equipment	AECI	E	$5,721,430	-	No
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	AEPW/ OKGE	E	$31,686,685	0.84	NTC-C
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	WFEC	E	$1,617,500	-	NTC
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	OKGE/ WFEC	E	$113,620,907	48	NTC-C
Split Rock 345/115 kV Circuit 10 and 11 terminal equipment	NSPP	E	$4,577,336	-	No
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	EREC/ WAPA /BEPC	E	$1,528,722[2]	-	No
Circleville-Goff 115 kV circuit 1 rebuild	WERE	R	$12,114,772	14.56	NTC
Goff-Kelly 115 kV rebuild	WERE	R	$7,108,395	10.11	NTC
South Shreveport-Wallace Lake 138 kV rebuild	AEPW	R	$23,622,577	11.18	NTC-C
Grady 138 kV capacitor bank	AEPW	R	$688,781	-	NTC
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	EREC/ NWE	R	$11,394,000	14.4	NTC
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	OKGE	R	$5,362,799	5.9	NTC
Bushland-Deaf Smith 230 kV terminal equipment	SPS	R	$923,938	-	NTC
Newhart-Potter County 230 kV terminal equipment	SPS	R	$731,282	-	NTC
Carlisle-Murphy 115 kV rebuild	SPS	R	$4,746,175	4.0	NTC

---

[2] The cost estimate was adjusted late in the study process to be $3,748,722 due to a gap in the Study Estimate requests sent to stakeholders. This updated cost estimate is only considered in Table 9.1 and the NTC recommendations of this executive summary. See additional information in section 7.3.11.

Project	Area	Type	Project Cost (2020$)	Miles	NTC/ NTC-C
Roswell 115/69 kV replace transformer #1	SPS	R	$2,777,743	-	NTC
S3456-S3458 345 kV terminal equipment	OPPD	R	$678,865	-	No
Meadowlark-Tower 33 115 kV rebuild	WERE	R	$1,342,588	0.93	NTC
Jones-Lubbock South 230 kV terminal equipment circuit 1	SPS	R	$666,728	-	No
Jones-Lubbock South 230 kV terminal equipment circuit 2	SPS	R	$397,668	-	No
Deaf Smith-Plant X 230 kV terminal equipment	SPS	R	$2,100,196	-	NTC
Newhart-Plant X 230 kV terminal equipment	SPS	R	$2,024,293	-	NTC
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	SPS	R	$872,391	-	NTC
Allen-Lubbock South 115 kV rebuild	SPS	R	$6,817,226	6.0	NTC
Allen-Quaker 115 kV rebuild	SPS	R	$4,732,267	3.6	NTC
Russell 115 kV capacitor bank	SEPC	R	$2,841,951	-	NTC
Eddy County-North Loving 345 kV new line	SPS	R	$64,422,600	42.96	No
Maljamar 115 kV capacitor bank	SPS	R	$685,440	-	No
Devil's Lake 115 kV reactor	WAPA	R	$1,190,000	-	NTC
Bismarck 115 kV reactors	WAPA	R	$2,380,700	-	NTC
Moorehead 230 kV reactor	MRES	R	$1,515,440	-	NTC
Agate 115 kV reactor	WAPA	R	$571,200	-	NTC
Replace four breakers at Anadarko 138 kV	WFEC	R	$850,000	-	NTC
Replace three breakers at Northeast 161 kV	KCPL	R	$887,479	-	NTC
Replace one breaker at Stilwell 161 kV	KCPL	R	$566,485	-	NTC
Replace one breaker at Leeds 161 kV	KCPL	R	$566,485	-	NTC
Replace one breaker at Shawnee Mission 161 kV	KCPL	R	$566,485	-	NTC
Replace one breaker at Southtown 161 kV	KCPL	R	$566,485	-	NTC
Replace two breakers at Lake Road 161 kV	KCPL	R	$1,132,970	-	NTC
Replace two breakers at Craig 161 kV	KCPL	R	$1,132,970	-	NTC
Nixa-Nixa Espy 69 kV terminal equipment	GLHP	R	$91,147	-	No
Deaf Smith #6-Hereford 115 kV rebuild	SPS	R	$6,660,556	2.33	NTC
Deaf Smith #6-Friona 115 kV rebuild	SPS	R	$12,626,190	18.9	NTC
Cargill-Friona 115 kV rebuild	SPS	R	$817,466	1.15	NTC
Cargill-Deaf Smith #24 115 kV rebuild	SPS	R	$5,501,901	7.74	NTC
Deaf Smith #24-Parmer 115 kV rebuild	SPS	R	$824,574	1.16	NTC
Deaf Smith #20-Parmer 115 kV rebuild	SPS	R	$5,402,384	7.6	NTC
Curry-Deaf Smith #20 115 kV rebuild	SPS	R	$9,048,993	12.73	No
		Total	**$532,363,304**[3]		

Table 0.1: 2020 ITP Consolidated Portfolio

---

[3] These costs represent engineering and construction cost provided during the study by SPP stakeholders or its third-party cost estimator.

This map depicts the 2020 ITP Assessment thermal/voltage reliability projects:

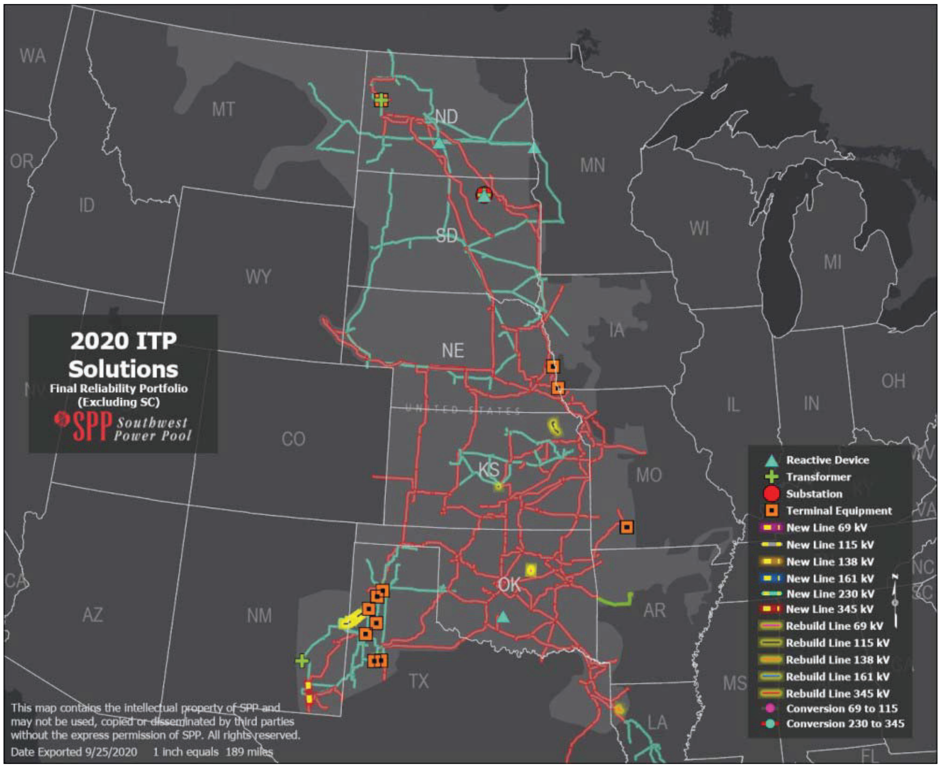


Figure 0.3: 2020 ITP Thermal and Voltage Reliability Projects

This map depicts the 2020 ITP Assessment short circuit reliability projects:

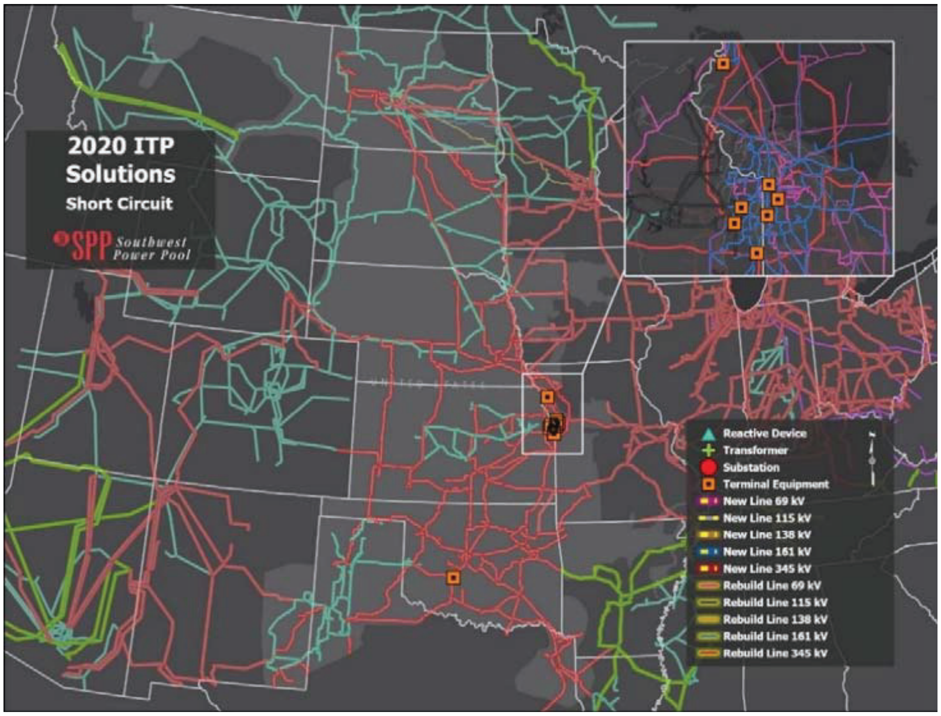


Figure 0.4: 2020 ITP Short Circuit Reliability Projects

This map depicts the 2020 ITP Assessment economic projects:

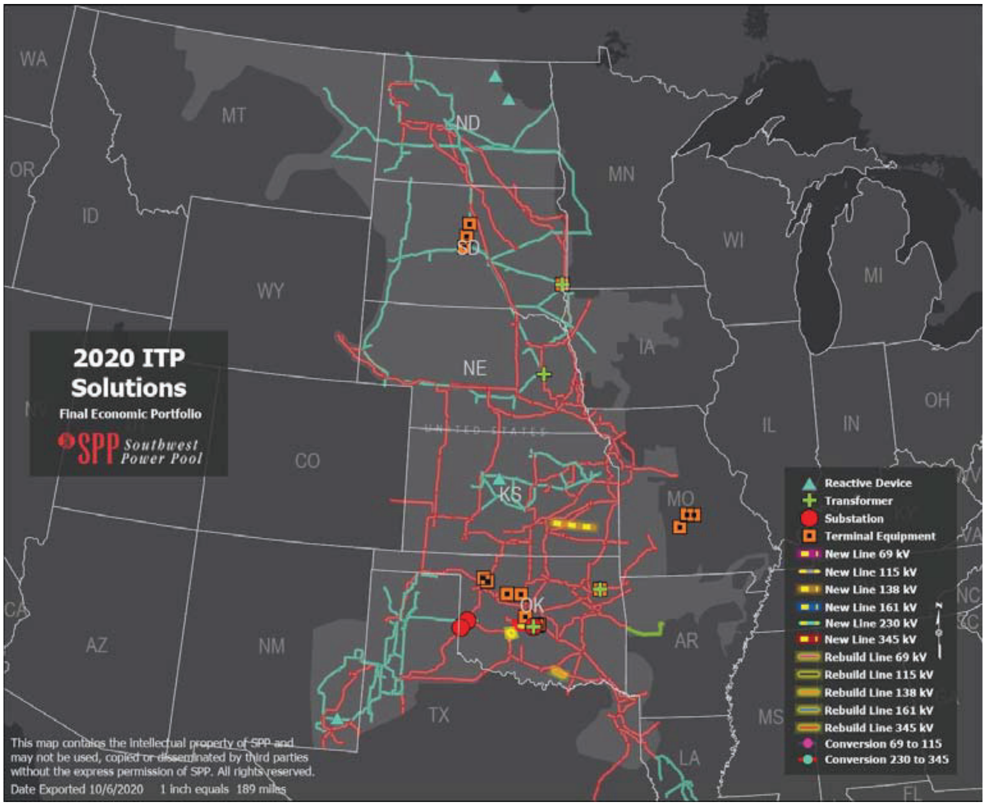


Figure 0.5: 2020 ITP Portfolio-Economic

SPP staff makes Notification to Construct (NTC) recommendations for projects included in the consolidated portfolio based on results from the staging process and SPP Business Practice 7060. If financial expenditure is required within four years from board approval, the project is recommended for an NTC or NTC-C (Notification to Construct with Conditions).

1 INTRODUCTION

1.1 THE ITP ASSESSMENT

The SPP Integrated Transmission Planning (ITP) process promotes transmission investment to meet near- and long-term reliability, economic, public policy and operational transmission needs. The ITP process coordinates solutions with ongoing compliance, local planning, interregional planning and tariff service processes. The goal is to develop a 10-year regional transmission plan that provides reliable and economic energy delivery and achieves public policy objectives, while maximizing benefits to the end-use customers.

The 2020 ITP assessment is guided by requirements defined in Attachment O to the SPP Open Access Transmission Tariff (Tariff), the ITP Manual, and the 2020 ITP Scope. Previous improvements to the ITP process were designed by the Transmission Planning Improvement Task Force and implemented beginning in the 2019 ITP.

The ITP process is open and transparent, allowing for stakeholder input throughout the assessment. Study results are coordinated with other entities, including those embedded within the SPP footprint and neighboring first-tier entities.

The objectives of the ITP are to:

- Resolve reliability criteria violations.
- Improve access to markets.
- Improve interconnections with SPP neighbors.
- Meet expected load-growth demands.
- Facilitate or respond to expected facility retirements.
- Synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Attachment AQ processes.
- Address persistent operational issues as defined in the scope.
- Facilitate continuity in the overall transmission expansion plan.
- Facilitate a cost-effective, responsive, and flexible transmission network.

1.2 REPORT STRUCTURE

This report describes the ITP assessment of the SPP transmission system for a 10-year horizon, focusing on years 2022, 2025 and 2030. These years were evaluated with a baseline reliability scenario and two future market scenarios (futures). The Model Development and Benchmarking sections summarize modeling inputs and address the concepts behind this study's approach, key procedural steps in analysis development, and overarching study assumptions. The Needs Assessment through Project

Recommendations sections address specific results, describe projects that merit consideration, and contain portfolio recommendations, benefits and costs.

Within this study, any reference to the SPP footprint refers to the Balancing Authority Area, as defined in the Tariff, whose transmission facilities are under the functional control of the SPP regional transmission organization (RTO), unless otherwise noted.

The study was guided by the 2020 ITP Scope and SPP ITP Manual.[4] All reports and documents referenced in this report are available on the SPP website.[5]

SPP staff and its stakeholders frequently exchange proprietary information in the course of any study, and such information is used extensively for ITP assessments. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data considered not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities, and plans for new facilities that are considered non-sensitive data.

1.3 STAKEHOLDER COLLABORATION

Stakeholders developed the 2020 ITP assessment assumptions and procedures in meetings throughout 2018, 2019, and 2020. Members, liaison members, industry specialists and consultants discussed the assumptions and facilitated a thorough evaluation.

The following SPP organizational groups were involved:

- Transmission Working Group (TWG)
- Economic Studies Working Group (ESWG)
- Model Development Working Group (MDWG)
- Cost Allocation Working Group (CAWG)
- Project Cost Working Group (PCWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- Regional State Committee (RSC)
- Board of Directors (Board)

SPP staff served as facilitators for these groups and worked closely with each working group's chairperson to ensure all views were heard and considered consistent with the SPP value proposition.

These working groups tendered policy-level considerations to the appropriate organizational groups, including the MOPC and SPC. Stakeholder feedback was instrumental in the refinement of the 2020 ITP.

---

[4] https://www.spp.org/Documents/60911/itp%20manual%20version%202.7.docx; the ITP assessment follows the current ITP Manual and versions may differ throughout the study process. The version that was current at the time of the study was used.

[5] https://spp.org/

1.3.1 PLANNING SUMMITS

In addition to the standard working group meetings and in accordance with Attachment O of the Tariff, SPP held multiple transmission planning summits to elicit further input and provide stakeholders with additional opportunities to participate in the process of discussing and addressing planning topics.[6]

---

[6] 2020 Engineering Planning Summit was held on Wednesday, July 8, 2020 (https://www.spp.org/Documents/62539/Engineering%20Planning%20Summit%20Agenda%20&%20Background%20Materials%2020200708.zip)

2 MODEL DEVELOPMENT

2.1 BASE RELIABILITY MODELS

2.1.1 GENERATION AND LOAD

Generation and load data in the 2020 ITP base reliability models was incorporated based on specifications documented in the ITP Manual. For items not specified in the ITP Manual, SPP followed the SPP Model Development Working Group (MDWG) Procedure Manual.[7] Renewable dispatch amounts are based on historical averages for resources with long-term firm transmission service for the summer and winter seasons. For the light load models, all wind resources with long-term firm transmission service were dispatched to the lesser of the full long-term firm transmission service amount or nameplate amount, with remaining generation coming from conventional resources. In these base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.

The Powerflow Model benchmarking section details the generation dispatch and load in the base reliability models.

2.1.2 TOPOLOGY

Topology data in the 2020 ITP base reliability models was incorporated in accordance with the ITP Manual. For items not specified in the ITP Manual, SPP followed the MDWG Model Development Procedure Manual. The topology for areas external to SPP was consistent with the 2018 Eastern Interconnection Reliability Assessment Group Multi-regional Modeling Working Group (MMWG) model series.

2.1.3 SHORT-CIRCUIT MODEL

A short-circuit model representative of the year-two, summer peak, was developed for short-circuit analysis. This short-circuit model has all modeled generation and transmission equipment in service to simulate the maximum available fault current, excluding exceptions such as normally open lines or retired generation. This model was analyzed in consideration of the North American Electric Reliability Corporation (NERC) TPL-001 standard.

2.2 MARKET ECONOMIC MODEL

2.2.1 MODEL ASSUMPTIONS AND DATA

2.2.1.1 Futures Development

Stakeholders determined that the best option was to carry forward the 2019 ITP reference case and emerging technologies framework, while allowing adjustments to specific drivers. SPP staff provided stakeholders with a survey to identify the policy drivers which required adjustments for the 2020 ITP. The drivers considered for adjustment were:

---

[7] Model Development Working Group (MDWG) Procedure Manual; the MDWG Procedure Manual may differ throughout the study process. The version that was current at the time of the study was used.

- Wind and solar capacity additions
- Energy growth rates
- Natural gas prices
- Age-based retirement assumptions
- Energy storage[8]
- Carbon adder

2.2.1.1.1 Future 1: Reference Case

The reference case future will reflect the continuation of current industry trends and environmental regulations. For years five and 10, coal generators over the age of 56 will be retired, while gas fired and oil generators over the age of 50 years will be retired subject to review from generator owners. Exceptions will be allowed based on stakeholder review. Long-term industry forecasts will be used for natural gas and coal prices. Solar and wind additions will exceed current renewable portfolio standards due to economics, public appeal, and the anticipation of potential policy changes, as reflected in historical renewable installations. Battery energy storage resources will also be included relative to the approved solar amounts.

2.2.1.1.2 Future 2: Emerging Technologies

The emerging technologies future will be driven primarily by the assumption that electrical vehicles, distributed generation, demand response, and energy efficiency will impact energy growth rates. Coal generators over the age of 56 will be retired, while gas-fired and oil generators over the age of 50 will be retired. Exceptions will be allowed for repowering (life extension) or emissions upgrades if approved by the ESWG. As in the reference case future, current environmental regulations will be assumed and natural gas and coal prices will use long-term industry forecasts. This future assumes higher solar, wind, and energy storage resource additions than the reference case due to advances in technology that decrease capital costs and increase energy conversion efficiency.

Table 2.1 summarizes the drivers and how they were considered in each future.

	Drivers		
Key Assumptions	**Year 2**	**Reference Case** **Year 5 Year 10**	**Emerging Technologies** **Year 5 Year 10**
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast	Increase due to electric vehicle growth
Natural Gas Prices	Current industry forecast	Current industry forecast	Current industry forecast
Coal Prices	Current industry forecast	Current industry forecast	Current industry forecast

---

[8] Energy storage is specific to batteries.

	Drivers				
Key Assumptions	Year 2	Reference Case		Emerging Technologies	
		Year 5	Year 10	Year 5	Year 10
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner review		Coal age-based 56+, Gas/Oil age-based 50+, subject to repowering or emissions upgrades	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[9]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		+300MW	+500MW
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	None	20% of projected solar		35% of projected solar	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	4	7	5	9
Wind (GW)	Existing + RARs	26	28	30	33

Table 2.1 Future Drivers

2.2.1.2 Load and Energy Forecasts

The 2020 ITP load review focused on load data through 2030. The load data was derived from the base reliability model set, and stakeholders were asked to identify/update the following parameters:

- Assignment of loads to companies
- Forecasted system peak load (MW)
- Loss factors
- Load factors
- Load demand group assignments
- Monthly peak and energy allocations
- Station service loads
- Resource planning peak loads and load factors

The ESWG- and TWG-approved load review was used to update the load information in the market economic models. Figure 2.1 shows the total coincident peak load for all study years. Figure 2.2 shows the monthly energy per future for all study years (2022, 2025, and 2030).

---

[9] As defined in the MDWG Model Development Procedure Manual: Model Development Working Group (MDWG) Procedure Manual

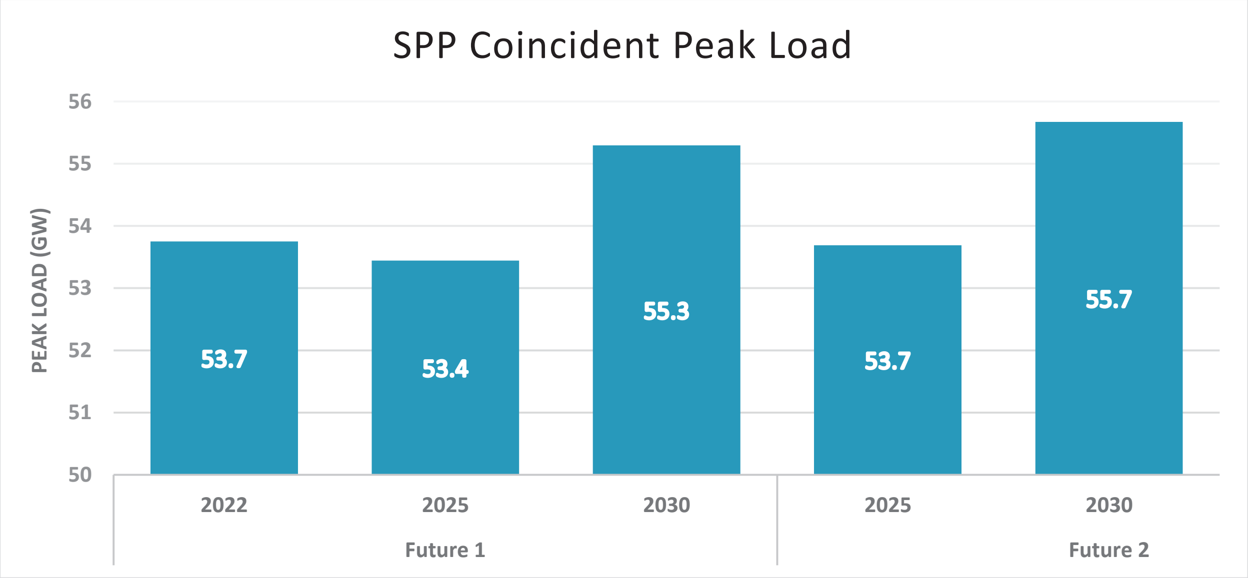


Figure 2.1: Coincident Peak Load

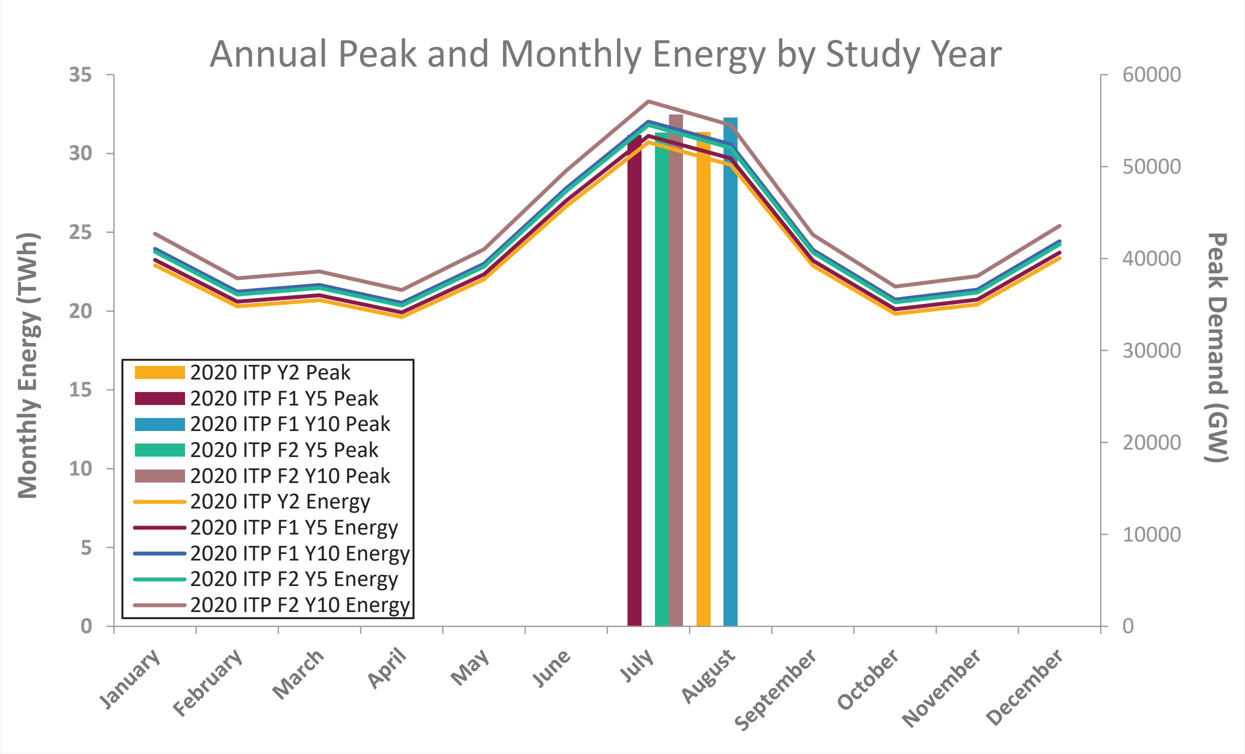


Figure 2.2: 2020 ITP Annual Energy

2.2.1.3 Renewable Policy Review

Renewable policy requirements enacted by state laws, public power initiatives and courts are the only public policy initiatives considered in this ITP via the renewable policy review. These requirements are defined as percentages and outlined in the ITP manual. The 2020 ITP renewable policy review focused on renewable requirements through 2030.

2.2.1.4 Generation Resources

Existing generation data originated from the ABB Simulation Ready Data Fall 2017 Reference Case and was supplemented with SPP stakeholder information provided through the SPP Model on Demand tool and the generation review.

Figure 2.3 and Figure 2.4 detail the annual nameplate capacity and energy by unit/fuel type, respectively for 2022, 2025 and 2030 for Future 1, and 2025 and 2030 for Future 2.

In addition to resources accepted in the base reliability models, stakeholders were given the chance to request additional generation resources in the ITP models through the Resource Addition Request (RAR) process. As a result of the RAR process, 1.5 GW of wind generation was added to the market economic models, all of which was included in the year-two model.

Generator operating characteristics, such as operating and maintenance (O&M) costs, heat rates, and energy limits were also provided for stakeholders to review.

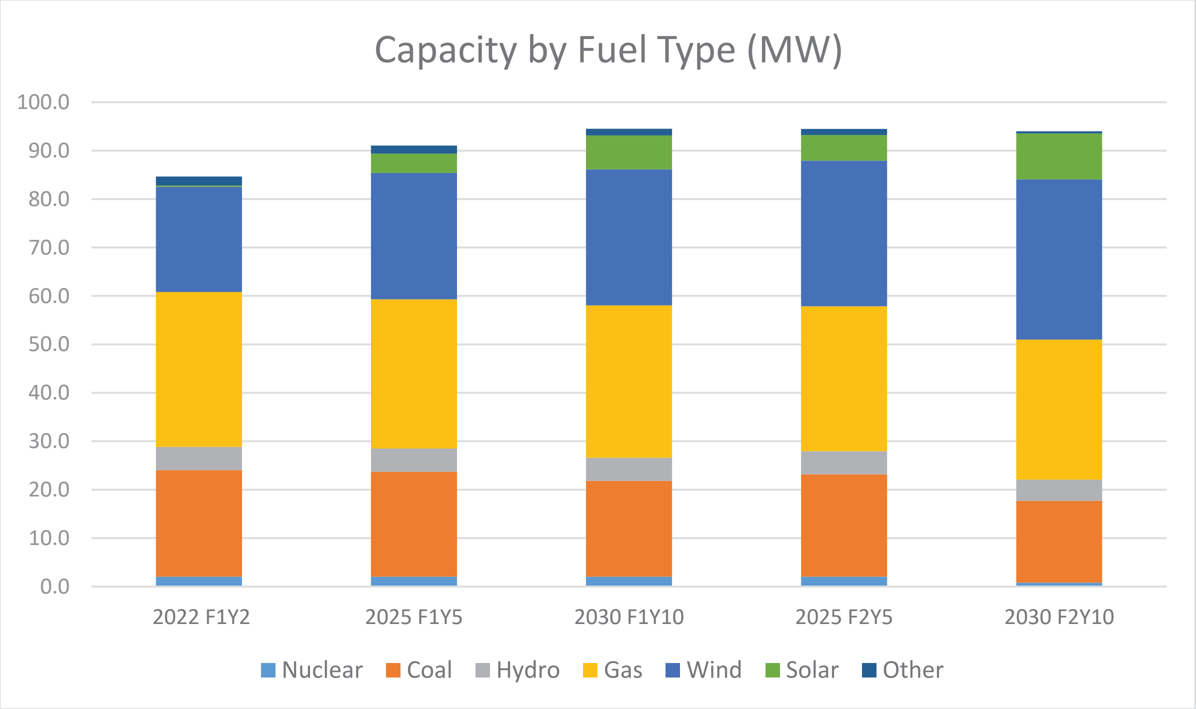


Figure 2.3: Capacity by Fuel Type (MW)

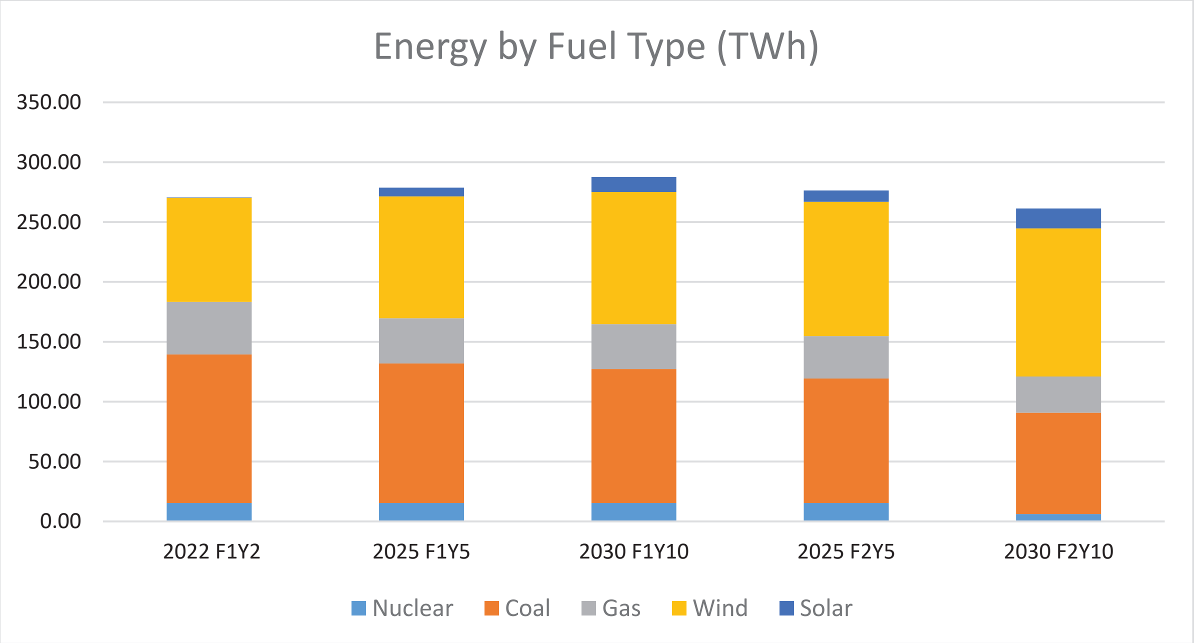


Figure 2.4: Energy by Fuel Type (TWh)

Figure 2.5 identifies the amount of retired conventional generation compared to retirements identified in the base reliability models. The figure reflects the final set of retirements based on the approved futures assumptions.

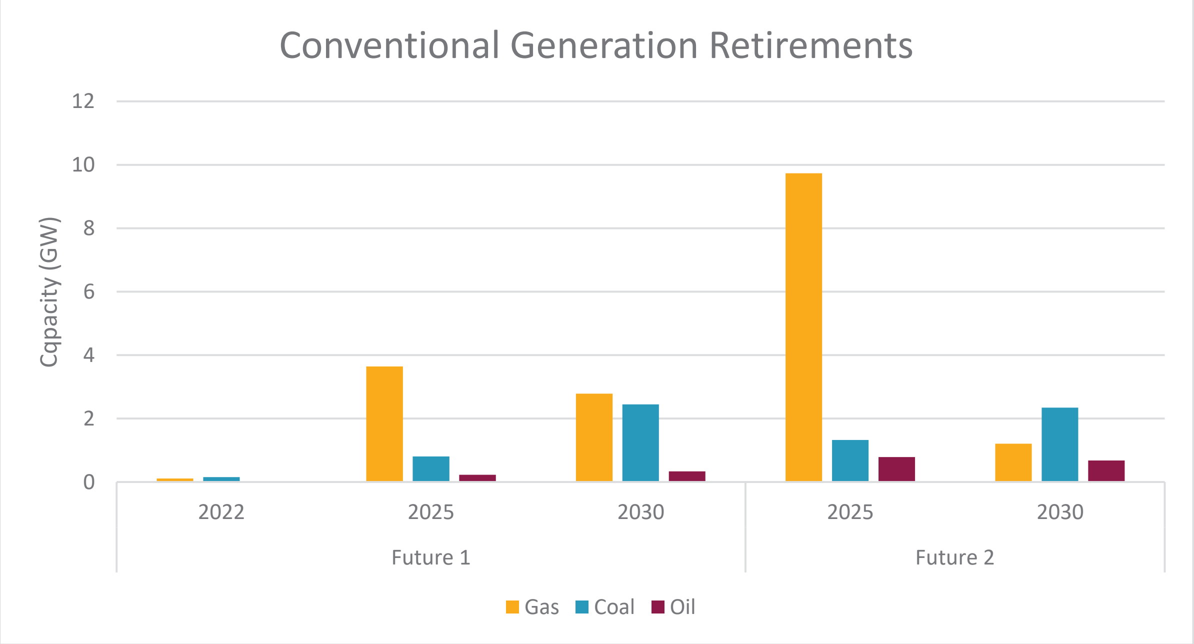


Figure 2.5: Conventional Generation Retirements

2.2.1.5 Fuel Prices

The ABB Simulation Ready Data Fall 2017 Reference Case and ABB fundamental forecast (for long-term natural gas price projections) were utilized for the fuel price forecasts. Figure 2.6 shows the annual average natural gas and coal prices for the study horizon. Between 2021 and 2030, these prices increase from $3.17 to $5.21 (~5.1 percent compound average escalation) and $2.30 to $2.87 (~2.5 compound average escalation) for natural gas and coal, respectively.

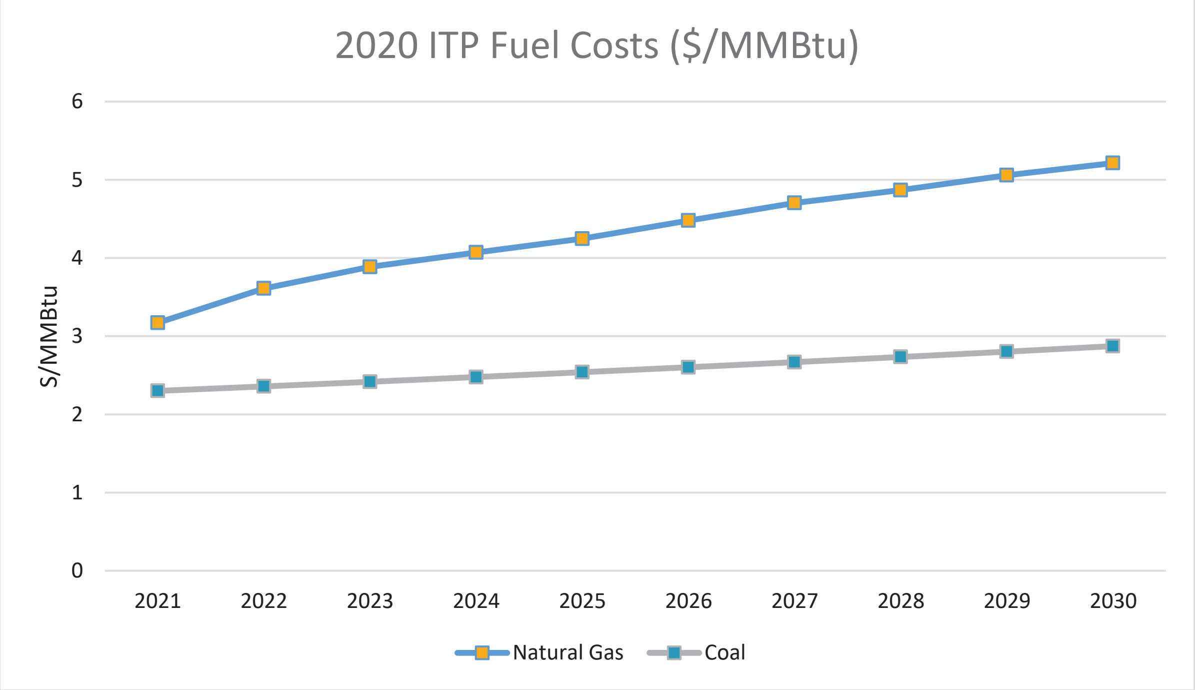


Figure 2.6: ABB Fuel Annual Average Fuel Price Forecast

2.2.2 RESOURCE PLAN

In order to evaluate transmission for a 10-year horizon, a key component begins with identifying the resource outlook for each future. The SPP generation portfolio will not be the same in 10 years, due to the changing load forecasts, resource retirements and fast-changing mix of resource additions. SPP staff developed resource expansion plans to meet renewable portfolio standards, resource reserve margin requirements, and future specific renewable and emerging technology projections.

2.2.2.1 Renewable Resource Expansion Plan

Each utility was analyzed to determine if the assumed renewable mandates and goals identified by the renewable policy review could be met with existing generation and initial resource projections for 2025 and 2030. If a utility was projected to be unable to meet requirements, additional resources were assigned to the utilities from the total projected renewable amounts to meet renewable portfolio standards. For states with a standard that could be met by either wind or solar generation, a ratio of 80 percent wind additions to 20 percent solar additions was utilized. This split was representative of the active GI queue requests for wind and solar resources.

The incremental renewables assigned to meet renewable mandates and goals in the SPP footprint by 2030 were 289.4 MW in Future 1 and 289.9 MW in Future 2.

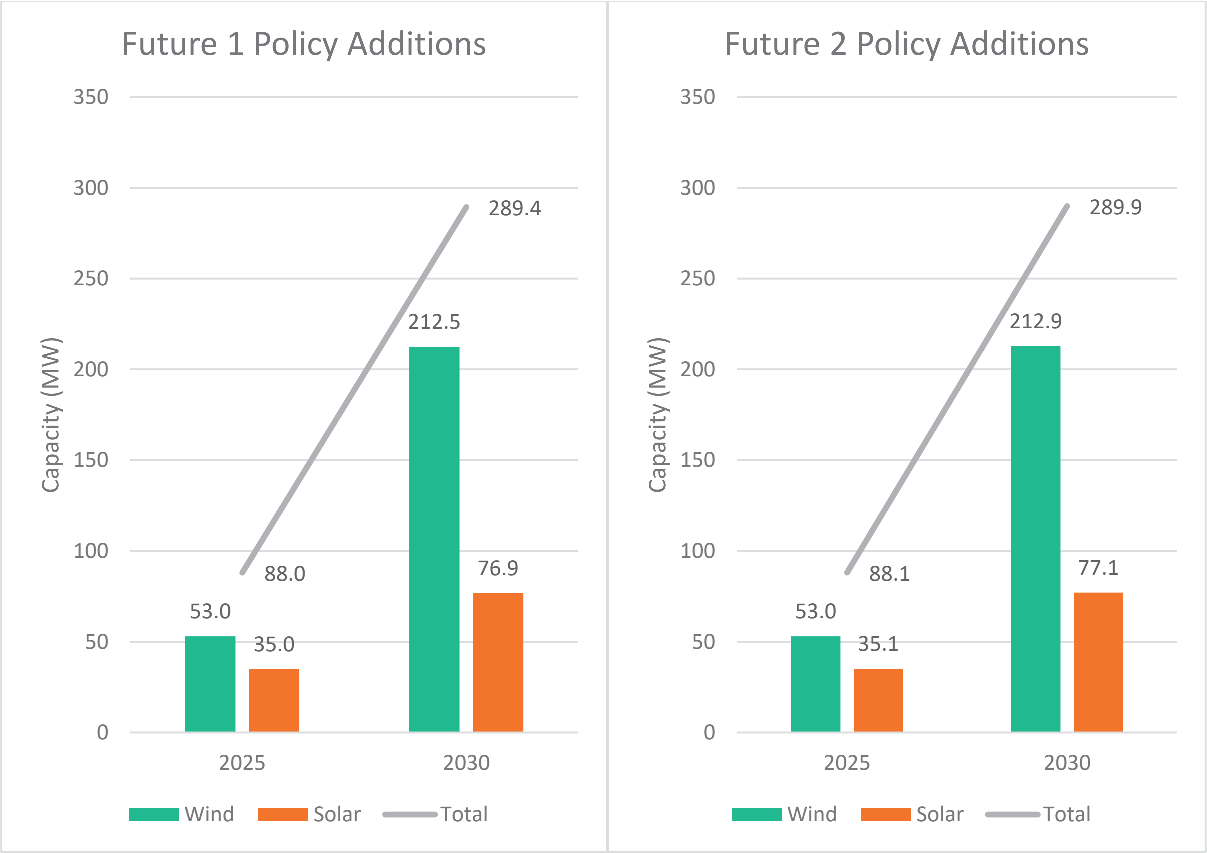


Figure 2.7: SPP Renewable Generation Assignments to meet Mandates and Goals

After ensuring renewable portfolio standards were met by assigning renewables, SPP staff accredited the remaining projected renewable capacity to each pricing zone.

Projected solar additions were assigned based on the load-ratio share for each pricing zone. Projected wind additions were accredited to deficient zones to maximize the available accreditation of renewables for each zone, up to the 12 percent zonal renewable cap defined in the study scope. Resources were accredited in the following order:

- Existing generation
- Policy wind and solar additions
- Projected solar additions
- Projected storage additions
- Projected wind additions
- Conventional additions

2.2.2.2 Conventional Resource Expansion Plan

The renewable resource expansion plan for each future was utilized as an input to the corresponding conventional resource expansion plan to ensure appropriate resource adequacy within the SPP footprint. ABB Strategist® software was used to develop the conventional resource expansion plan for each future, assessing a 20-year horizon.

Utilities that did not meet the 12 percent planning reserve margin requirement set by SPP Planning Criteria[10] also received capacity from the conventional resource plan. Projected reserve margins were calculated for each pricing zone using existing generation, projected renewable generation, fleet power purchase agreements, and load projections through 2040. Each zone that was not yet meeting its minimum reserve requirement was assigned conventional resources in 2025 and 2030 of both futures.

Nameplate conventional generation capacity assigned to pricing zones were counted toward each zone's capacity margin requirement. Existing wind and solar capacity, being intermittent resources, were included at a percentage of nameplate capacity, in accordance with the calculations in SPP Planning Criteria 7.1.5.3. SPP stakeholders were surveyed for feedback on accreditation percentages for existing renewable capacity.

In the analysis of future conventional capacity needs, available resource options were combined cycle (CC) units, fast-start combustion turbine (CT) units, and reciprocating engines. Generic resource prototypes from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2018[11] were utilized. These resource prototypes define operating parameters of specific generation technologies to determine the optimal generation mix to add to the region.

CTs were the only technology selected in Futures 1 and 2 to meet capacity requirements. ESWG approved replacing three CTs with one CC located in the Southwestern Public Service Company (SPS) area for each future.

While both futures represent normal load growth, more resource additions are needed in Future 2 due primarily to the additional unit retirements.

Table 2.2 shows the total nameplate generation additions by future and study year to meet futures definitions and resource adequacy requirements. Figure 2.8 shows the nameplate generation additions by future, study year, and capacity type for the SPP region.

	Future 1	Future 2
2025	10.5 GW	23.0 GW
2030	11.6 GW	33.1 GW

Table 2.2: Total Nameplate Generation Additions by Future and Study Year

---

[10] SPP Planning Criteria

[11] EIA Annual Energy Outlook 2018 Report

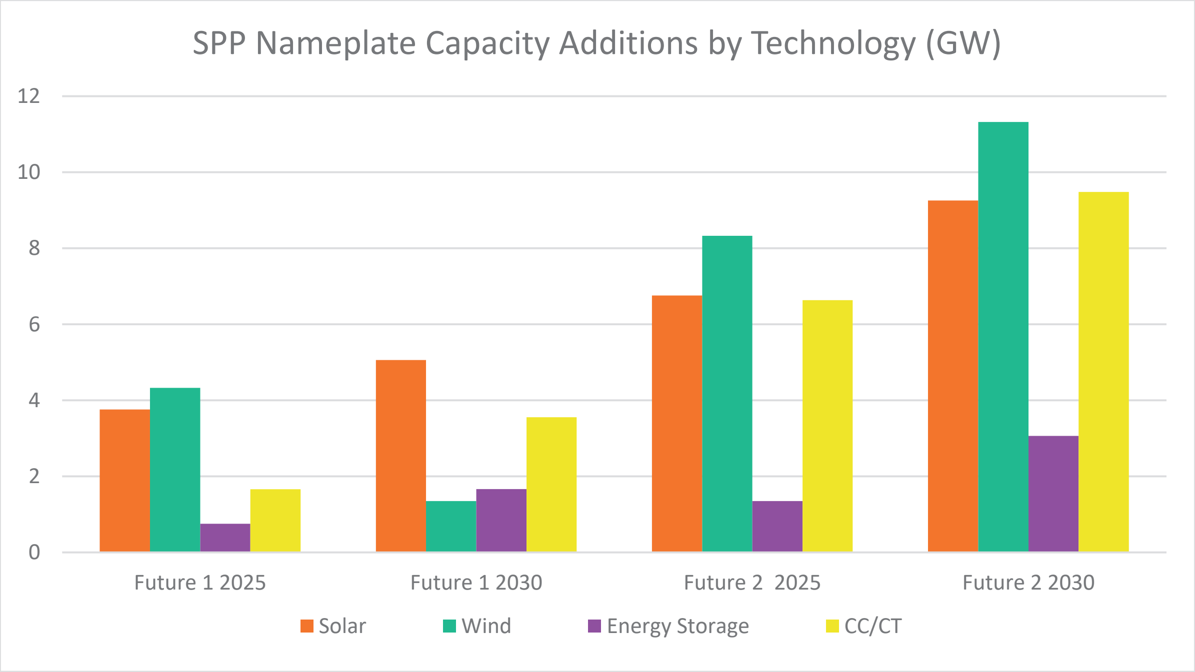


Figure 2.8: SPP Nameplate Capacity Additions by Technology (GW)

Table 2.3 shows the total accredited generation additions by future and study year. Figure 2.9 shows accredited generation additions by future, study year, and technology for the SPP region.

	Future 1	**Future 2**
2025	5.9 GW	12.7 GW
2030	10.2 GW	16.5 GW

Table 2.3: Total Accredited Generation Additions by Future and Study Year

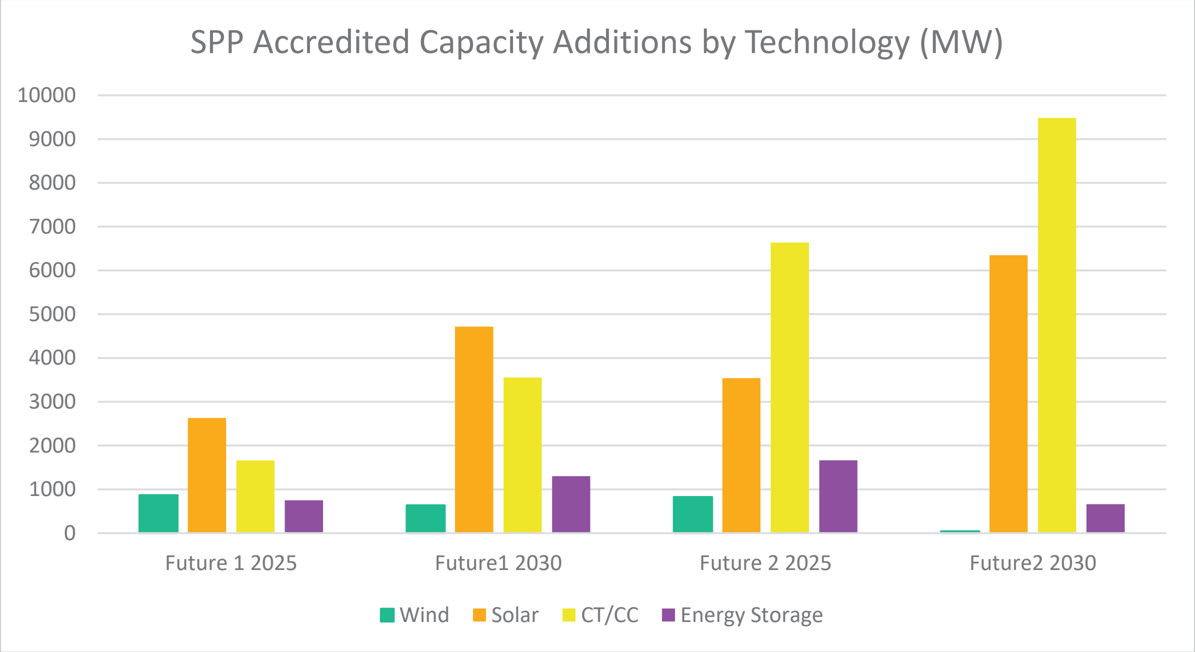


Figure 2.9: Accredited Capacity Additions by Technology

2.2.2.3 Siting Plan

SPP sited projected renewable and conventional resources according to various site attributes for each technology in accordance with the ITP Resource Siting Manual.[12]

Distributed solar generation, an assumption in Future 2 only, was allocated to the top 10 percent of load buses for each load area on a pro rata basis utilizing load review data. SPP stakeholder feedback was considered in the selection of sites for this technology. Figure 2.10 and Figure 2.11 show the selected sites and allocation of distributed solar capacity across the SPP footprint in megawatts.

---

[12] Documented in the ITP Resource Siting Manual

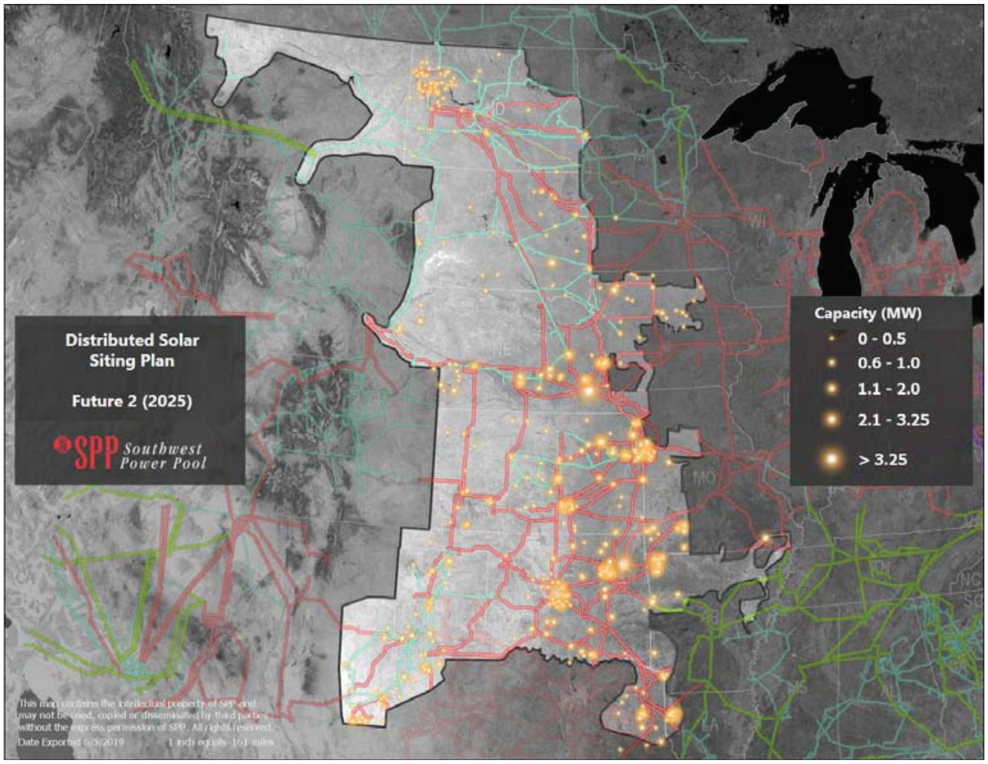


Figure 2.10: 2025 Future 2 Distributed Solar Siting Plan

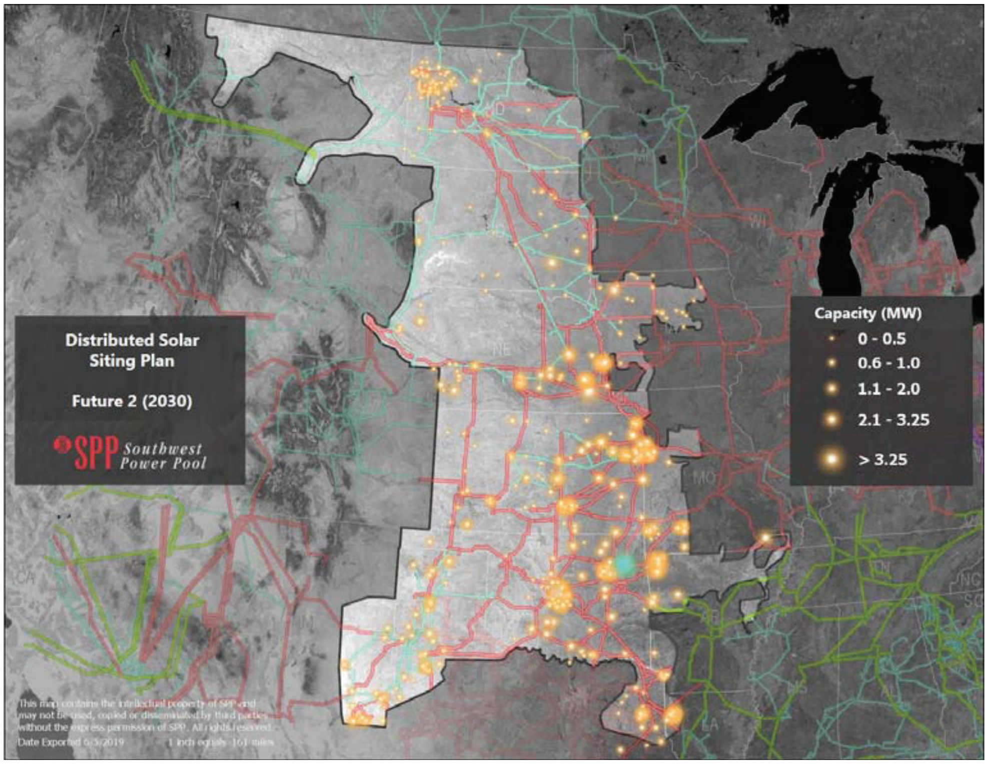


Figure 2.11: 2030 Future 2 Distributed Solar Siting Plan

Utility-scale solar was sited according to:

- Ownership by zone or by state
- Data Source (given preference in the following order)
    - SPP and Integrated System (IS) GI queue requests
    - Stakeholder submitted sites
    - Previous ITP sites
    - Other National Renewable Energy Laboratory (NREL) conceptual sites
- Capacity factor
- Generator transfer capability of the potential sites

Following the implementation of this ranking criteria, stakeholders could request exceptions to the results, which were reviewed for potential inclusion in the siting plan. Figure 2.12 through Figure 2.15 show the selected sited and allocation of utility solar capacity across the SPP footprint in megawatts.

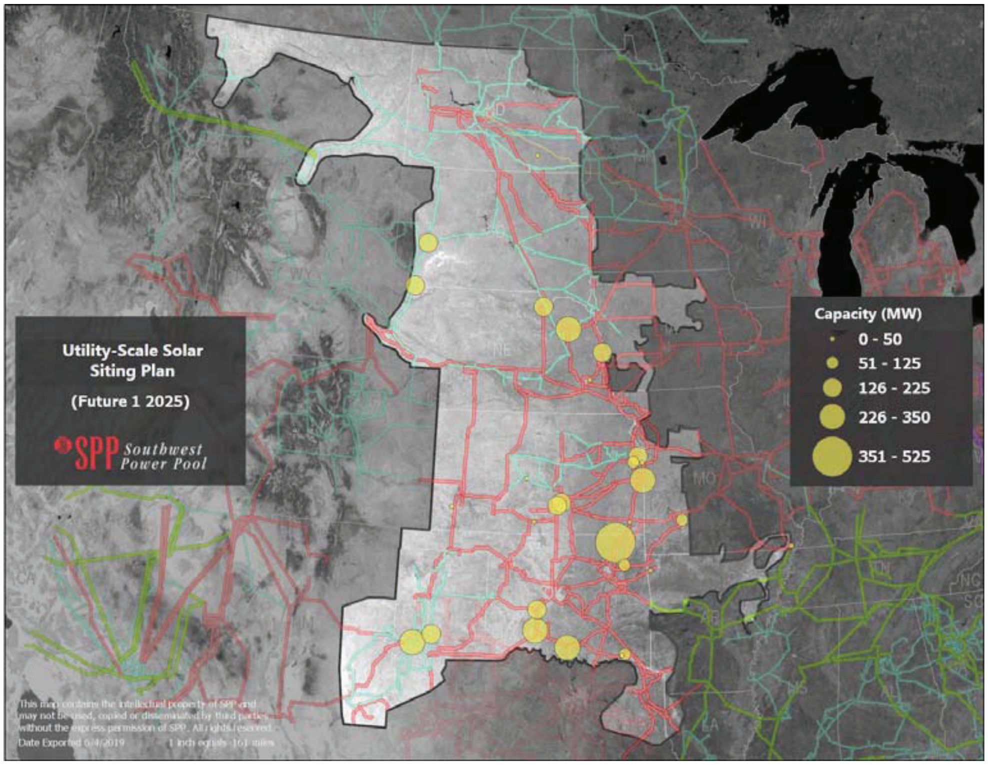


Figure 2.12: 2025 Future 1 Utility-Scale Solar Siting Plan

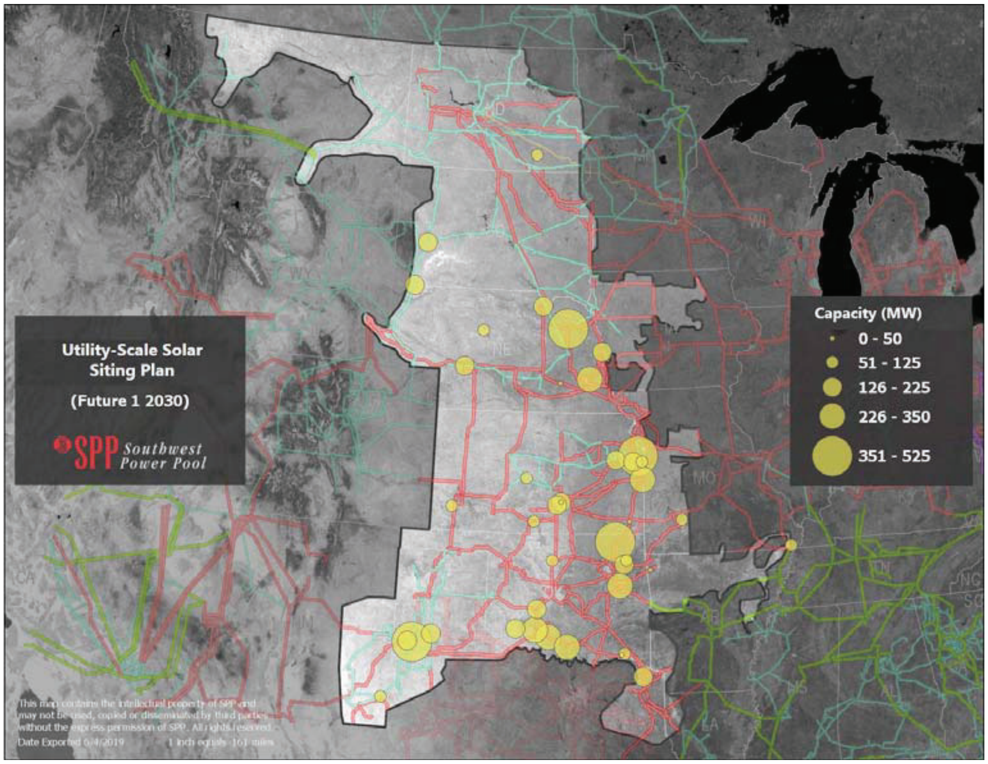


Figure 2.13: 2030 Future 1 Utility-Scale Solar Siting Plan

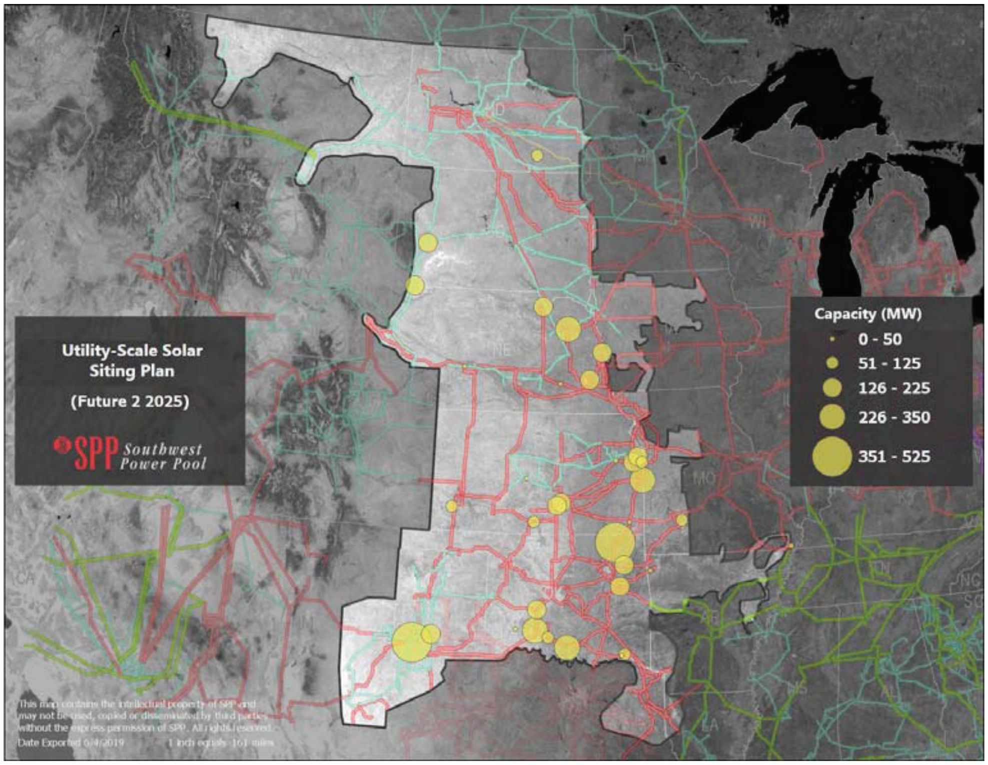


Figure 2.14: 2025 Future 2 Utility-Scale Solar Siting Plan

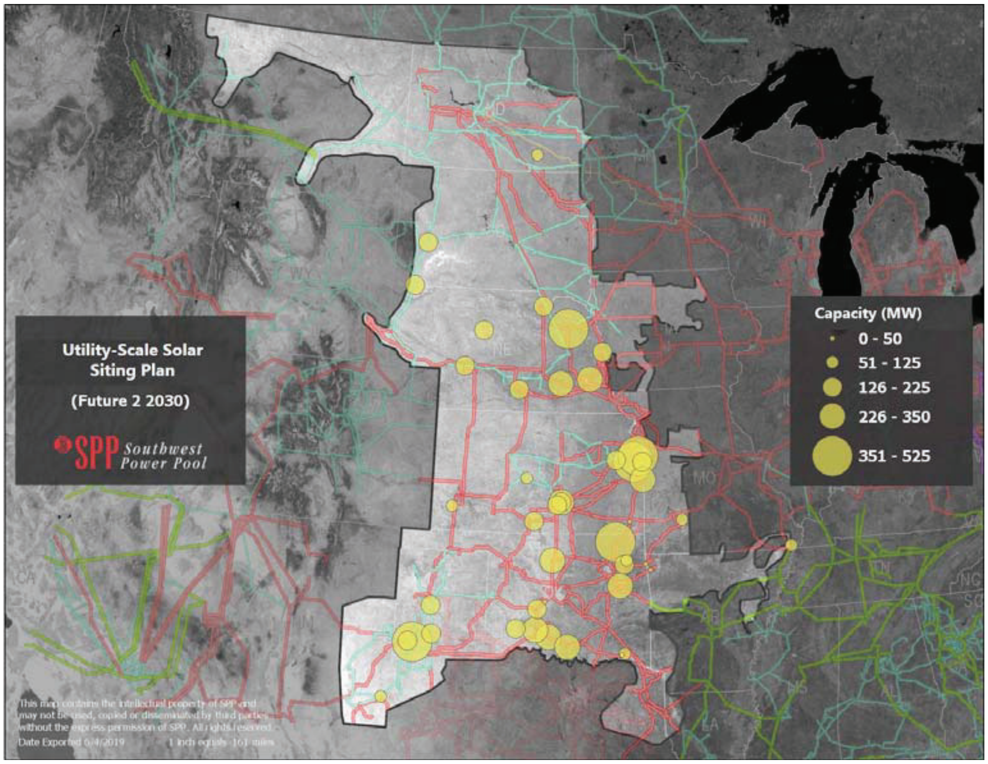


Figure 2.15: 2030 Future 2 Utility-Scale Solar Siting Plan

Wind sites were selected from GI queue requests that required the lowest total interconnection cost[13] per megawatt of capacity requested, taking into consideration the following:

- Potentially directly-assigned upgrade needed
- Unknown third-party system impacts
- Required generator outlet facilities (GOF)
- Generator Interconnection Agreement (GIA) suspension status

GI queue requests that did not have costs assigned were also considered with respect to their generator outlet capability, scope of related GOFs needed, and relation to recurring issues within the GI grouping.

Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which were reviewed for potential inclusion in the siting plan. Figure 2.16 through Figure 2.19 show the selected siting and allocation of wind capacity across the SPP footprint in megawatts.

---

[13] The total interconnection costs includes the total costs assigned for all interconnection related upgrades and network upgrade.

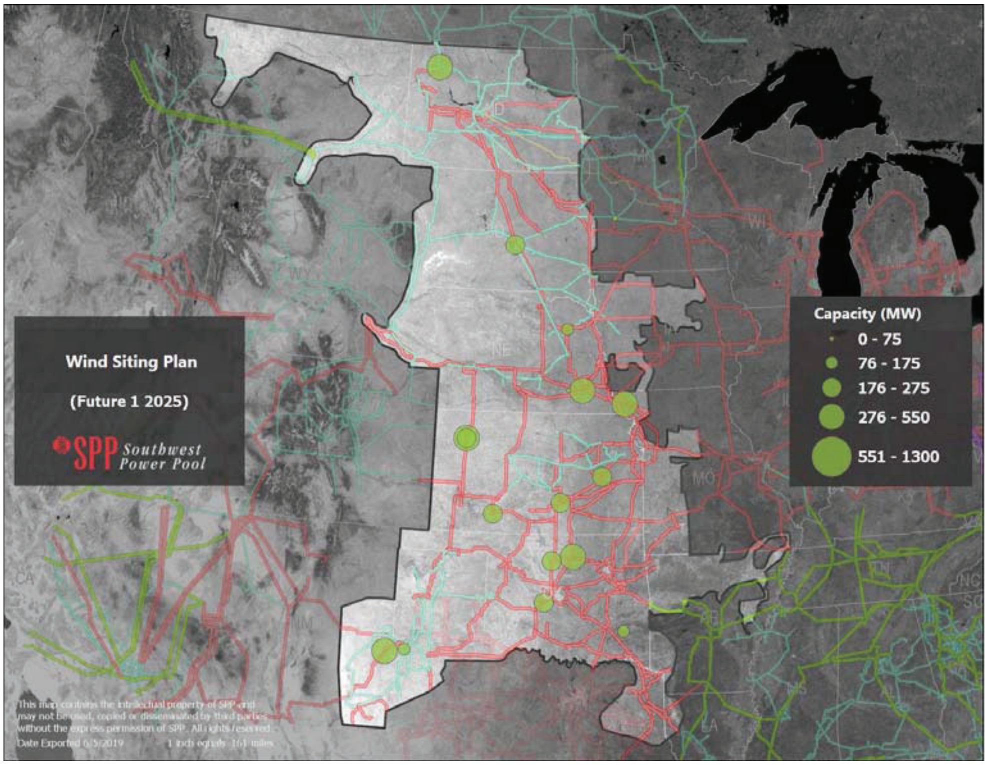


Figure 2.16: 2025 Future 1 Wind Siting Plan

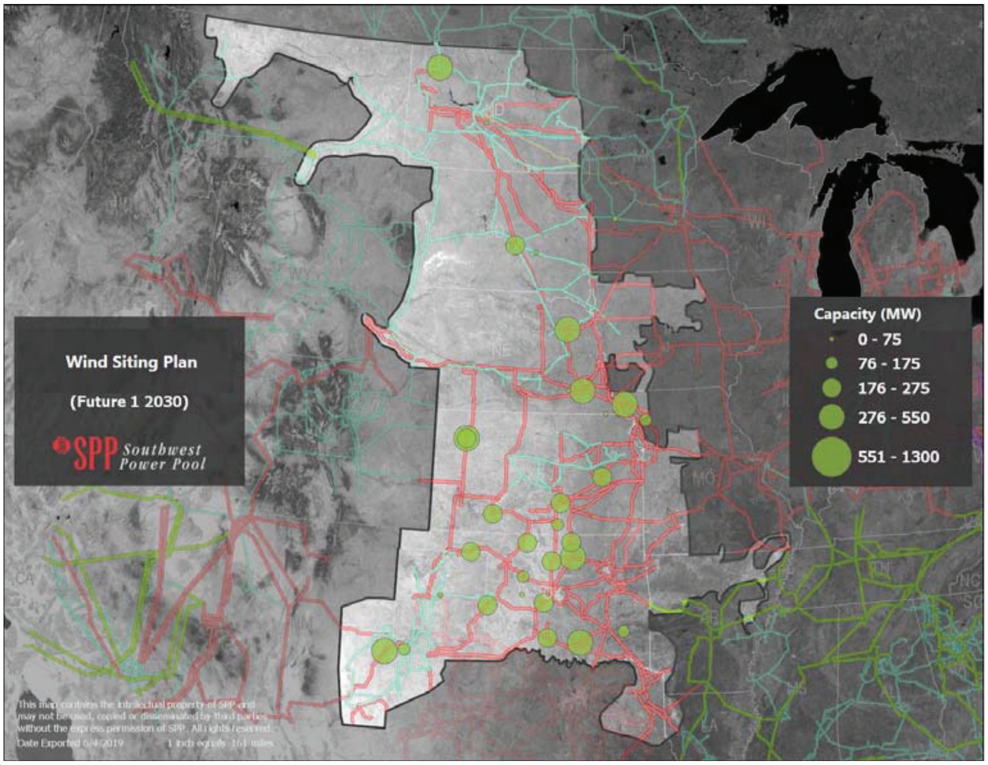


Figure 2.17: 2030 Future 1 Wind Siting Plan

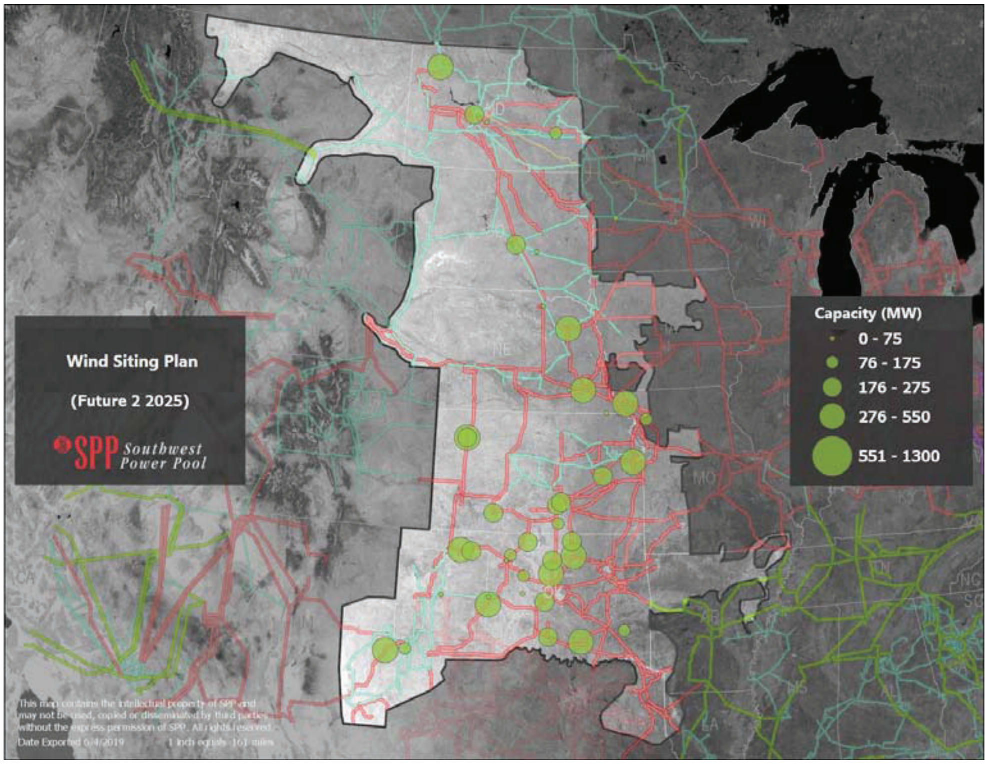


Figure 2.18: 2025 Future 2 Wind Siting Plan

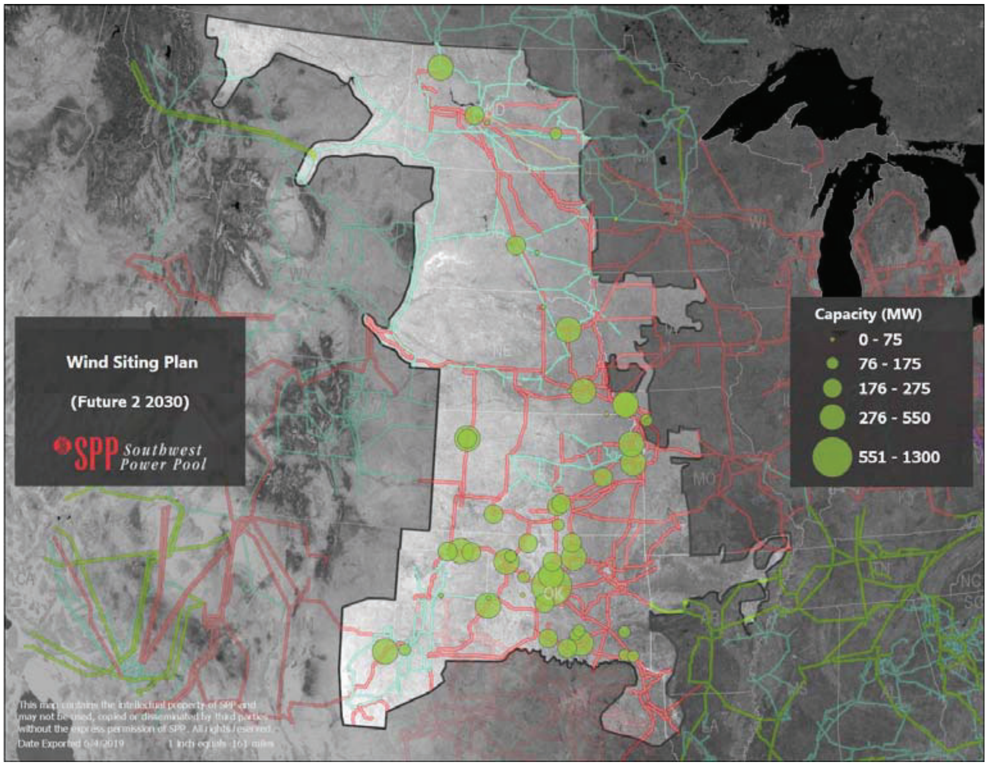


Figure 2.19: 2030 Future 2 Wind Siting Plan

Conventional generation was sited according to the zone of majority ownership, stakeholder preferences, generator outlet capability, scope of GOFs needed, and preference for existing and assumed retirement sites over previous ITP sites. Total conventional capacity at a given site (including existing) was limited to 1,500 MW. Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which were reviewed for potential inclusion in the siting plan. Figure 2.20 through Figure 2.23 show the selected sites for conventional generation across the SPP footprint.

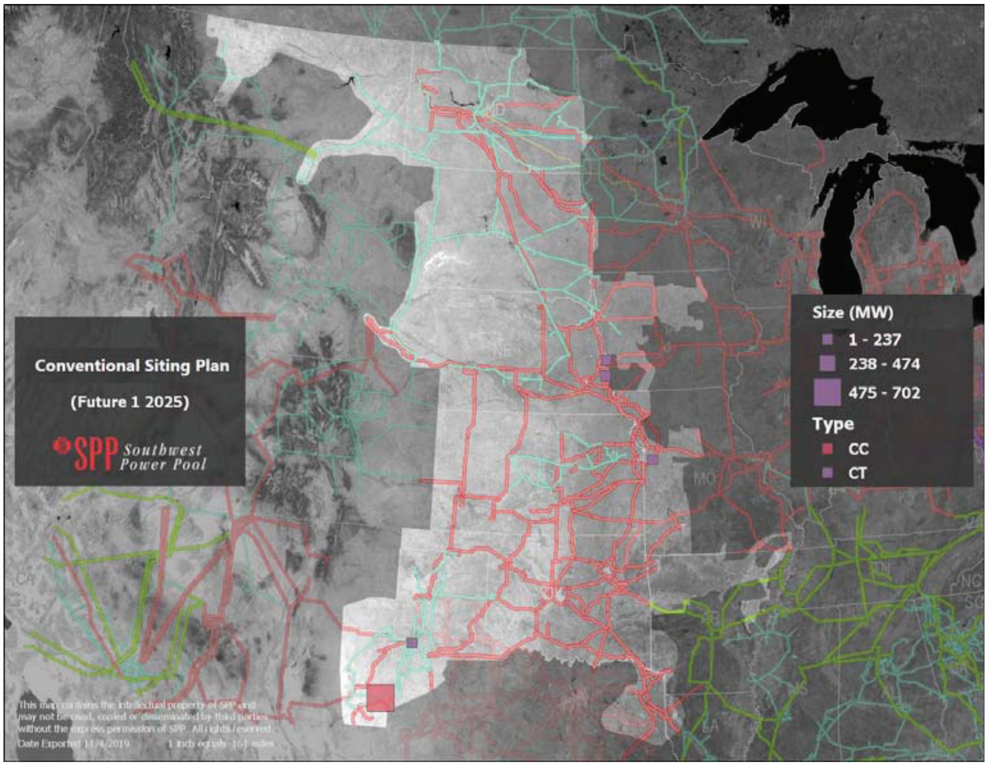


Figure 2.20: 2025 Future 1 Conventional Siting Plan

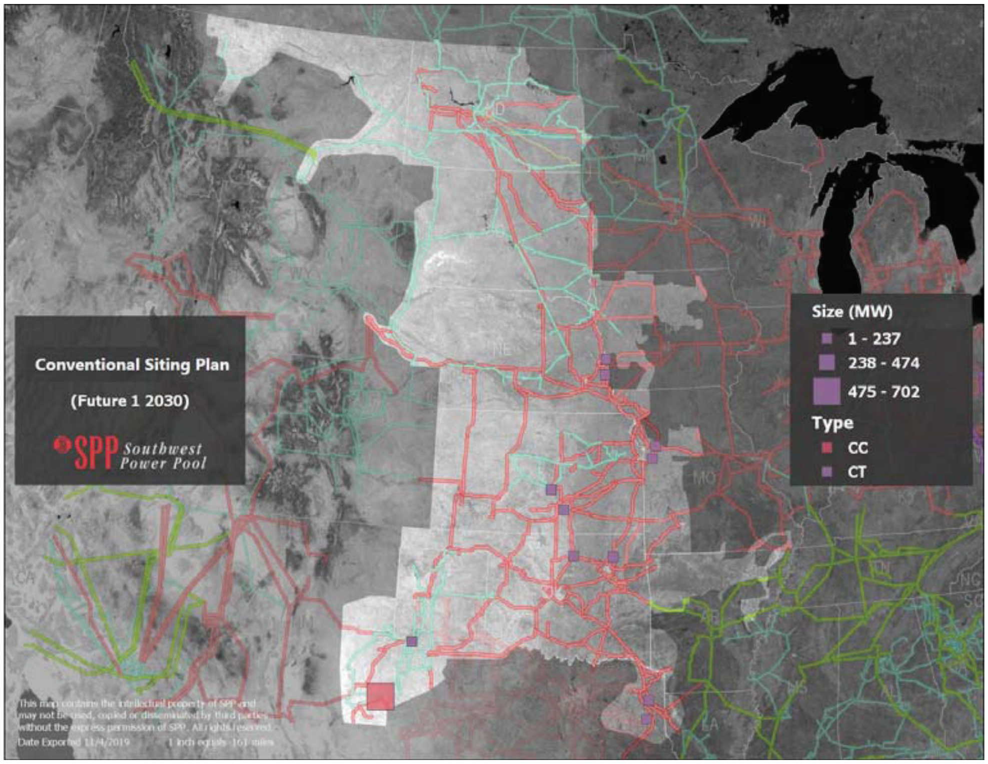


Figure 2.21: 2030 Future 1 Conventional Siting Plan

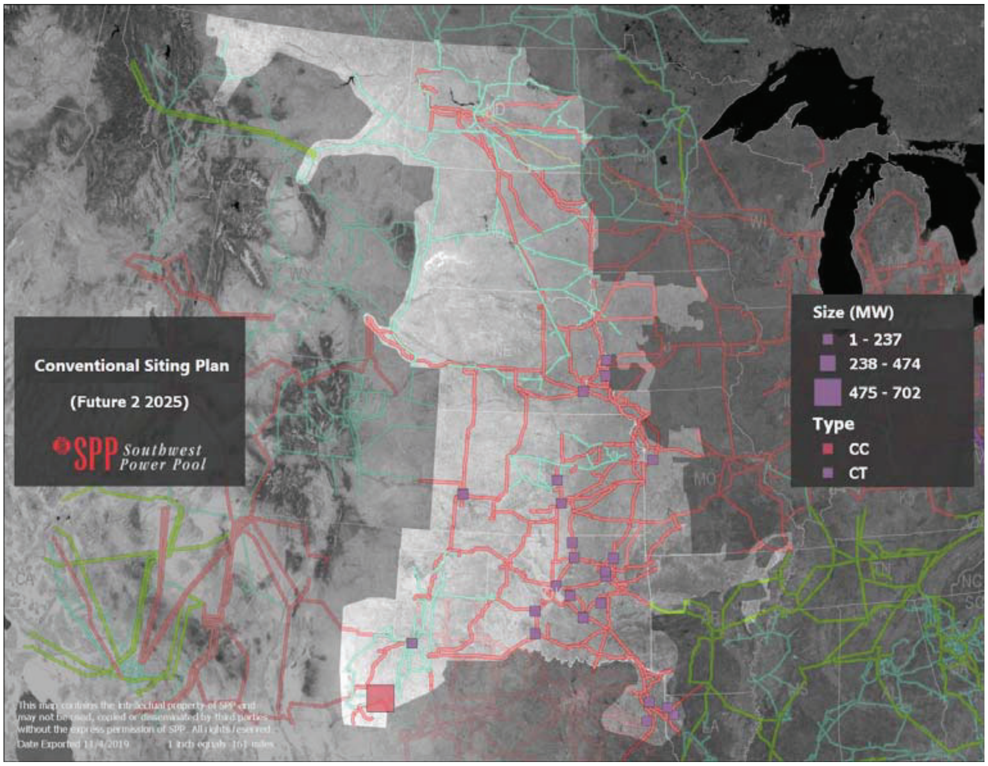


Figure 2.22: 2025 Future 2 Conventional Siting Plan

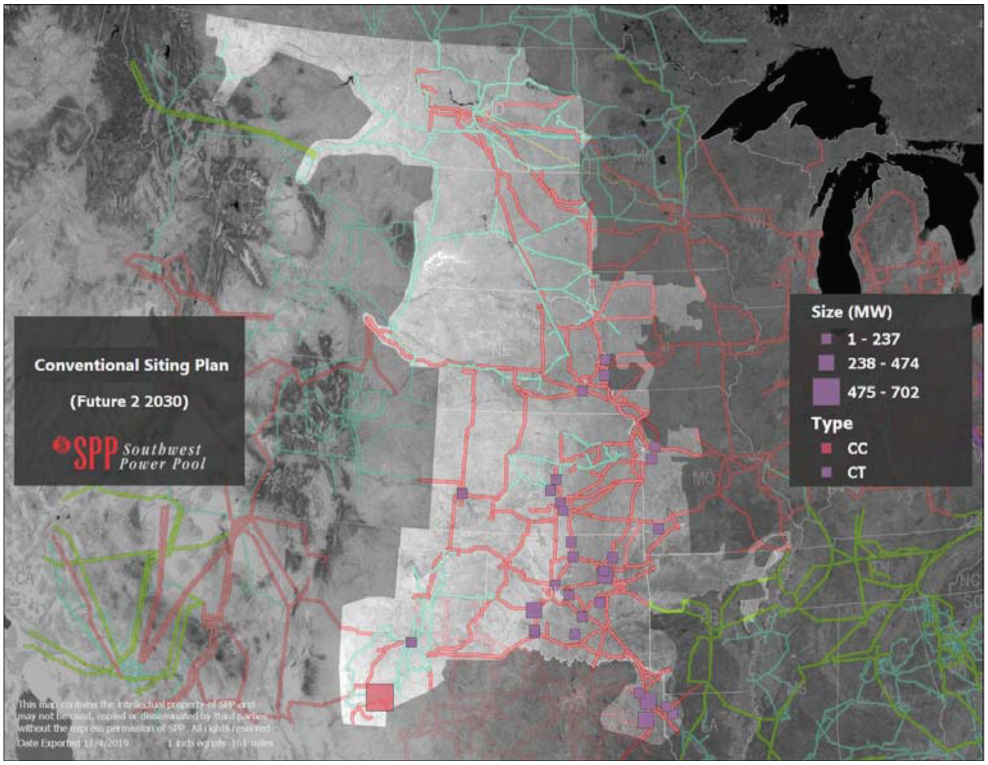


Figure 2.23: 2030 Future 2 Conventional Siting Plan

Battery sites were based on battery storage GI queue requests, the assumption that battery storage will largely be co-located with wind and solar, and transfer capability at available sites with consideration of the solar and wind siting plans. The siting of resources related to battery requests in the GI queue was limited to two-thirds of projected capacity due to the infancy of the technology in the industry. Two-thirds of projected battery capacity was associated with solar sites; one-third was associated with wind sites. For sites associated with battery requests, sited battery amounts were capped at the queue request amounts or siting availability. For sites not associated with existing battery GI requests, battery amounts were placed at wind and solar sites in increments of 20 megawatts and capped at siting availability. Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which were reviewed for potential inclusion in the siting plan. Figure 2.24 through Figure 2.27 show the selected sites for battery generation across the SPP footprint.

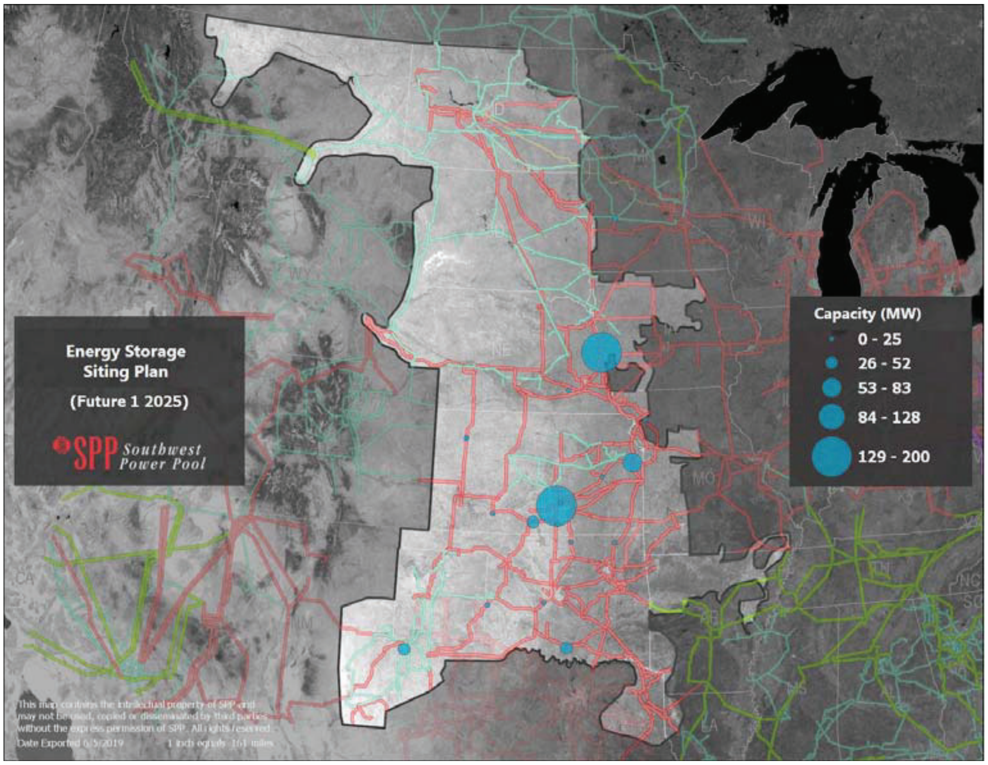


Figure 2.24: 2025 Future 1 Energy Storage Siting Plan

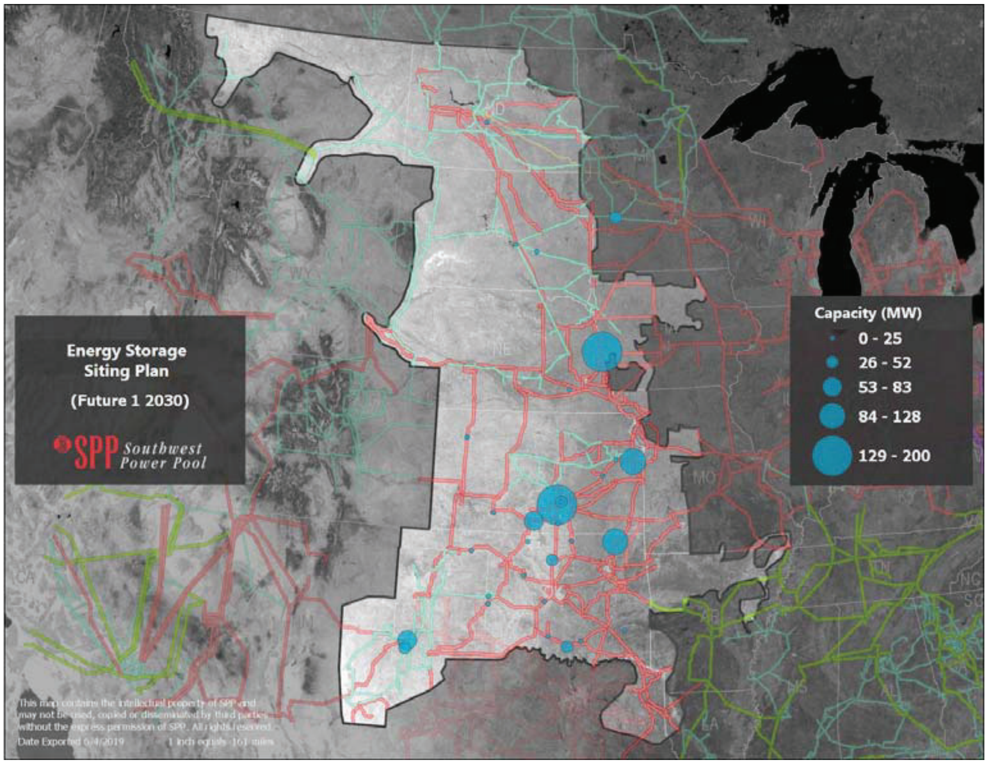


Figure 2.25: 2030 Future 1 Energy Storage Siting Plan

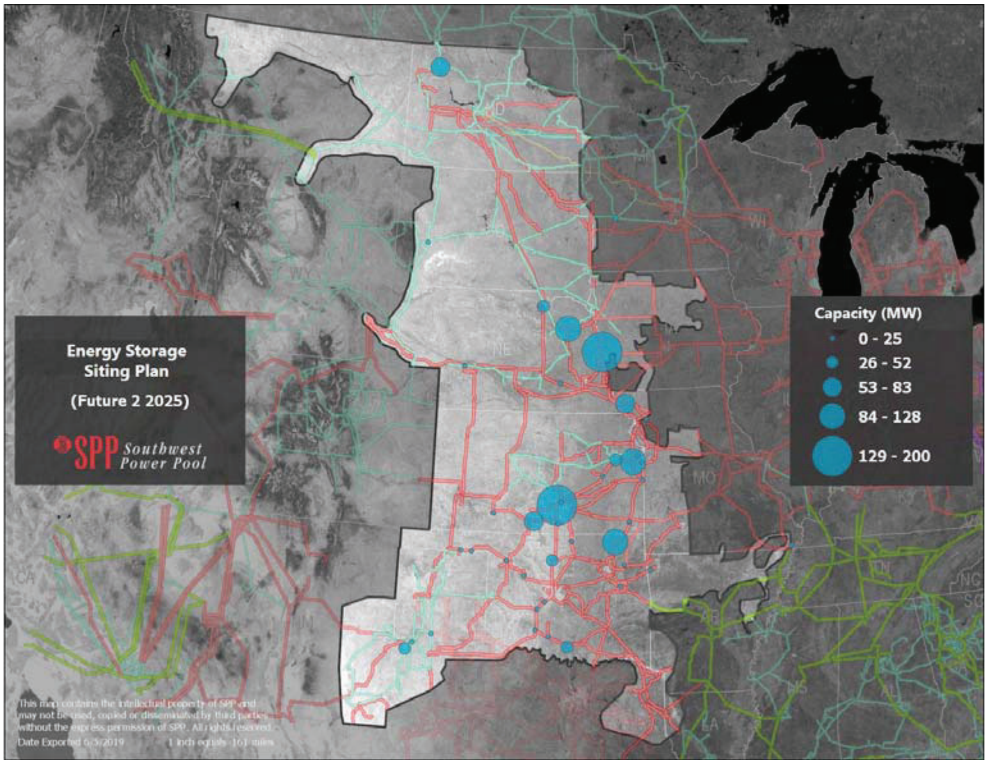


Figure 2.26: 2025 Future 2 Energy Storage Siting Plan

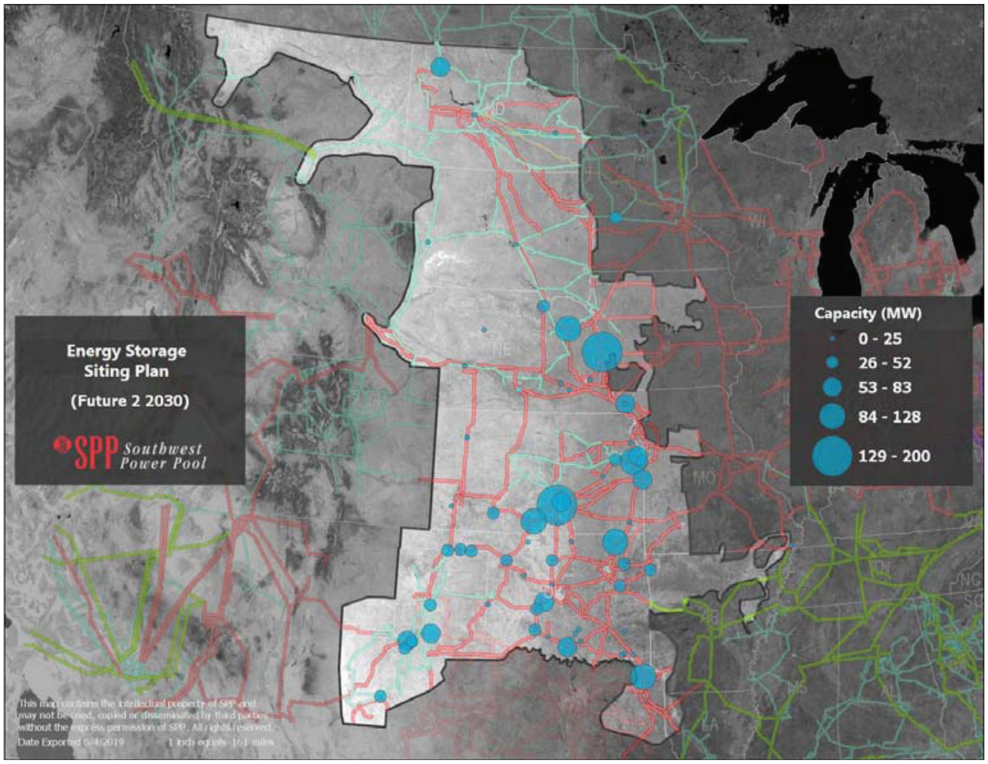


Figure 2.27: 2030 Future 2 Energy Storage Siting Plan

2.2.2.4 Generator Outlet Facilities (GOF)

To incorporate the siting plan into the market models, generator outlet facilities (GOFs) were necessary. GOFs are required such that overloads on the system were not identified due to the sited generation. The GOF selection process was intended as a proxy for the GI process. For sites with upgrades identified in a GI study, the associated upgrades were evaluated and potentially recommended as a GOF. In other instances, the site-specific results of the transfer analysis were assessed to determine if a site was capable of reliably allowing a resource to dispatch to the SPP system (siting availability). The results of the GOF analysis determined the upgrades shown in Table 2.4.

GOF Description	Site	MW Sited	GOF Source
Cleo Corner-Cleo Tap 138 kV terminal upgrades	Badger 345 kV Mooreland-Knob Hill 138 kV Hitchland 345 kV	376 MW (F1,Y10 & F2,Y5) 624 MW (F2, Y10)	GI Queue
Arbuckle 138 kV circuit 2 new tap	Blue River 138 kV Arbuckle-Blue River 138 kV	323 MW (F2, Y10)	GI Queue
Dover-Hennessey 138 kV terminal upgrades	Dover Switchyard 138 kV	288 MW (F2, Y5&Y10)	GI Queue
Tolk 345/230 kV second transformer	Crossroads 345 kV	522 MW	Siting Availability
Tolk-Crossroads-Eddy County 345 kV terminal upgrades			
Neset 345/230 kV replace transformer	Tande 345 kV	300 MW (F1, Y5&Y10), 374 MW (F2, Y5&Y10)	Siting Availability
Neset-Tande 230 kV rebuild			
Greenwood-Lee's Summit 161 kV rebuild	Greenwood 161 kV	237 MW	Siting Availability
Pleasant Hill-Lake Winnabago 161 kV terminal upgrades			
Hobbs-Andrews 230 kV voltage conversion	Sidewinder 345 kV	702 MW	Siting Availability
Andrews-Roadrunner 345 kV new line			

*Table 2.4: Generator Outlet Facilities *Sited amount for all futures/years unless otherwise noted*

2.2.2.5 External Regions

When developing renewable resource plans, SPP did not directly consider renewable policy requirements for external regions. However, the Midcontinent Independent System Operator (MISO) and Tennessee Valley Authority (TVA) renewable resource expansion and siting plans were based on the 2019 MISO Transmission Expansion Planning (MTEP19) continued fleet change (CFC) and accelerated fleet change (AFC) futures. Associated Electric Cooperative Inc. (AECI) renewable resource expansion plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI.

Conventional resource plans were incorporated for external regions included in the market simulations. Each region was surveyed for load and generation and assessed to determine the capacity shortfall. The MISO and TVA resource expansion and siting plans were based on the MTEP19 CFC and AFC futures, while AECI resource expansion and siting plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI. Figure 2.28 and Figure 2.29 show the cumulative capacity additions in 2030 by unit type of these external regions for Futures 1 and 2.

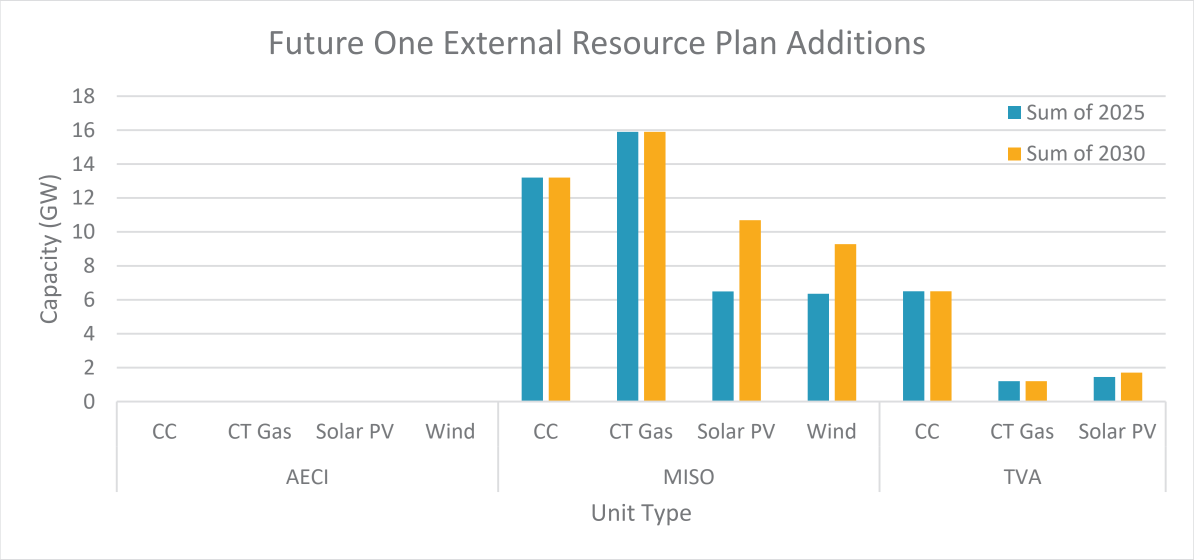


Figure 2.28: Capacity Additions by Unit Type-Future 1

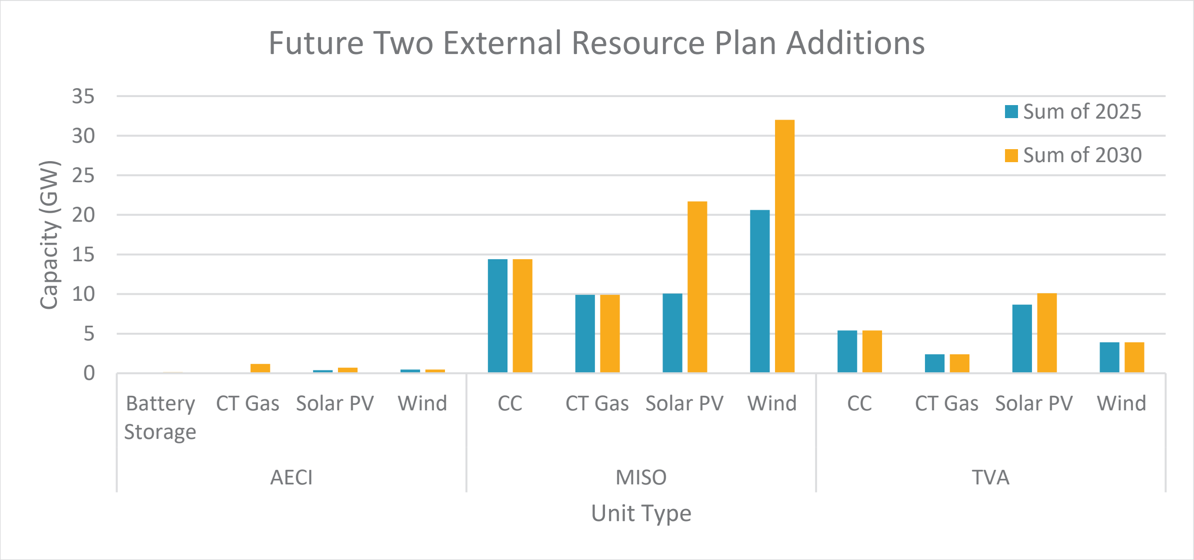


Figure 2.29: Capacity Additions by Unit Type-Future 2

2.2.3 CONSTRAINT ASSESSMENT

SPP considers transmission constraints when reliably managing the flow of energy across physical bottlenecks on the transmission system in the least-costly manner. Developing these study-specific constraints plays a critical part in determining transmission needs, as the constraint assessment identifies future bottlenecks and fine-tunes the market economic models.

SPP conducted an assessment to develop the list of transmission constraints used in the security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) analysis for all futures and study years. The TWG reviewed and approved elements identified in this assessment as limiting the incremental transfer of power throughout the transmission system, both under system intact and contingency situations. SPP staff defined the initial list of constraints leveraging the SPP permanent flowgate list,[14] which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real-time.

MTEP19 constraints were used to help evaluate and validate constraints identified within MISO and other neighboring areas. Constraints identified in neighboring areas were considered for inclusion as a part of the ITP study constraint list.

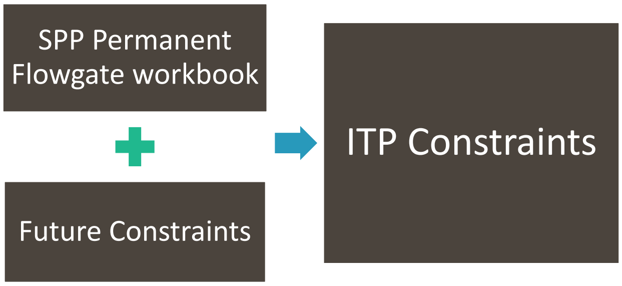


Figure 2.30: Constraint Assessment Process

2.3 MARKET POWERFLOW MODEL

The economic dispatch from each market economic model was used to develop market powerflow model snapshots representing stressed conditions on the SPP transmission system. Table 2.5 shows the peak and off-peak reliability hours as defined in the ITP Manual from each future and year of the market economic model simulations chosen for the market powerflow models.

	Off-Peak Hour	Wind Penetration[15]	Peak Hour	SPP Load (MW)
Future 1 2022	April 3 at 4:00 AM	92.3%	August 27 at 6:00 PM	51,639
Future 1 2025	April 5 at 1:00 AM	103.2%	July 23 at 6:00 PM	52,534
Future 1 2030	April 1 at 1:00 AM	110.7%	July 24 at 6:00 PM	53,216
Future 2 2025	April 5 at 1:00 AM	113.9%	July 23 at 6:00 PM	52,433
Future 2 2030	April 1at 2:00 AM	133.5%	July 24 at 6:00 PM	53,210

Table 2.5: Reliability Hour Details

---

[14] Posted on SPP OASIS

[15] Wind Penetration = Potential Delivered Energy / Load

3 BENCHMARKING

3.1 POWERFLOW MODEL

SPP staff performed two benchmarks related to the 2020 ITP base reliability powerflow models. The first benchmark was a load and generation value comparison between the 2019 ITP and 2020 ITP base reliability powerflow models. The second benchmark was a load and generation value comparison between the 2020 ITP base reliability powerflow models and real-time operational data. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the summer and winter peak base reliability model load totals (2019 ITP versus 2020 ITP), as shown in Figure 3.1 and Figure 3.2.
- Comparison of the summer and winter peak base reliability model generation dispatch totals for years two, five and 10 (2019 ITP versus 2020 ITP), as shown in Figure 3.3 and Figure 3.4.
- Additionally, the year-10 summer and winter peak generator retirements in the 2020 ITP base reliability powerflow models are shown in Figure 3.5.

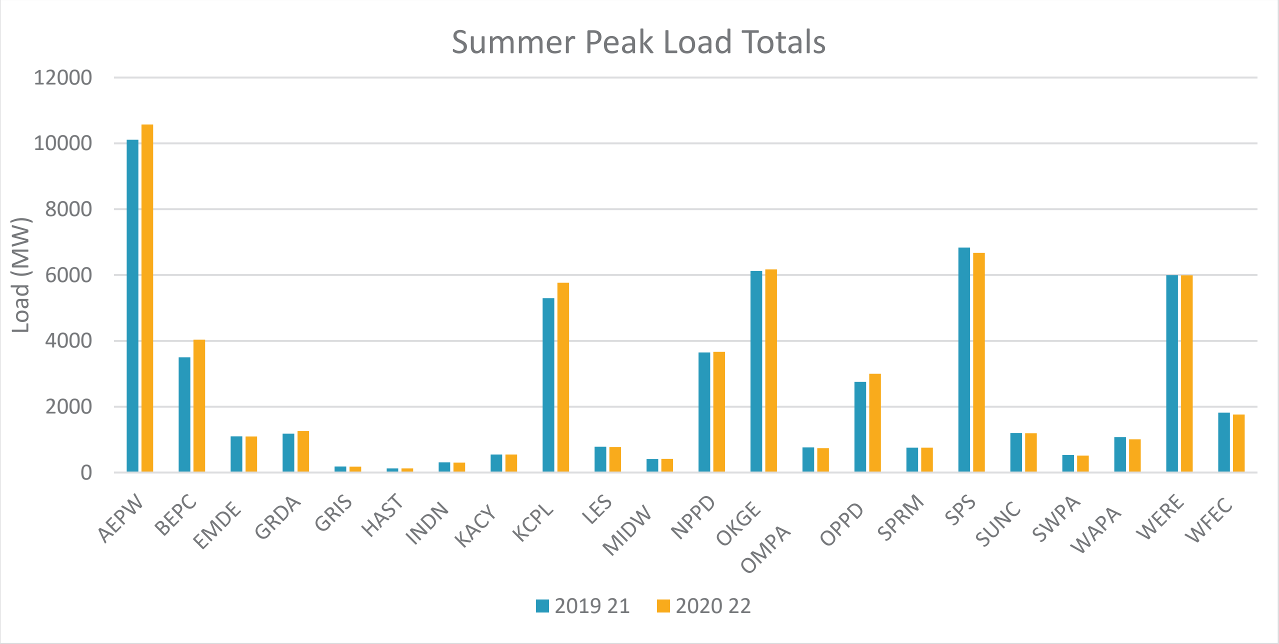


Figure 3.1: Summer Peak Year-Two Load Totals Comparison

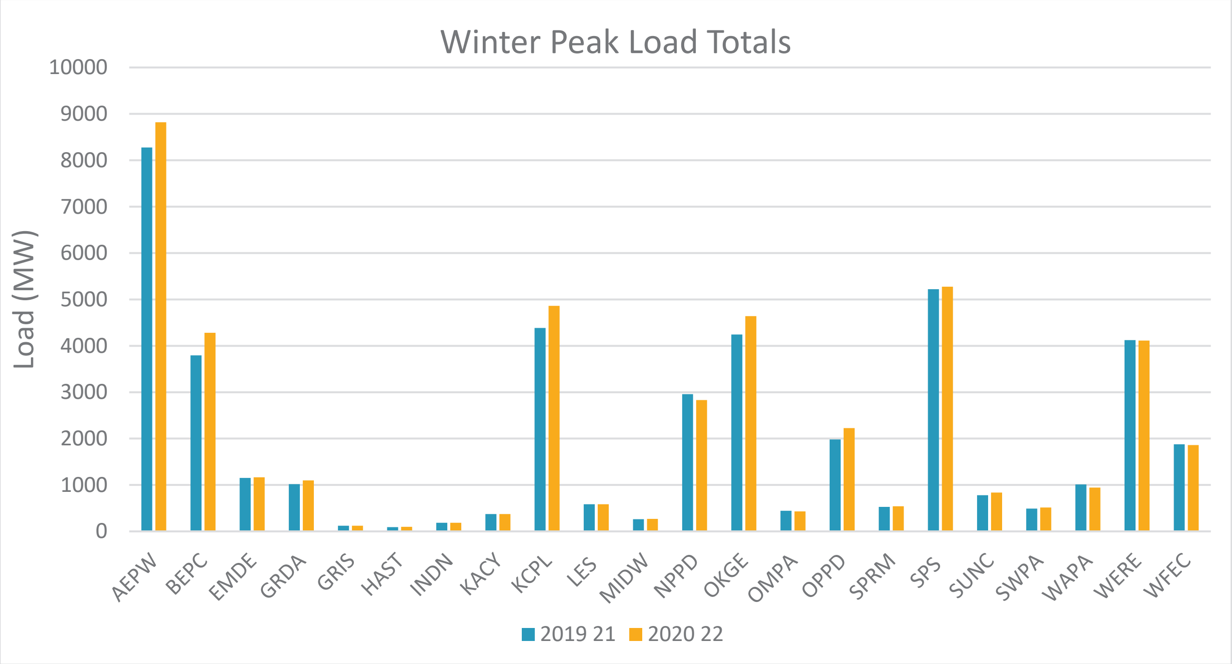


Figure 3.2: Winter Peak Year-Two Load Totals Comparison

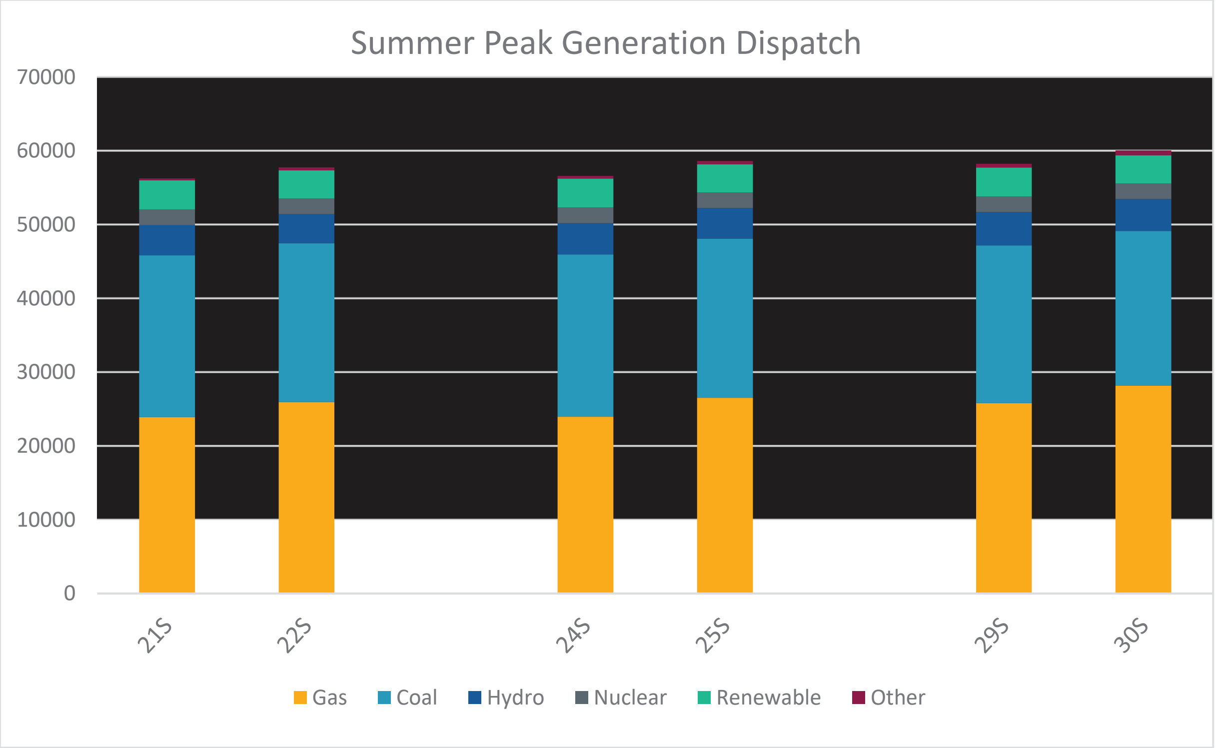


Figure 3.3: Summer Peak Years two, five and 10 Generation Dispatch Comparison

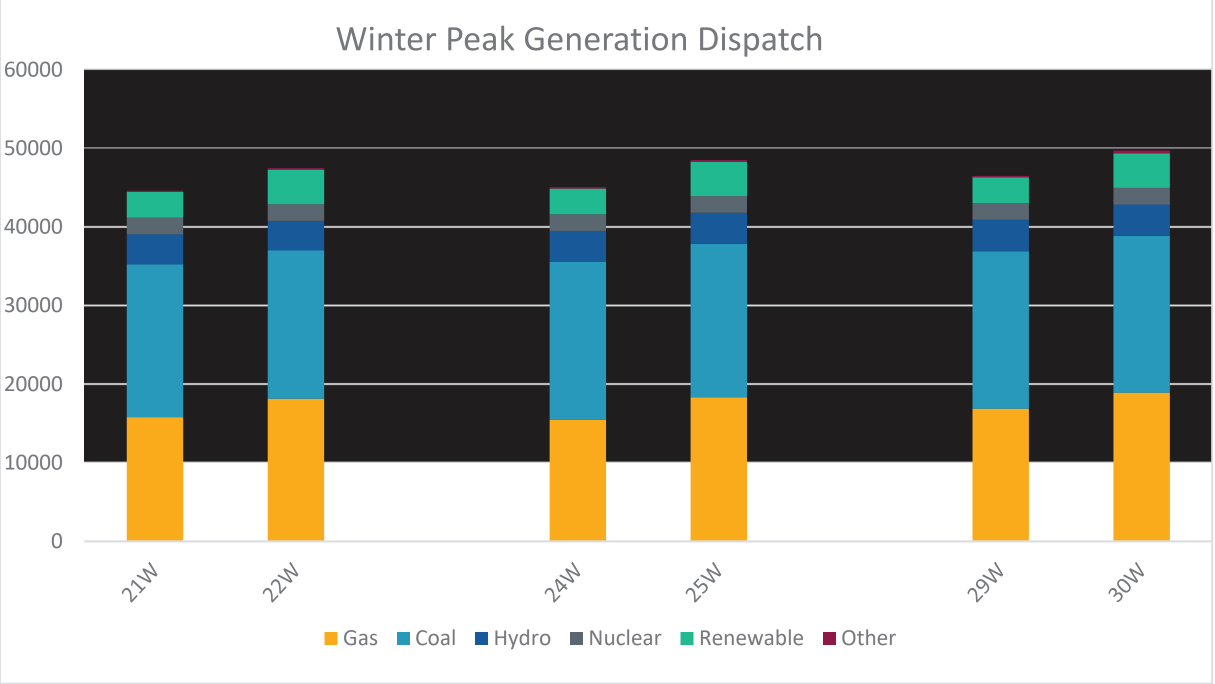


Figure 3.4: Winter Peak Years two, five and 10 Generation Dispatch Comparison

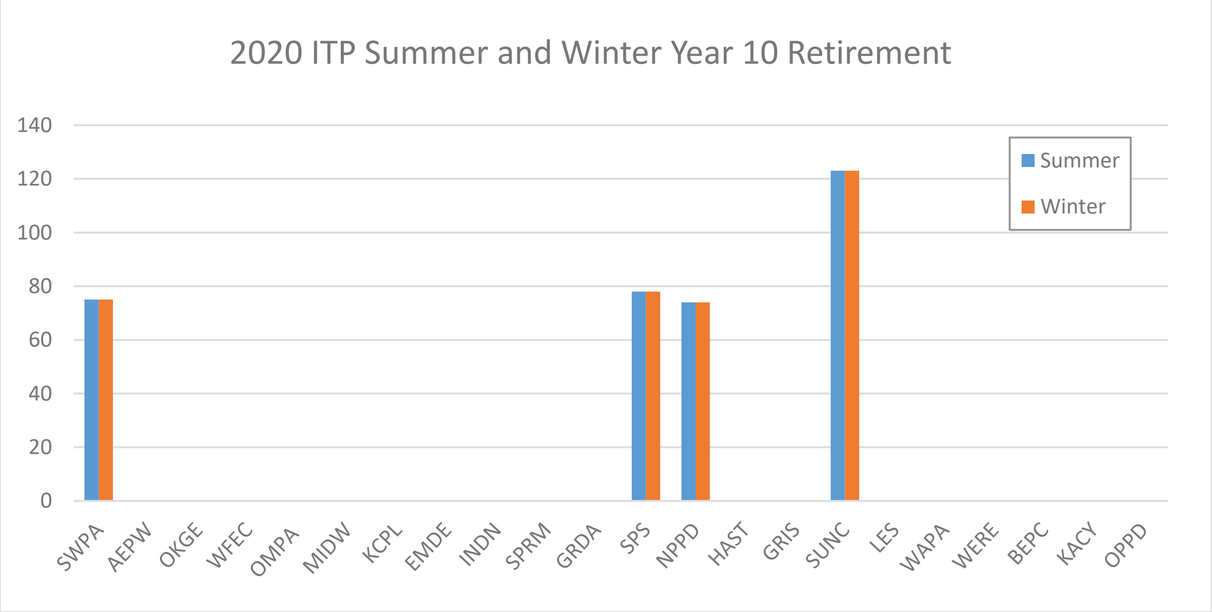


Figure 3.5: 2020 ITP Summer and Winter Year 10 Retirement

Operational model benchmarking for this assessment compared the 2020 summer and winter peak base reliability powerflow models against the real-time operational data for the 2019-2020 winter and 2020 summer timeframe. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the 2020 summer and winter load totals (base reliability model versus real-time operational data), as shown in Figure 3.6 and Figure 3.7

- Comparison of the 2020 summer and winter generation dispatch totals (base reliability model vs real-time operational data), as shown in Figure 3.8

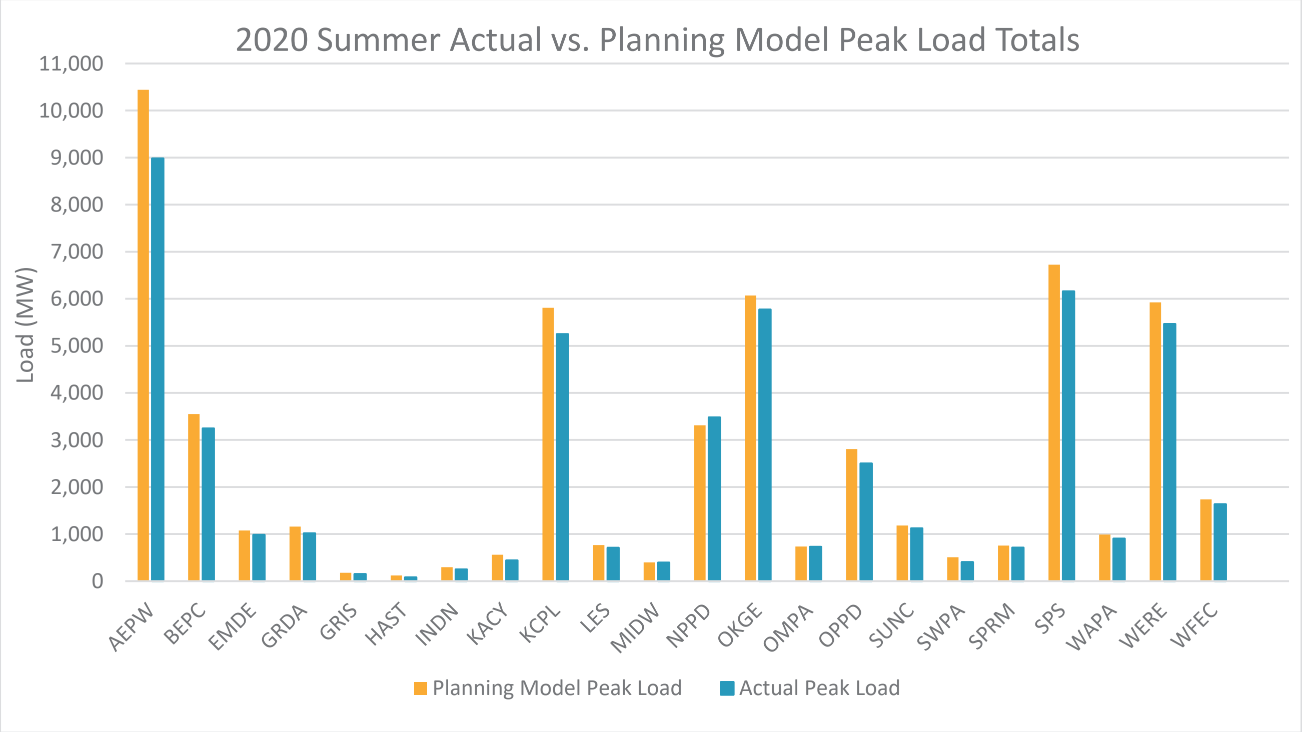


Figure 3.6: 2020 Summer Actual versus Planning Model Peak Load Totals

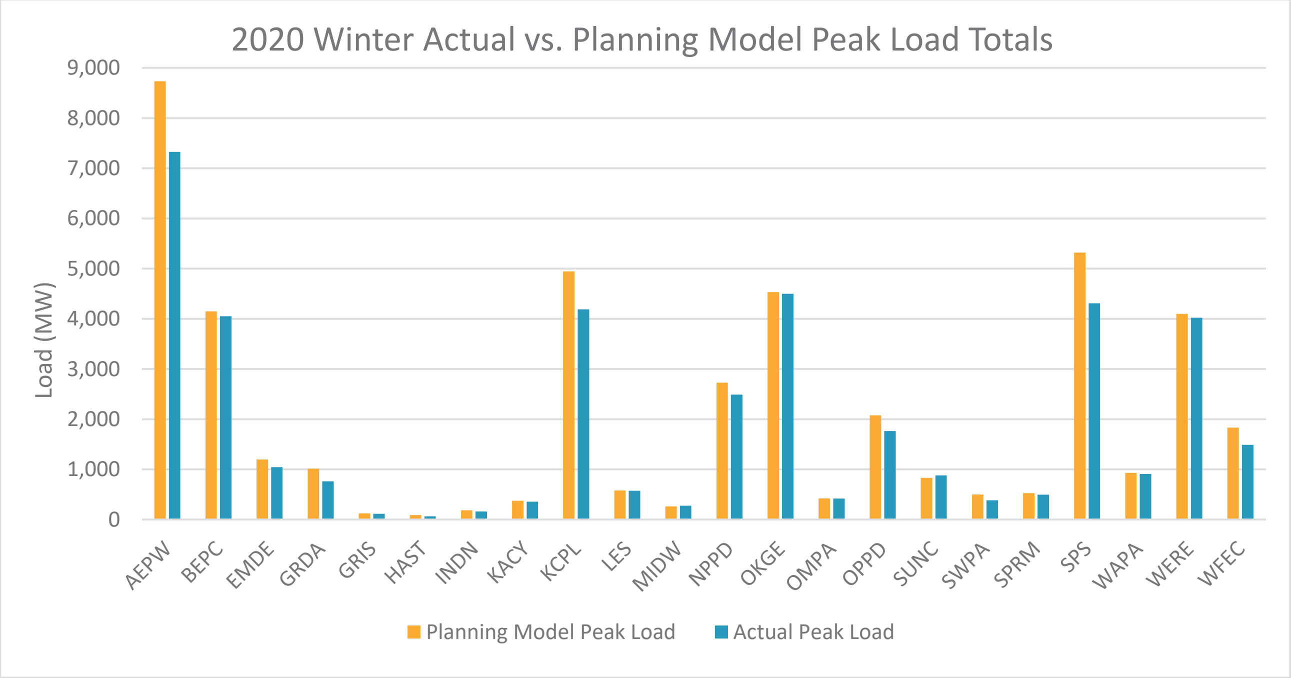


Figure 3.7: 2020 Winter Actual versus Planning Model Peak Load Totals

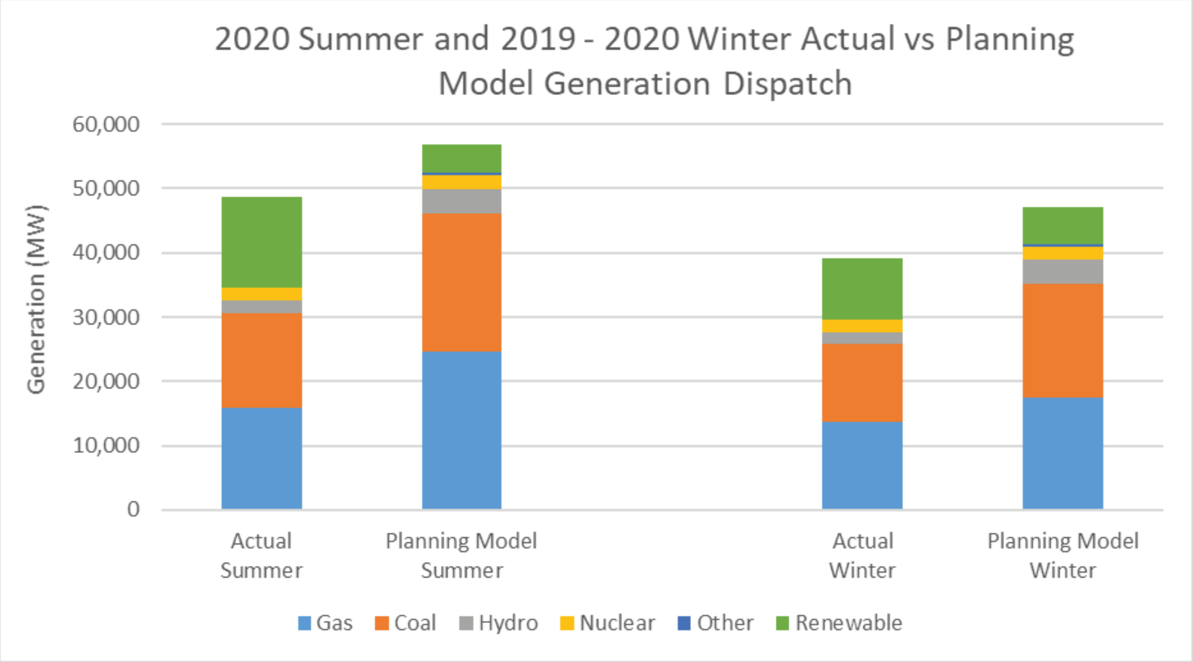


Figure 3.8: 2020 Actual versus Planning Model Generation Dispatch Comparison

3.2 MARKET ECONOMIC MODEL

Benchmarking for this study was performed on the year-two Future 1 market economic model. For the benchmarking process to provide the most value, it was important to compare the current study model against previous ITP modeling outputs and historical SPP real-time data. Numerous benchmarks were conducted to ensure the accuracy of the market economic modeling data, including:

- Comparing generation capacity factors with EIA data comparing simulated maintenance outages to SPP real-time data, and ensuring operating and spinning reserve capacities meet SPP Criteria
- Comparing generation capacity factors, generating unit average cost, renewable generation profiles, system locational marginal prices (LMP), adjusted production cost (APC), and interchange between the 2020 ITP and the 2019 ITP.

3.2.1 GENERATOR OPERATIONS

3.2.1.1 Capacity Factor by Unit Type

Comparing capacity factors is a method for measuring the similarity in planning simulations and historical operations. This benchmark provides a quality control check of differences in modeled outages and assumptions regarding renewable, intermittent resources.

When compared with capacity factors reported to the EIA for 2018 and resulting from the 2020 ITP study, the capacity factors for conventional generation units fell near the expected values. The difference in capacity factors between the datasets were attributed to differences in fuel and load forecasts as well as changes in the generation mix.

	Average Capacity Factor		
Unit Type	2018 EIA	2019 ITP Future 1 2021	2020 ITP Future 1 2022
Nuclear	93%	93%	90%
Combined Cycle	57%	41%	42%
CT Gas	12%	3%	4%
Coal	54%	61%	67%
ST Gas	14%	3%	4%
Wind	37%	46%	46%
Solar	26%	23%	24%

Table 3.1: Generation Capacity Factor Comparison

3.2.1.2 Average Energy Cost

Examining the average cost per MWh by unit type gives insight into what units will be dispatched first (without considering transmission constraints). Overall, the average costs per MWh were lower in the 2020 ITP than in the 2019 ITP due to the fuel and load forecasts and the difference in generation mix.

	Average Energy Cost ($/MWh)	
Unit Type	2019 ITP Future 1 2021	2020 ITP Future 1 2022
Nuclear	$15	$16
Combined Cycle	$31	$31
CT Gas	$44	$43
Coal	$24	$24
ST Gas	$41	$42

Table 3.2: Average Energy Cost Comparison

3.2.1.3 Generator Maintenance Outages

Generator maintenance outages in the simulations were compared to SPP real-time data. These outages have a direct impact on flowgate congestion, system flows and the economics of serving load.

The operations data includes certain outage types that cannot be replicated in these planning models. The difference in magnitude between the real-time data and the market economic simulated outages is due to the additional operational outages beyond those required by annual maintenance or driven by forced (unplanned) conditions. Although the market economic model simulation outages do not have as high a magnitude as the historical outages provided by SPP operations, the outage rates in the 2020 ITP are very similar to previous ITP assessments. The curves from the historical data and the market economic model simulations complemented each other very well in shape.

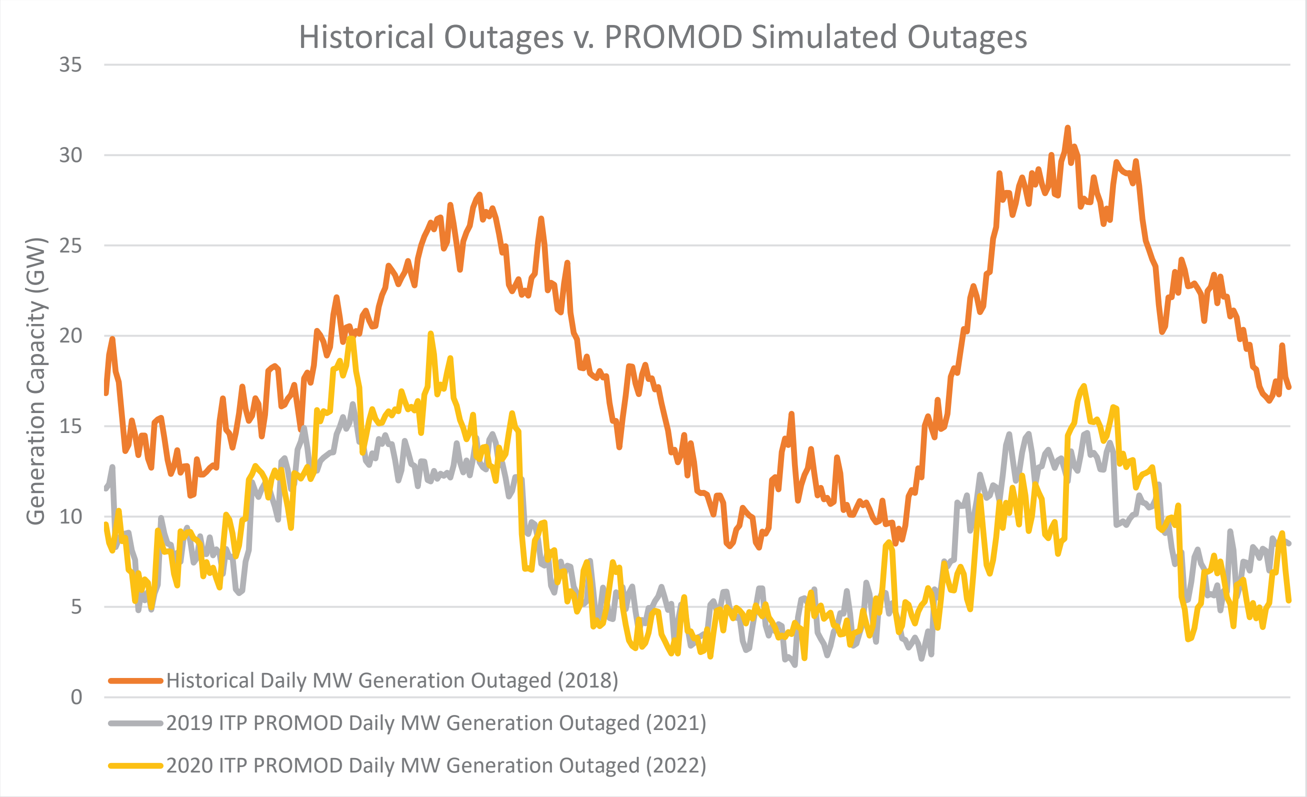


Figure 3.9: Historical Outages v. PROMOD Simulated Outages

3.2.1.4 Operating and Spinning Reserve Adequacy

Operating reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of unplanned unit outages. According to SPP Criteria, operating reserves should meet a capacity requirement equal to the sum of the capacity of largest unit in SPP and half of the capacity of the next largest unit in SPP. At least half of this requirement must be fulfilled by spinning reserve.

The operating reserve capacity requirement was modeled at 1,675 MW and spinning reserve capacity requirement was modeled at 823 MW. The reserve requirements were met in the market economic models.

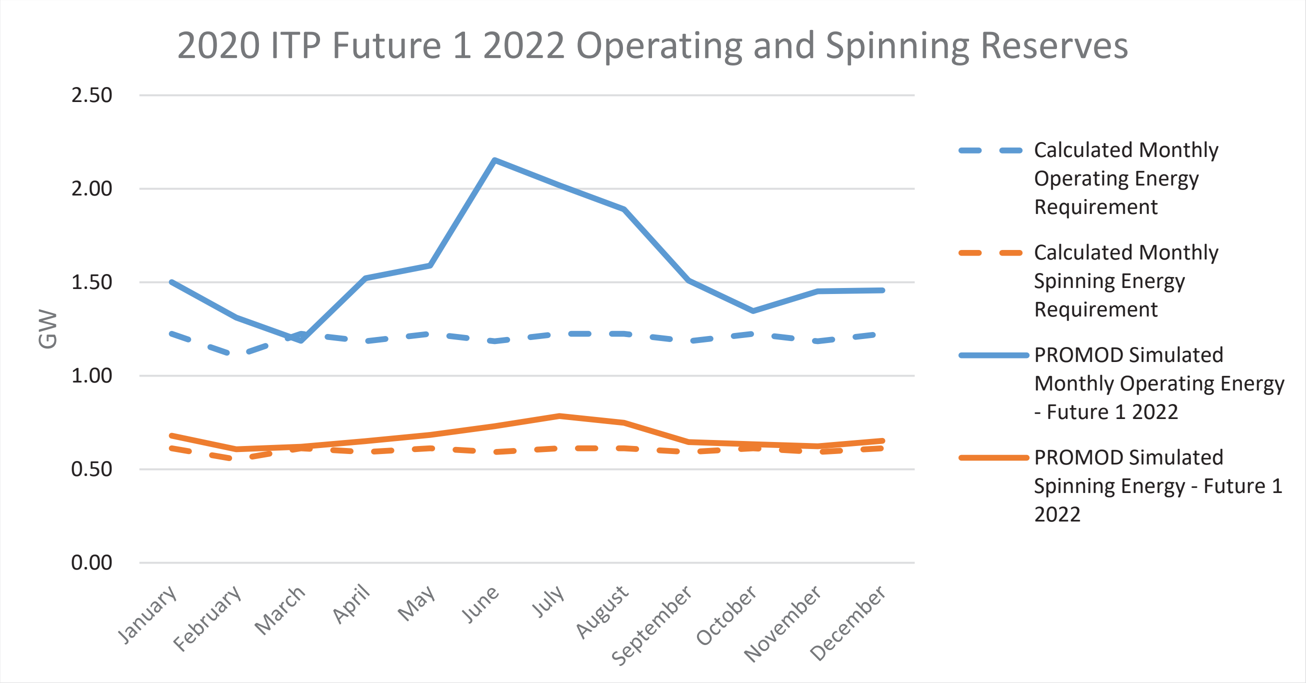


Figure 3.10: 2020 ITP Future 1 2022 Operating and Spinning Reserves

3.2.1.5 Renewable Generation

Wind and solar energy output is higher in the 2020 ITP than in the 2019 ITP because of additions identified during the generation review milestone. Wind output is noticeably greater due to the amount of installed capacity and approved RARs in 2020 ITP.

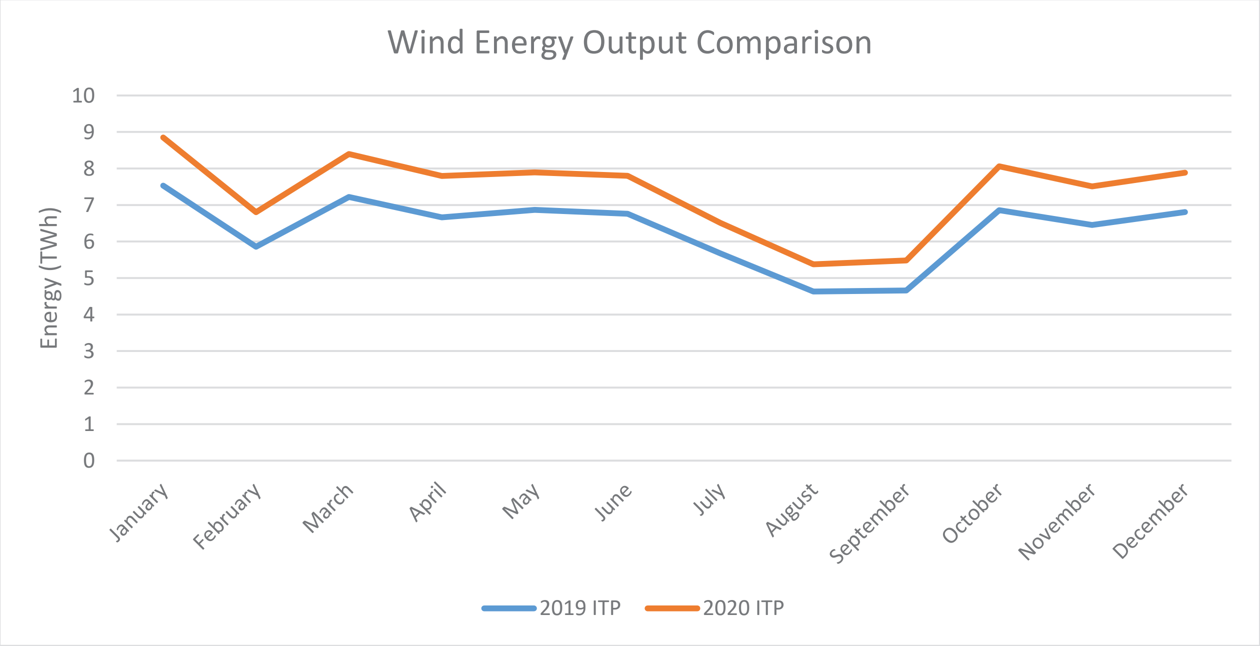


Figure 3.11: Wind Energy Output Comparison

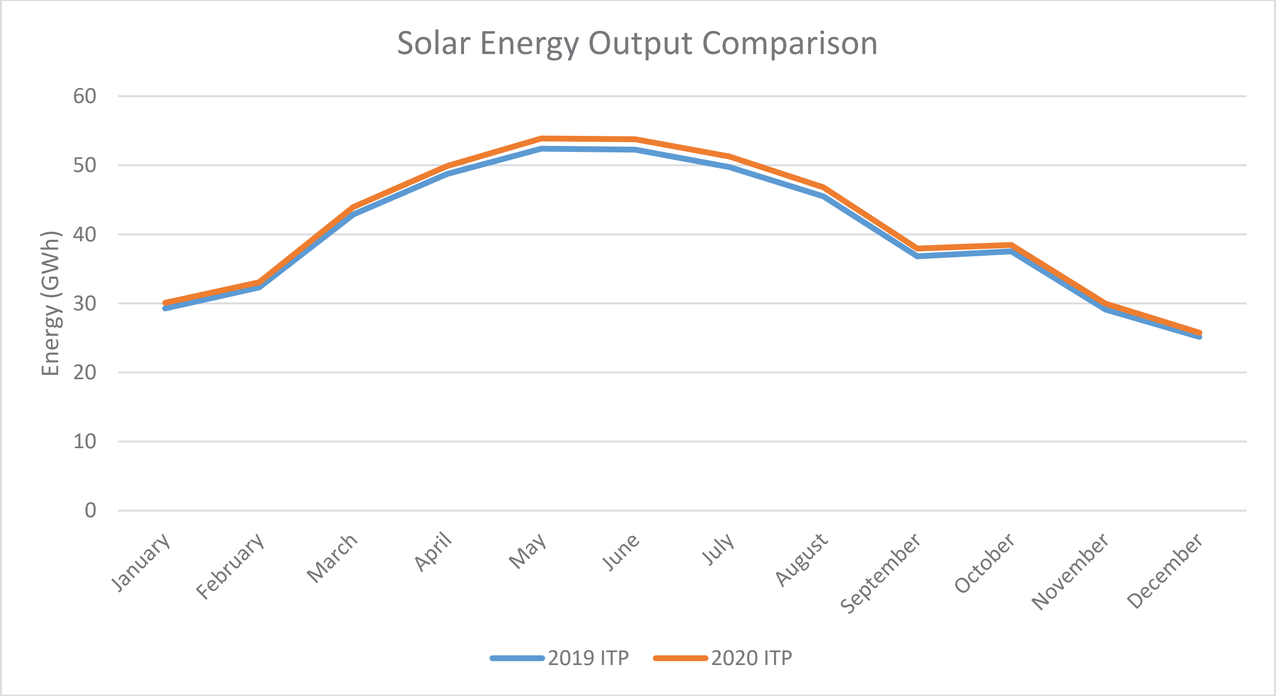


Figure 3.12: Solar Energy Output Comparison

3.2.2 SYSTEM LOCATIONAL MARGINAL PRICE (LMP)

Simulated LMPs were benchmarked against simulated LMPs from the 2019 ITP. This data was compared on an average monthly value-by-area basis. Figure 3.13 portrays the results of the benchmarking model for the SPP system. The decrease in LMPs in the 2020 ITP is due to a slight decrease in natural gas price fuel forecasts and additional renewable energy.

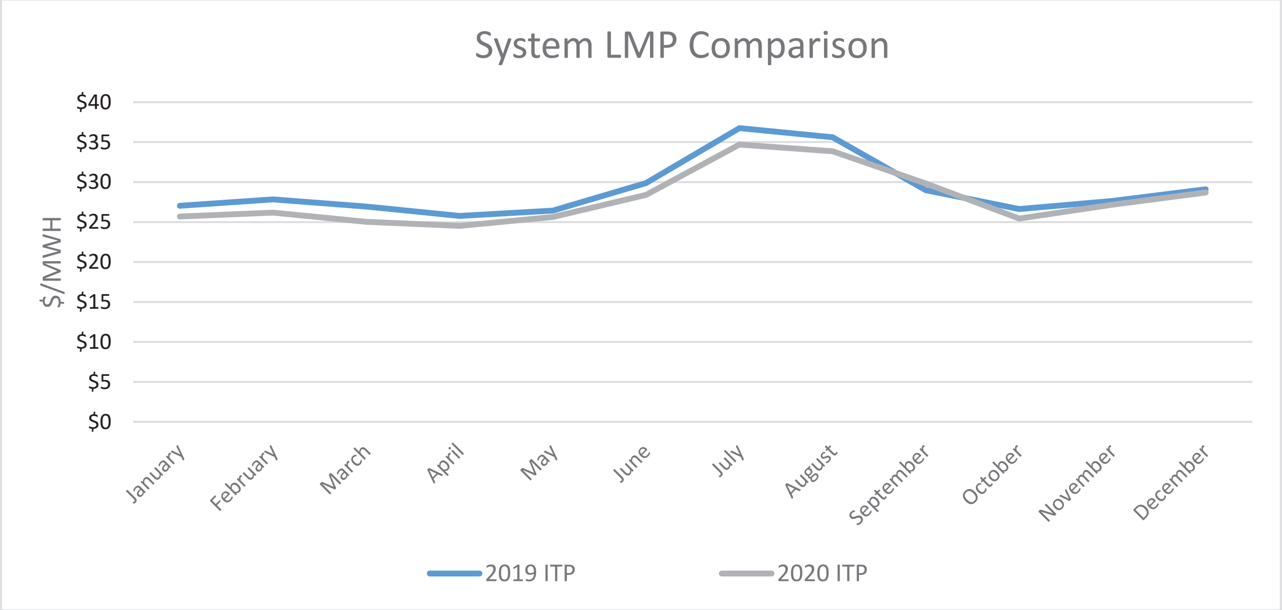


Figure 3.13: System LMP Comparison

3.2.3 ADJUSTED PRODUCTION COST (APC)

Examining the APC provides insight to which entities generally purchase generation to serve their load and which entities generally sell their excess generation. APC results for SPP zones were overall slightly lower in the 2020 ITP than in the 2019 ITP due to the change in fuel and renewable forecasts.

The APC on a zonal level both increases and decreases depending on the characteristics of the zone, including level of renewable increase, retirements and zonal load forecast changes. See Figure 3.14 and Figure 3.15 for a summary of regional and zonal APC results.

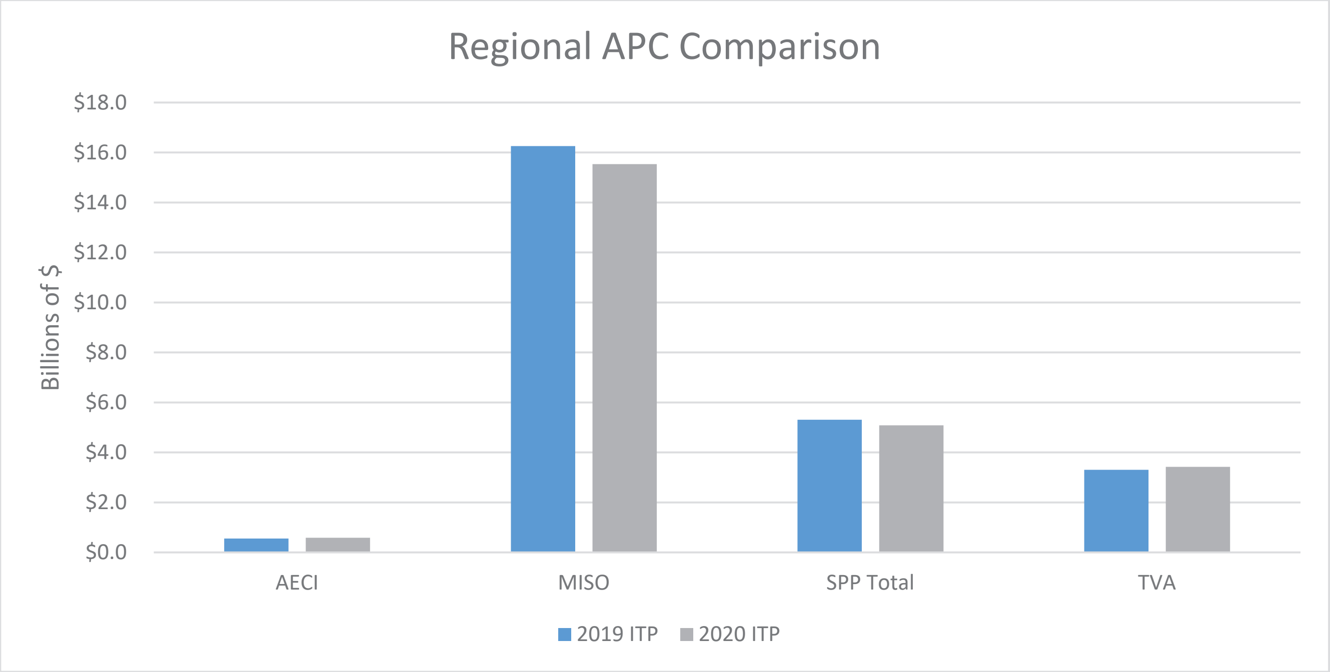


Figure 3.14: Regional APC Comparison

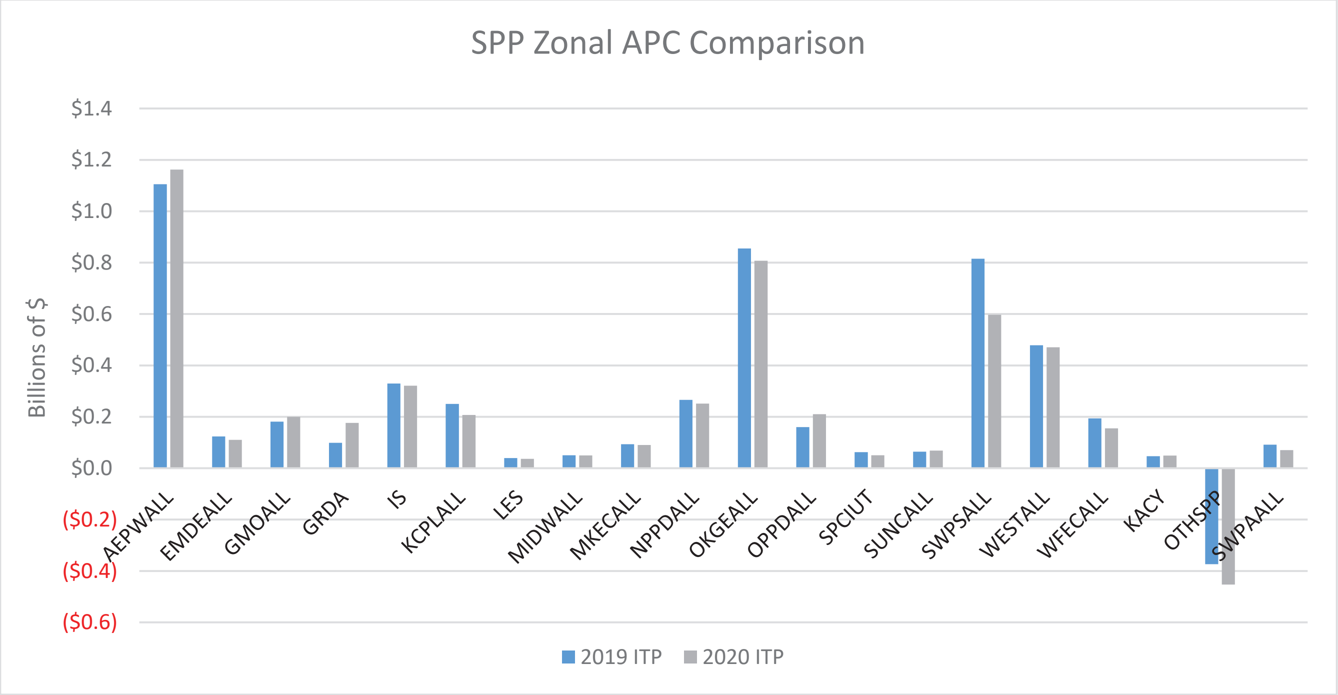


Figure 3.15: SPP Zonal APC Comparison[16]

---

[16] Any reference to the Integrated System (IS) legacy system is currently being assessed and is equivalent to the UMZ.

3.2.4 INTERCHANGE

The 2020 ITP model interchange was validated against the 2019 ITP and current SPP operations data. The 2020 ITP model is similar in shape and magnitude while overall exports are higher in the 2020 ITP than in the 2019 ITP.

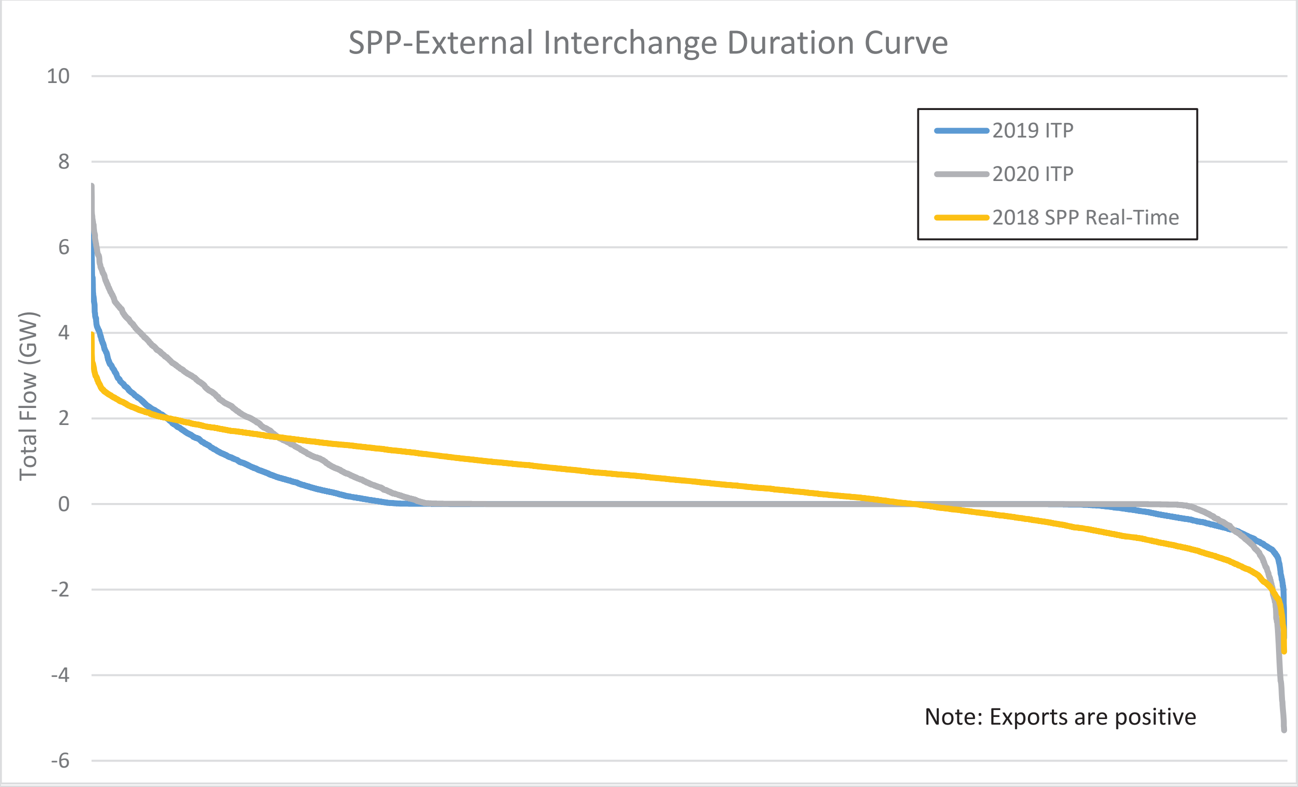


Figure 3.16: Interchange data comparison

4 NEEDS ASSESSMENT

SPP and its member organizations worked together to forecast and analyze the regional transmission system's economic, reliability, operational and public policy needs.

4.1 ECONOMIC NEEDS

SPP determines economic needs based on the congestion score associated with a constraint (monitored element/contingent element pair). The congestion score is calculated by multiplying the number of hours a constraint is congested in the model by the average shadow price of that constraint. Constraints with a calculated congestion score greater than 50k are considered an economic need. Additional constraints were identified that did not meet the 50k score, because they were related to the SPP-MISO Coordinated System Plan (CSP). The economic needs identified per future are shown in Figure 4.1 and Figure 4.2, and Table 4.1 and Table 4.2.

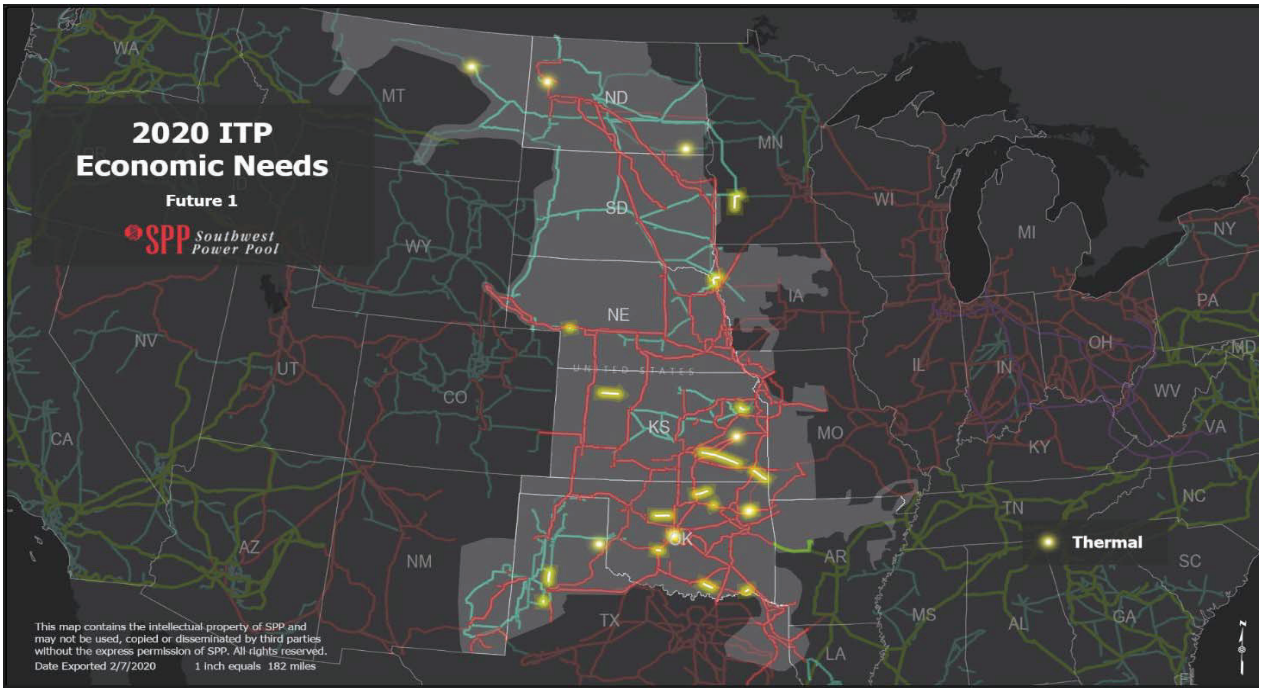


Figure 4.1: Future 1 Economic Needs

Constraint	2022 Congestion Score	2025 Congestion Score	2030 Congestion Score
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	471,640	742,822	1,104,558
Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	249,849	273,418	878,571
Watford 230/115 kV transformer circuit 1 for the loss of Watford 230/115 kV circuit 2	129,827	160,785	368,343
SPSNMTIES	258,996	139,555	499,965
Neosho-Riverton 161 kV for the loss of Blackberry-Jasper 345 kV	2,112	2,362	204,967
Russett-South Brown 138 kV for the loss of Caney Creek-Little City 138 kV	-	73	198,136
Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV	24,557	50,251	188,163
Shamrock 115/69 kV transformer for the loss of Sweetwater-Chisholm 230 kV	44,005	93,937	179,494
Tecumseh Hill-Stull 115 kV for the loss of Lawrence Hill-Swissvale 230 kV	-	770	161,808
Ogallala (NPPD)-Ogallala (Tri-State)115 kV for the loss of Ogallala-Grant 115 kV	48,838	73,245	113,456
Kress-Hale 115 kV for the loss of Swisher-Tuco 230 kV	78,368	79,027	100,584
Hoxie-Beach 115 kV for the loss of Mingo-Setab 345 kV	-	49,405	98,913
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	279,083	190,546	98,374
Fort Peck 230/115 kV transformer for the loss of Fort Peck-Dawson County 230 kV	75,115	81,231	95,612
Franks-South Crocker 161 kV for the loss of Huben-Franks 345 kV	15,925	5,743	89,487
Cimarron 345/138 kV transformer circuit 1 for the loss of Cimarron 345/138 kV transformer circuit 2	12,499	47,521	86,676
Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	64,087	67,792	74,697
Southwestern Station-Anadarko 138 kV for the loss of Anadarko-Gracemont 138 kV	417	17,625	57,225
Scottsbluff-Victory Hill 115 kV for the loss of Stegall-Stegall 230 kV	20,544	29,628	50,647

Constraint	2022 Congestion Score	2025 Congestion Score	2030 Congestion Score
GRDA 161/115 kV transformer circuit 2 for the loss of GRDA 345/161 kV transformer	10,033	19,668	50,109
Columbus East 230/115 kV transformer for the loss of Columbus East-Shell Creek 345 kV	2,288	34,138	49,182
Oahe-Sully Buttes 115 kV for the loss of Fort Thompson-Leland Olds 345 kV	-	35,036	48,119
Granite Falls-Marshall Tap 115 kV for the loss of Lyon Co. 345/115 kV transformer	24,845	29,070	47,526
Czech Hall-Cimarron 138 kV for the loss of Cimarron-Draper 345 kV	482	8,752	37,737
Sioux City-Twin Church 230 kV for the loss of Raun-Hoskins 345 kV	991	43,452	33,843
Kelly 161/115 kV for the loss of Kelly-Tecumseh Hill 161 kV	14,818	11,047	33,503
Skyline-Quail Creek 138 kV for the loss of Northwest-Arcadia	-	-	33,144
Warrensburg-Warrensburg Air Force Base 161 kV for the loss of Overton-Sibley 345 kV	9,803	9,806	29,644
MISO RDT	3,419	11,044	22,016
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	221,537	588,917	15,434
Webster-Wright 161 kV for the loss of Ledyard-Colby 345 kV	818	3,635	11,789
Kelly 161/115 kV for the loss of Tecumseh Hill 161/115 kV transformer	39	24	6,927
Fulton-Patmos 115 kV for the loss of Sarepta-Longwood 345 kV	10	383	5,752
Webster-Wright 161 kV for the loss of Grimes-Beaver Creek 345 kV	383	3,575	4,340
Raun-Tekamah 161 kV for the loss of Raun-S3451 345 kV	324	4,622	2,733
Split Rock 345/115 kV transformer circuit 10 for the loss of Split Rock 345/115 kV transformer circuit 11	81	620	2,712
Raun-S3451 115 kV for the loss of Grimes-Beaver Creek 345 kV	-	1,616	2,112
Fulton-Patmos 115 kV for the loss of Grimes-Crockett 345 kV	-	-	549

Constraint	2022 Congestion Score	2025 Congestion Score	2030 Congestion Score
Webster 161/115 kV transformer for the loss of Grimes-Beaver Creek 345 kV	-	26	324
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	71,873	125,031	-
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Nodway 161 kV	-	-	-
Fairbilt-Winn County 161 kV (Base Case)	-	-	-
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Creston 161 kV	-	-	-
Neosho-Riverton 161 kV for the loss of Blackberry-Blackberry North 345 kV	67,781	55,853	-
Blue River-Parkland 138 kV for the loss of Arbuckle-Arbuckle Blue River Tap 138 kV	-	-	-
Jameston-Valley 115 kV for the loss of Hankson-Wahpeton 230 kV	-	-	-
Maryville (AECI)-Maryville 161 kV for the loss of Gentry-Fairport 161 kV	-	-	-
Fairbilt-Winn County 161 kV for the loss of Huntley-Fairbilt 161 kV	-	-	-

Table 4.1: Future 1 Economic Needs

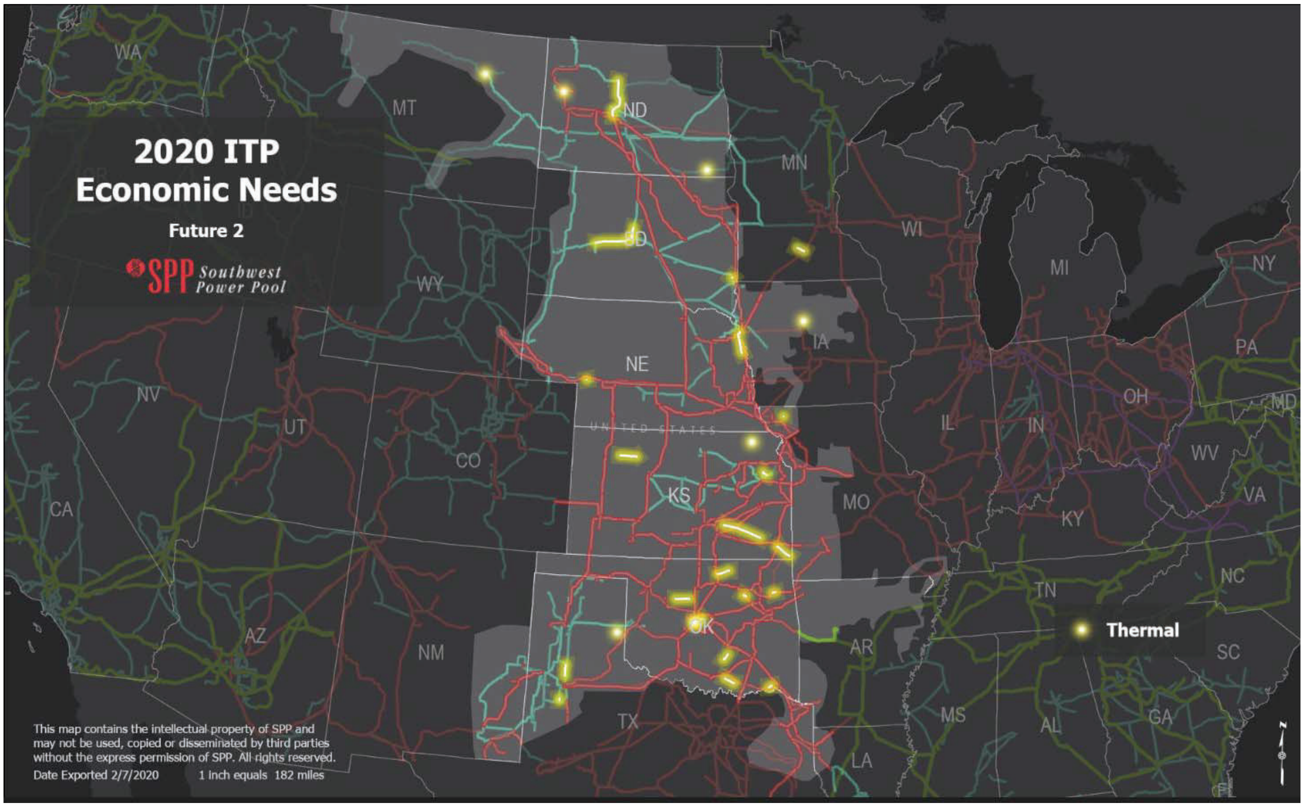


Figure 4.2: Future 2 Economic Needs

Constraint	2025 Congestion Score	2030 Congestion Score
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	1,037,096	985,274
Russett-South Brown 138 kV for the loss of Caney Creek-Little City 138 kV	224,826	522,446
Watford 230/115 kV transformer circuit 1 for the loss of Watford 230/115 kV circuit 2	188,501	356,741
SPSNMTIES	288,984	342,683
Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	161,396	330,812
Neosho-Riverton 161 kV for the loss of Blackberry-Jasper 345 kV	5,406	294,608
Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV	134,545	274,983
Maryville (AECI)-Maryville 161 kV for the loss of Gentry-Fairport 161 kV	50,470	264,789
Fairbilt-Winn County 161 kV for the loss of Huntley-Fairbilt 161 kV	132,080	248,553
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	292,945	165,336
Shamrock 115/69 kV transformer for the loss of Sweetwater-Chisholm 230 kV	101,372	163,207
Raun-Tekamah 161 kV for the loss of Raun-S3451 345 kV	54,763	159,429

Constraint	2025 Congestion Score	2030 Congestion Score
Kress-Hale 115 kV for the loss of Swisher-Tuco 230 kV	69,276	146,036
Cimarron 345/138 kV transformer circuit 1 for the loss of Cimarron 345/138 kV transformer circuit 2	44,947	127,108
Oahe-Sully Buttes 115 kV for the loss of Fort Thompson-Leland Olds 345 kV	47,974	122,616
Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	71,445	115,865
Split Rock 345/115 kV transformer circuit 10 for the loss of Split Rock 345/115 kV transformer circuit 11	21,941	104,407
Fort Peck 230/115 kV transformer for the loss of Fort Peck-Dawson County 230 kV	89,072	100,302
Czech Hall-Cimarron 138 kV for the loss of Cimarron-Draper 345 kV	20,066	91,094
Webster 161/115 kV transformer for the loss of Grimes-Beaver Creek 345 kV	64,431	87,329
Skyline-Quail Creek 138 kV for the loss of Northwest-Arcadia	181	86,046
Fairbilt-Winn County 161 kV (Base Case)	-	84,745
Tecumseh Hill-Stull 115 kV for the loss of Lawrence Hill-Swissvale 230 kV	8,535	80,935
Ogallala (NPPD)-Ogallala(Tri-State) 115 kV for the loss of Ogallala-Grant 115 kV	66,234	80,857
Hoxie-Beach 115 kV for the loss of Mingo-Setab 345 kV	35,723	76,020
Kelly 161/115 kV for the loss of Kelly-Tecumseh Hill 161 kV	39,759	73,301
Columbus East 230/115 kV transformer for the loss of Columbus East-Shell Creek 345 kV	41,254	71,847
MISO RDT	24,878	59,271
Blue River-Parkland 138 kV for the loss of Arbuckle-Arbuckle Blue River Tap 138 kV	-	58,860
Jameston-Valley 115 kV for the loss of Hankson-Wahpeton 230 kV	33,770	54,312
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Creston 161 kV	77,169	41,543
Franks-South Crocker 161 kV for the loss of Huben-Franks 345 kV	9,668	36,399
Scottsbluff-Victory Hill 115 kV for the loss of Stegall-Stegall 230 kV	17,080	34,387
Kelly 161/115 kV for the loss of Tecumseh Hill 161/115 kV transformer	227	25,582
Warrensburg-Warrensburg Air Force Base 161 kV for the loss of Overton-Sibley 345 kV	23,062	24,216
Webster-Wright 161 kV for the loss of Grimes-Beaver Creek 345 kV	13,979	20,086

Constraint	2025 Congestion Score	2030 Congestion Score
GRDA 161/115 kV transformer circuit 2 for the loss of GRDA 345/161 kV transformer	4,379	19,759
Southwestern Station-Anadarko 138 kV for the loss of Anadarko-Gracemont 138 kV	7,316	18,179
Granite Falls-Marshall Tap 115 kV for the loss of Lyon Co 345/115 kV transformer	17,005	17,400
Fulton-Patmos 115 kV for the loss of Sarepta-Longwood 345 kV	818	15,641
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	675,138	14,257
Sioux City-Twin Church 230 kV for the loss of Raun-Hoskins 345 kV	39,084	8,143
Webster-Wright 161 kV for the loss of Ledyard-Colby 345 kV	3,040	6,567
Fulton-Patmos 115 kV for the loss of Grimes-Crockett 345 kV	29	3,015
Raun-S3451 115 kV for the loss of Grimes-Beaver Creek 345 kV	6,005	2,192
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	162,158	-
Maryville (AECI)-Maryville 161 kV for the loss of Maryville-Nodway 161 kV	146,469	-
Neosho-Riverton 161 kV for the loss of Blackberry-Blackberry North 345 kV	73,449	-

Table 4.2: Future 2 Economic Needs

4.1.1 TARGET AREA

As part of the economic needs assessment, one target area was identified for the assessment to focus analysis efforts of SPP staff and stakeholders. After posting of the needs assessment, the need for additional analysis in another area of the system was identified by SPP staff. Drivers for these areas included:

- Unresolved transmission limits identified in previous ITP assessments
- Operational evaluation(s)
- Historical and projected congested flowgates in area
- Steady-state reliability violations
- Parallel and in-series relationships between flowgates/transmission corridors
- Impacted heavily by critical EHV contingencies
- Transient stability concerns for existing generators

4.1.1.1 MISO Regional Directional Transfer Target Area

The MISO Regional Directional Transfer (RDT) Target Area for the 2020 ITP aided SPP in regionally coordinated efforts to identify and evaluate potential transmission upgrades needed to mitigate impacts to the SPP transmission system due to transfers between the MISO Midwest and MISO South regions. SPP has historically seen congestion in the SPP footprint related to north-to-south flows within MISO. The flowgates that were identified as having the potential to meet these goals are shown in Figure 4.3 and listed in Table

4.3. SPP transmission facilities impacted by the exchange of power between MISO regions were evaluated as a target area with the potential for additional analysis in the 2020 ITP.

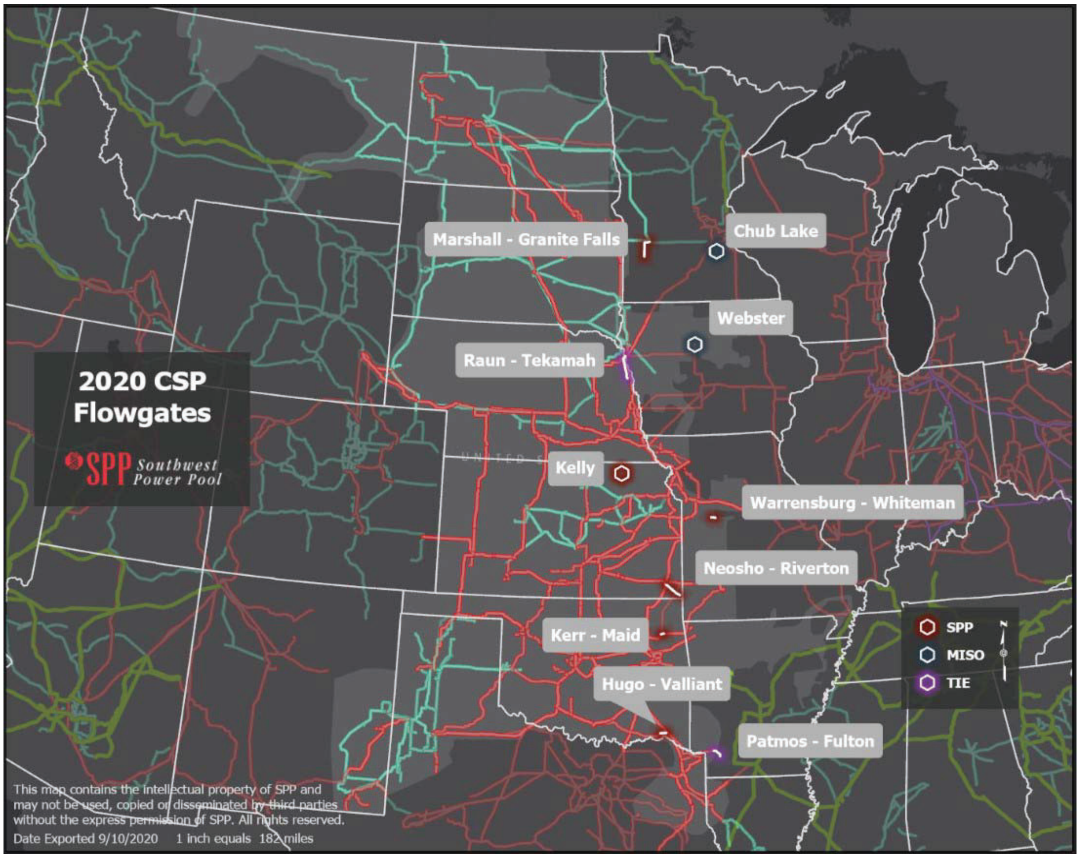


Figure 4.3: 2020 CSP Flowgates

CSP Target Flowgates
Raun-Tekamah 161 kV
Patmos-Fulton 115 kV
Chub Lake 345/115 kV transformer
Webster 345/115 kV transformer
Hugo-Valliant 138 kV
Kelly 161/115 kV transformer
Kerr-Maid 161 kV #2
Marshall-Granite Falls 115 kV
Neosho-Riverton 161 kV
Warrensburg-Whiteman AFB 161 kV

Table 4.3: MISO North CSP Interface Target Area Flowgates

4.1.2 SPS-NEW MEXICO TIES INTERFACE

The increased power flows into eastern New Mexico in SPS due to growing load and projected retirements has resulted in an increase in contingencies causing thermal and low voltage criteria and voltage collapse conditions in the initial and final base reliability and market power flow needs assessments. The SPS New Mexico Interface was added to the Market Economic Model post-constraint assessment to limit economic transfers and address voltage collapse observed in the development of the market economic model. This resulted in the SPSNMTIES interface being identified as a top congested economic need limiting economic transfer of energy into the area.

The interface limits imports into southeastern New Mexico in SPP market operations via the Crossroads-Eddy 345 kV, Yoakum-Hobbs 345 kV, San Juan-Chaves 230 kV, and Ink Basin-Hobbs 230 kV. The intent of the interface is maintain transmission system voltage stability in southeastern New Mexico under system intact and N-1 conditions. For the purposes of the assessment, the interface was limited (into southeastern New Mexico) to 765 MW for summer and winter seasons to proxy the power transfer limits that maintain pre- and post-contingent voltage limits on the transmission system in southeastern New Mexico and surrounding transmission system for both system intact and loss of critical generation and 230 kV and 345 kV lines. SPS has three interfaces in the area to proxy non-thermal system limits and limit power transfer limits listed in Table 4.4 The interface congestion was identified as being related to:

- Base reliability powerflow models low voltage and voltage collapse needs in year-10 summer peak
- Market powerflow models Future 1 low voltage needs and voltage collapse needs in year-10 summer peak
- Market powerflow models Future 2 low voltage needs and voltage collapse needs in year-five summer peak

Supplemental information was posted with the needs assessment explaining the SPSNMTIES interface and outlined solution evaluation and additional analysis needed to aid stakeholders with their solution submittals. The New Mexico Ties Interface Guidelines and Study Scope included a rigorous AC Power transfer thermal and voltage analysis and results with 0.02 per unit voltage safety margin applied to low voltage monitoring criteria. The study analysis and deliverables were required to support new SPSNMTIES interface ratings for economic solution evaluation.

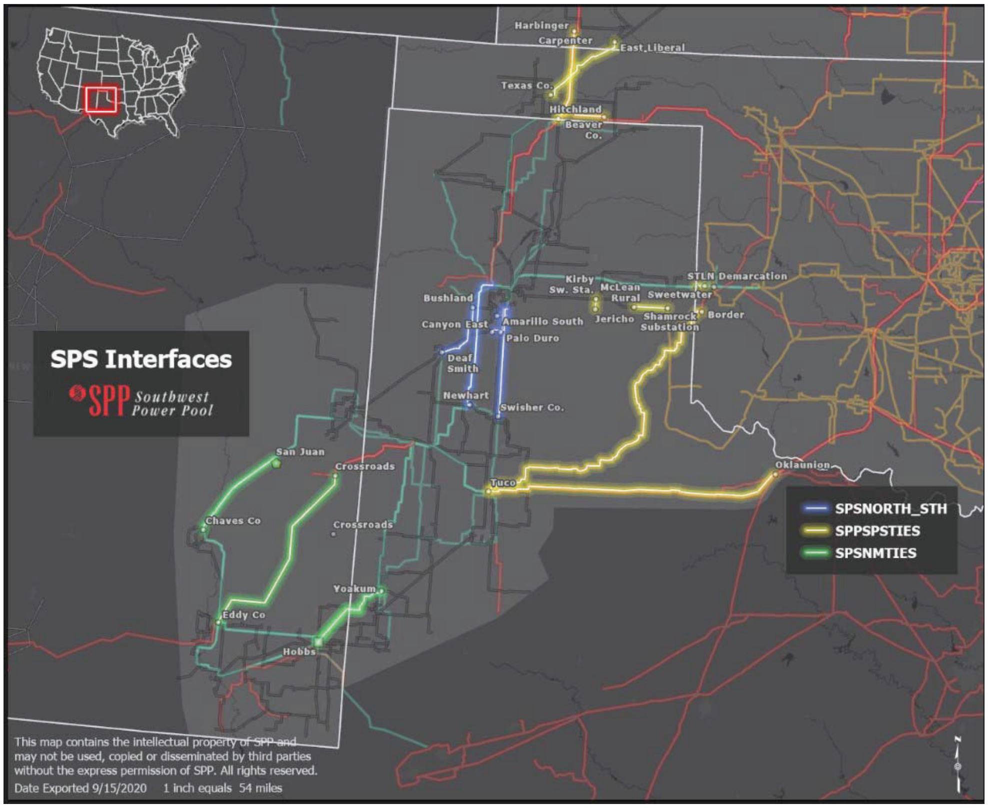


Figure 4.4: 2020 SPS New Mexico Ties Flowgates

Flowgate Interface		Limitation	
Name	**Definition**	**MW Flow**	**Directionality**
SPSNMTIES	San Juan Tap-Chaves County 230 kV	765	North-to-South
	Crossroads-Eddy County 345 kV		
	Ink Basin-Hobbs 230 kV		
	Yoakum-Hobbs 345 kV		
SPPSPSTIES	Border-Tuco 345 kV	1345	East-to-West
	Beaver County-Hitchland circuit 1&2 345 kV		
	Carpenter-Hitchland 345 kV		
	Jericho-Kirby 115 kV		
	E-Liberman-Texas Panhandle 115 kV		
	Oklaunion-Tuco 345 kV		
	Sham-McLean 115 kV		
	Sweetwater-Wheeler 230 kV		
SPSNORTH_STH	Amarillo South-Swisher 230 kV	1645	North-to-South
	Bushland-Deaf Smith 230 kV		
	Newhart-Potter County 230 kV		
	Randall-Canyon E Tap 115 kV		
	Randall-Palo Duro 115 kV		

Table 4.4: SPSNMTIES Interface Area Flowgates

4.2 RELIABILITY NEEDS

4.2.1 BASE RELIABILITY ASSESSMENT

Contingency analysis for the base reliability models consisted of analyzing P0, P1 and P2.1 planning events from Table 1 in the NERC TPL-001-4 standard, as well as remaining events that do not allow for non-consequential load loss or the interruption of firm transmission service.

During the needs assessment, potential violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, and identification of invalid contingencies, non-load-serving buses and facilities not under SPP's functional control. Figure 4.5 and Figure 4.6 summarize the number of remaining thermal and voltage needs[17] that were unable to be mitigated during the screening process.

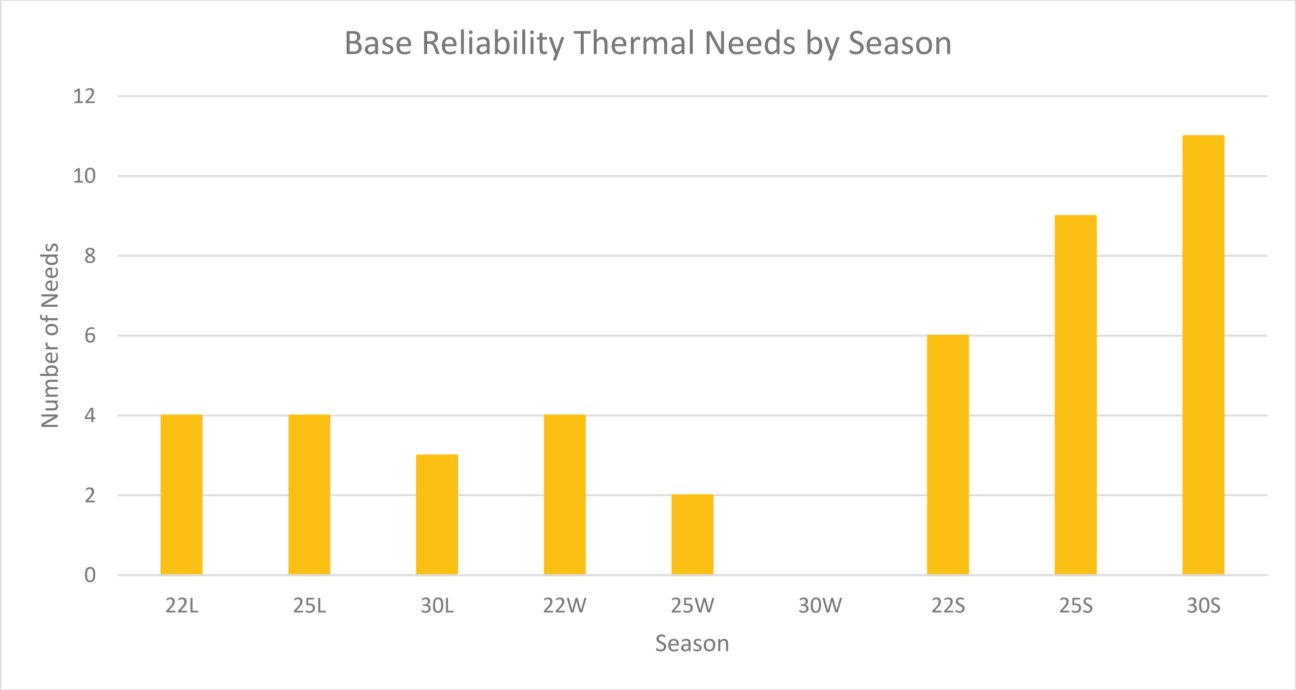
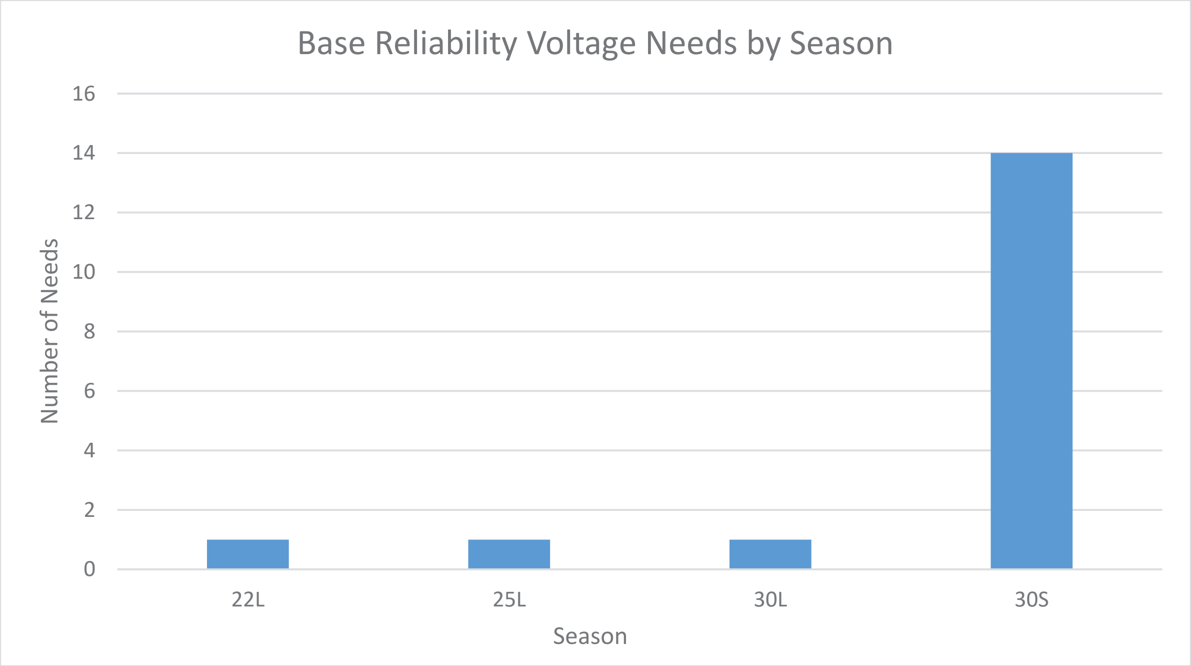


Figure 4.5: Unique Base Reliability Needs

---

[17] Figures summarize unique monitored elements.



22L	1
25L	1
30L	1
30S	14

Figure 4.6: Unique Base Reliability Voltage Needs

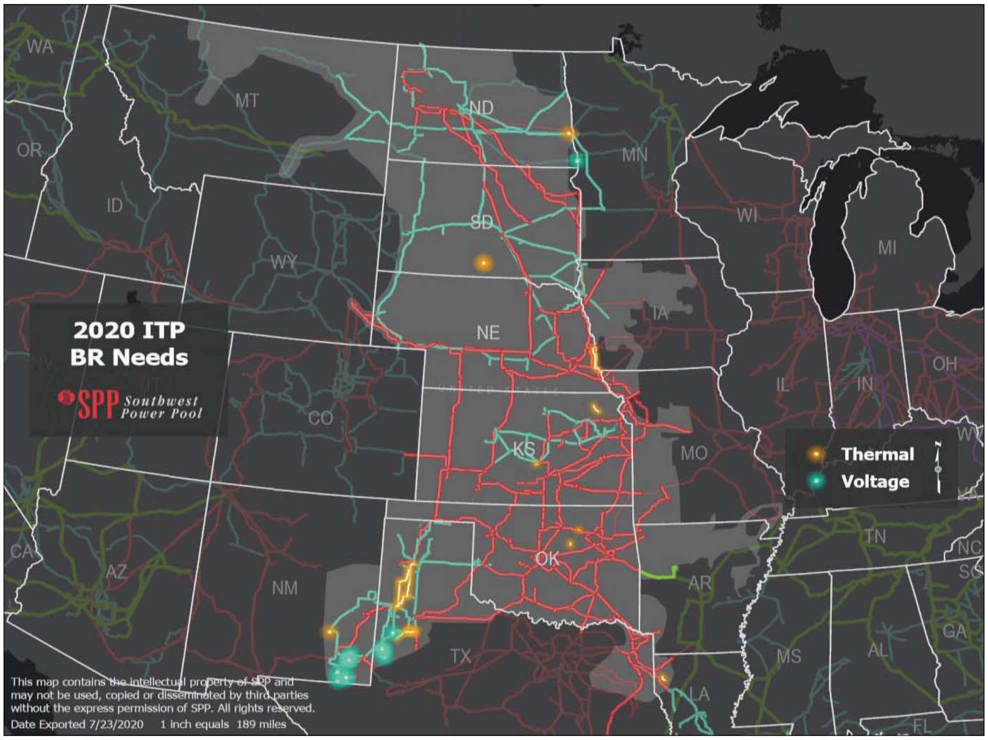


Figure 4.7: Base Reliability Needs

4.2.2 MARKET POWERFLOW ASSESSMENT

Contingency analysis for the market powerflow models was performed in accordance with the ITP Manual.

Figure 4.8 summarizes the number of remaining voltage needs[18] that were unable to be mitigated during the screening process. There were no thermal market powerflow model needs that were considered during the 2020 ITP.

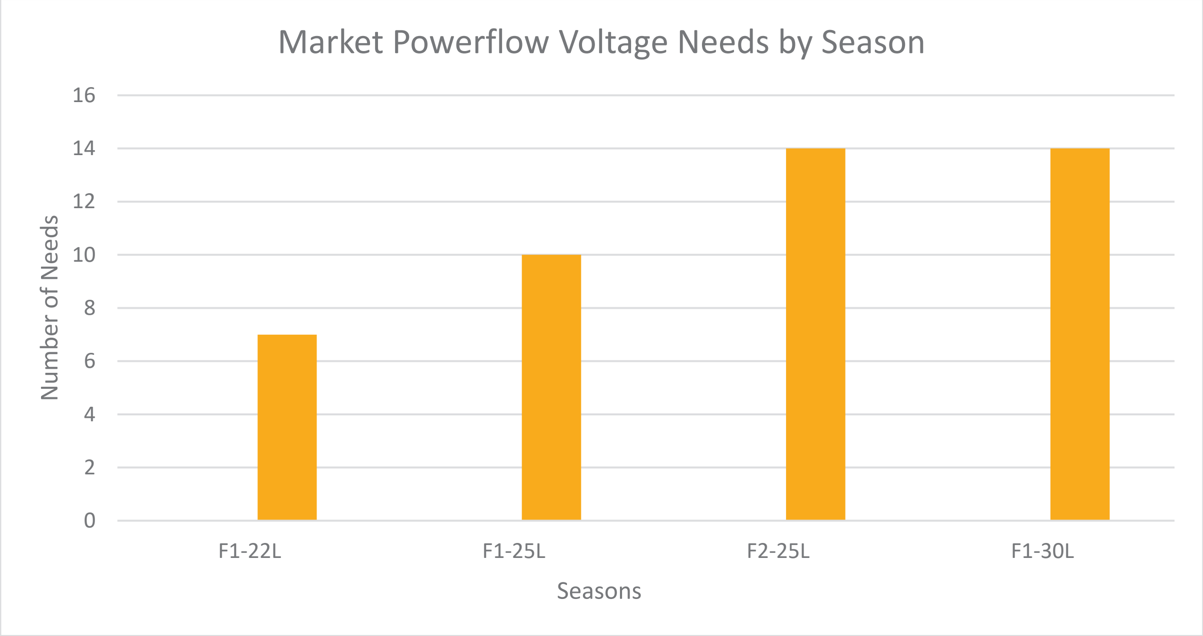
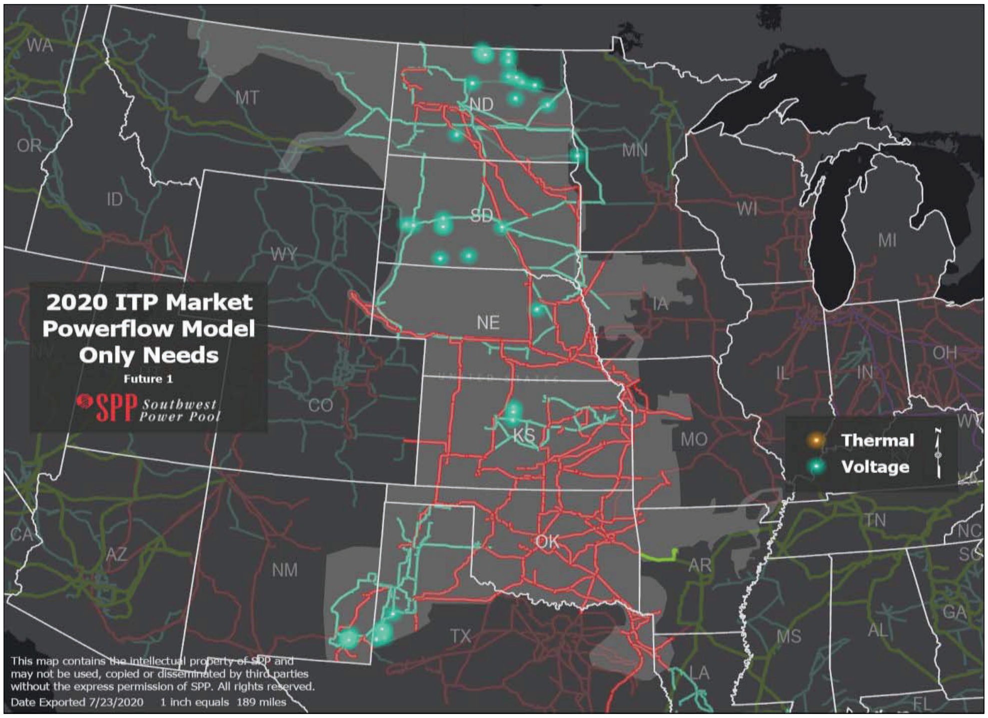


Figure 4.8: 2020 Market Powerflow Voltage Needs by Season



This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.
Date Exported 7/23/2020 1 inch equals 189 miles

Figure 4.9: Future 1 Reliability Needs

---

[18] The figure summarizes the unique monitored elements per season.

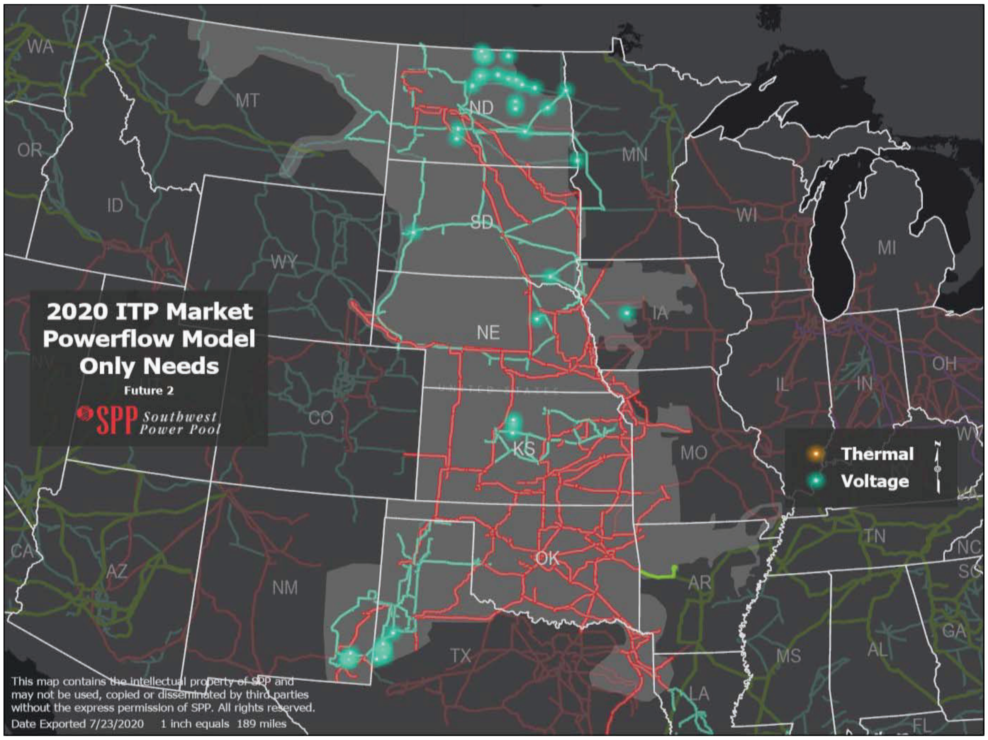


Figure 4.10: Future 2 Reliability Needs

4.2.3 NON-CONVERGED CONTINGENCIES

SPP used engineering judgment to resolve non-converged cases from the contingency analysis. Some non-converged cases could not be solved due to the contingency taken. Relative violations were identified as voltage collapse reliability needs in the applicable model and are listed in Table 4.5.

Model	Monitored Element	Contingent Element	Reliability Need
Base Reliability 2030 Summer Peak	Phantom 115 kV	Hobbs-Kiowa 345 kV	Voltage
Base Reliability 2030 Summer Peak	Phantom 115 kV	P53:345:SPS:EDDY-AT-FNC+	Voltage
Base Reliability 2030 Summer Peak	Phantom 115 kV	P42:345:SPS:KIOWA:J20####_SLG	Voltage
Future 2 2025 Summer Peak	Gaines 345 kV	Gaines Generator	Voltage
Future 1 2030 Summer Peak	Gaines 345 kV	Gaines Generator	Voltage
Future 2 2030 Summer Peak	Gaines 345 kV	Gaines Generator	Voltage

Table 4.5: Reliability Needs Resulting from Non-Converged Contingencies

4.2.4 SHORT-CIRCUIT ASSESSMENT

SPP provided the total bus fault current study results for single-line-to-ground (SLG) and three-phase faults to the Transmission Planners (TPs) for review.

The TPs were required to evaluate the results and indicate if any fault-interrupting equipment would have its duty ratings exceeded by the maximum available fault current. For equipment that would have its duty ratings exceeded, the TP provided the applicable duty rating of the equipment and the violation was identified as a short-circuit need.

The TPs can perform their own short-circuit analysis to meet the requirements of TPL-001. However, any corrective action plans that result in the recommended issuance of a NTC are based on the SPP short-circuit analysis.

The two TPs identifying short-circuit needs were Evergy and Western Farmers Electric Cooperative (WFEC). The needs are depicted in Figure 4.11.

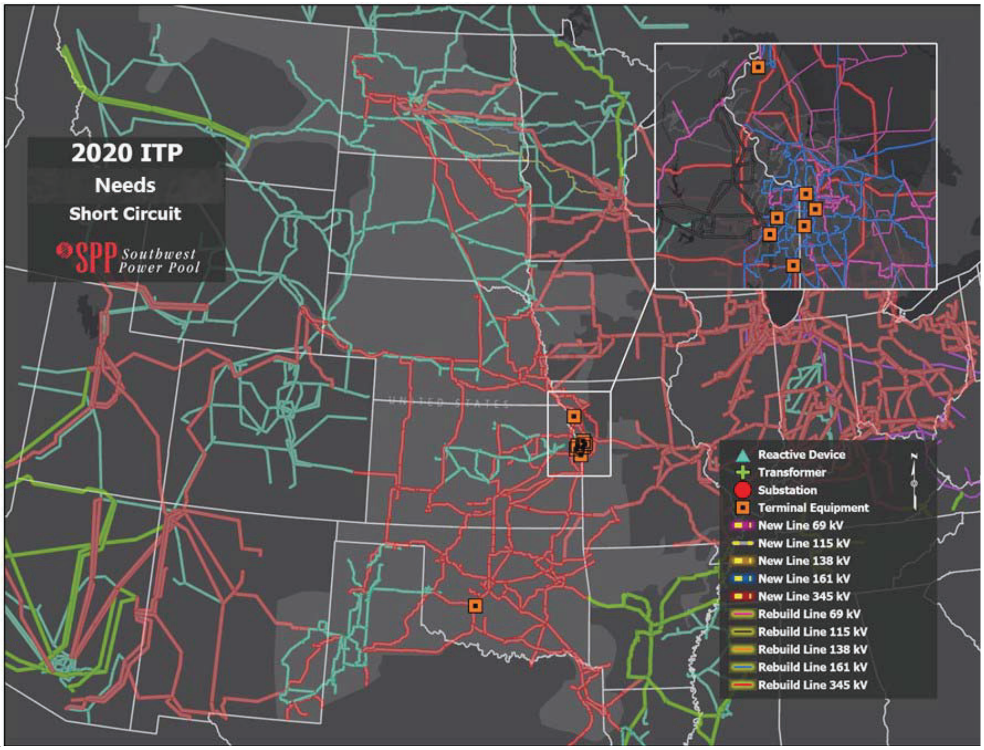


Figure 4.11: Short-Circuit Needs

4.3 PUBLIC POLICY NEEDS

Policy needs were analyzed based on the curtailment of renewable energy such that an energy-based renewable portfolio standard is not able to be met. Each zone with an energy mandate or goal was analyzed on a utility-by-state level for renewable curtailments to determine if they met their mandate or goal. Policy needs are the result of an inability to dispatch renewable generation due to congestion, and any utility-by-state not meeting its renewable mandate or goal.

All utilities met their overall renewable mandates and goals, thus no policy needs were identified.

4.4 PERSISTENT OPERATIONAL NEEDS

4.4.1 ECONOMIC OPERATIONAL NEEDS

The economic operational needs identified for the 2020 ITP assessment in Table 4.6 through Table 4.8 were posted for informational purposes only.

Constraint	Monitored Element	Contingent Element	Congestion Cost
TMP421_24095	XF Cimarron 345/138 kV	XF Cimarron 345/138 kV	$52,090,959
FRAMIDCANCED	LN Midwest-Franklin 138 kV	LN Cedar Lane-Canadian 138 kV	$42,896,115
CHAWATCHAPAT **TMP269_23661**	LN Charlie Creek-Watford 230 kV	LN Charlie Creek-Patent Gate 345 kV	$24,968,600
SMOSUMMULCIR	LN Smoky Hills-Summit 230 kV	LN Great Bend-Circle 230 kV	$21,897,392
SCOVICSTESTG **TMP127_23359**	LN Scottsbluff-Victory Hill 115 kV	XF Stegall 345/230 kV	$18,063,559
TMP159_24149	LN Russett-South Brown 138 kV	LN Little City-Brown Tap 138 kV	$11,522,032

Table 4.6: Economic Operational Needs

The constraints in Table 4.7 had associated future upgrades which are expected to reduce some or all congestion associated with the constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
TMP142_25323 **TMP39_23235**	LN Waverly-La Cygne 345 kV	LN Caney River-Neosho 345 kV	$80,306,731	2019 ITP approved Wolf Creek-Blackberry 345 kV
TMP270_23432	Cleveland 138 kV GRDA-AECI Bus Tie	LN Cleveland-Tulsa North 345 kV	$53,229,005	ITP approved Sooner-Wekiwa 345 kV

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
GGS	LN Gentleman-Red Willow 345 kV LN Gentleman-Sweetwater 345 kV circuit 1 LN Gentleman-Sweetwater 345 kV circuit 2 LN Gentleman-North Platte 230 kV circuit 1 LN Gentleman-North Platte 230 kV circuit 2 LN Gentleman-North Platte 230 kV circuit 3	System Intact	$34,002,078	NTC for Gentleman-Cherry Co.-Holt 345 kV (2012 ITP10)
TMP109_22593	LN Stonewall-Tupelo 138 kV	LN Seminole-Pittsburg 345 kV	$31,746,284	NTC for Tupelo 138 kV terminal upgrades (July 2021, 2017 ITP10)
NEORIVNEOBLC	LN Neosho-Riverton 161 kV	LN Neosho-Blackberry 345 kV	$18,063,262	Neosho-Riverton 161kV rebuild (October 2023, ATSS SPP-2019-AG1-AFS-2)
TMP226_24352	LN Mathewson-Northwest 345 kV	LN Mathewson-Cimarron 345 kV	$14,806,741	2019 ITP approved terminal upgrades
TEMP89_22229	LN Anadarko-Gracemont 138 kV	LN Washita-Southwestern 138 kV	$14,786,648	2019 ITP approved Anadarko-Gracemont 138 kV circuit 1 Rebuild
WICXF2WICXF1	XF Wichita 345/138 kV circuit 2	XF Wichita 345/138 kV circuit 1	$13,212,822	2014 ITP Near-Term, Viola-Sumner County 138 kV
TEMP72_22893	LN Wolf Creek-Waverly 345 kV	XF Wolf Creek 345/69 kV	$11,353,483	2019 ITP approved Wolf Creek-Blackberry 345 kV

Table 4.7: Economic Operational Needs

The constraints in Table 4.8 had associated upgrades in place which have reduced or eliminated loading of the associated constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
SUNAMOTOLYOA	LN Sundown-Amoco 230 kV	LN Tolk-Yoakum 230 kV	$28,915,221	Terminal equipment upgrades (2016 ITPNT), has not loaded since ratings update on 12/19/19
VINHAYPOSKNO	LN Vine Tap-North Hays 115 kV	LN Postrock-Knoll 230 kV	$15,194,807	Parallel Postrock-Knoll 230 kV (2017 ITP10), has not loaded since completion of project Q4 2018
TMP151_23193	LN Oakland North-Atlas Junction 161 kV	LN Asbury-Purcell 161 kV	$13,426,140	Upgrade (Non-Public)

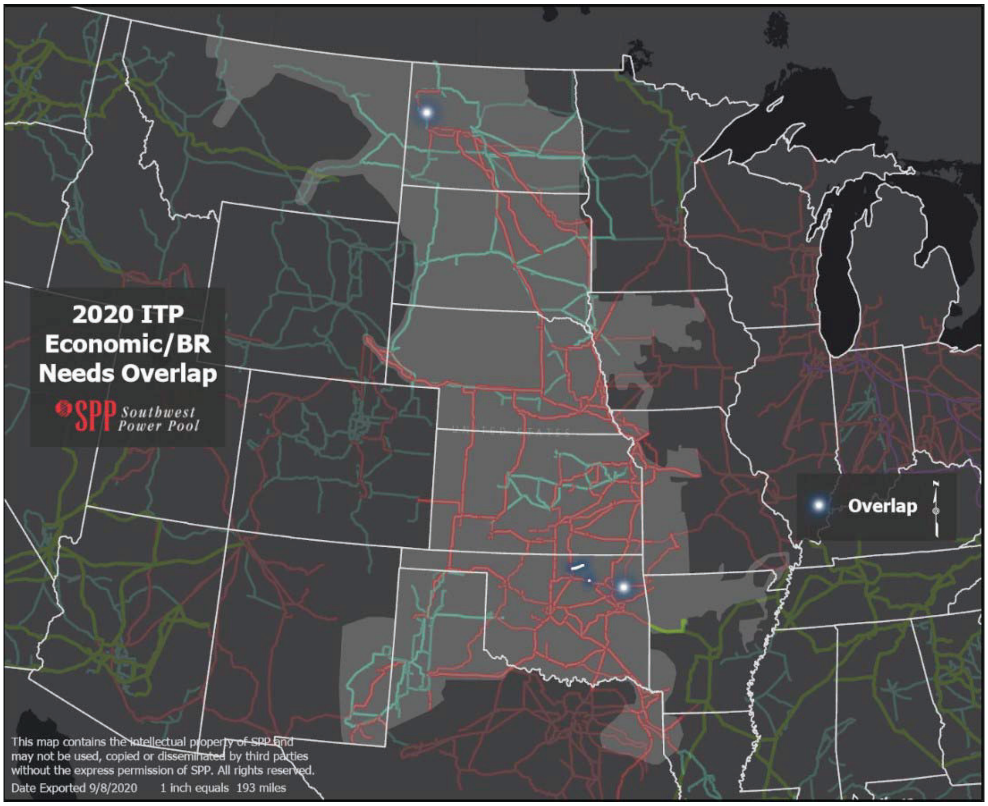
Table 4.8: Economic Operational Needs

4.4.2 RELIABILITY OPERATIONAL NEEDS

There were no reliability operational needs identified during the 2020 ITP assessment.

4.5 NEED OVERLAP

Relationships identified among the various need types aid in development of the most valuable regional solutions. SPP staff identified relationships among the economic needs to both the base reliability needs and informational economic operational needs.



This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.
Date Exported 9/8/2020 1 inch equals 193 miles

Figure 4.12: Base Reliability and Economic Need Overlap

Overlapping Reliability and Economic Needs
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV
Watford 230/115 kV transformer 1 for the loss of Watford 230/115 kV transformer 2
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV
GRDA 345/161 kV transformer 1 for the loss of GRDA 345/161 kV transformer 2

Table 4.9: Overlapping Reliability and Economic Needs

Overlapping Informational Operational and Economic Needs
Cimarron 345/138 kV transformer 1 for the loss of Cimarron 345/138 kV transformer 2
Scotts Bluff-Victory Hill 115 kV for the loss of Stegall 345/230 kV transformer
Russett-South Brown 138 kV for the loss of Little City-Brown Tap 138 kV
Neosho-Riverton 161 kV for the loss of Blackberry-Neosho 345 kV
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV

Table 4.10: Overlapping Informational Operational and Economic Needs

4.6 ADDITIONAL ASSESSMENTS

Additional assessments were performed to satisfy SPP tariff requirements involving parts of the transmission system that were not included in the approved model sets.

4.6.1 GRIDLIANCE HIGH PLAINS

GridLiance High Plains (GLHP) performed its local planning process assessment in 2019 and identified two new transmission upgrades required to meet local planning process needs. To satisfy its own NERC and tariff requirements, GLHP requested SPP to exercise the requirements under FAC-002 and Attachment O, Section II.1(e), of the tariff to perform a no-harm analysis on the proposed upgrades and coordinate the upgrades with the potential solutions of the 2020 ITP assessment.

An analysis was performed to satisfy these obligations by determining the impact of including the proposed local planning process upgrades in the 2020 ITP base reliability and market powerflow model sets. After performing the no-harm study on the projects, two overload violations were identified as resultant of one the GLHP local planning projects. GridLiance then identified discrepancies between SPP's models and their internal models which had higher MVA capacity on the violated lines. The project in question was resubmitted with additional rating corrections and no further violations were discovered. Therefore, no new transmission needs or violations were identified on the existing system due to the proposed local planning process upgrades.

Upgrades	Cost Est. (millions)	Location	Proposed ISD
Goodwell-Red Devil 115 kV line, Red Devil substation expansion, and Goodwell-Y-Road115 kV terminal equipment	16	Oklahoma Panhandle	2023
Winfield Tie 69 kV new substation,14.4 MVAR capacitor bank	8	Southern Kansas	2022

Table 4.11: Upgrades identified in GridLiance local planning assessment in 2019

5 SOLUTION DEVELOPMENT AND EVALUATION

Solutions were evaluated in each applicable scenario and modeled to determine their effectiveness in mitigating the needs identified in the needs assessment. The project solutions assessed included the Federal Energy Regulatory Commission (FERC) Order 1000 and Order 890 solutions submitted by stakeholders, SPP staff, projects submitted in previous planning studies, and model adjustments/ corrections. MISO staff also provided a subset of solutions identified in the MTEP20 for evaluation in SPP models. SPP staff analyzed 1,577 Detailed Project Proposals (DPP) solutions received from stakeholders and approximately 626 SPP staff solutions (including those provided by MISO as well as additional solutions developed during portfolio development). SPP staff members developed a standardized conceptual cost template to calculate a conceptual cost estimate for each project to utilize during screening.

5.1 RELIABILITY PROJECT SCREENING

Solutions were tested in each powerflow model to determine their ability to mitigate reliability criteria violations in the study horizon. To be considered effective, a solution must have been able to address the needs such that the identified facilities were within acceptable limits defined in the SPP Criteria and members' more stringent local planning criteria. Figure 5.1 illustrates the reliability project screening process.

Reliability metrics developed by SPP staff and stakeholders and approved by the TWG were calculated for each project and used as a tool to aid in developing a portfolio of projects to address all reliability needs. The first metric is cost per loading relief (CLR) score, which relates the amount of thermal loading relief a solution provides to its engineering and construction (E&C) cost. The second metric is cost per voltage relief (CVR) score, which relates the amount of voltage support a solution provides to its E&C cost.

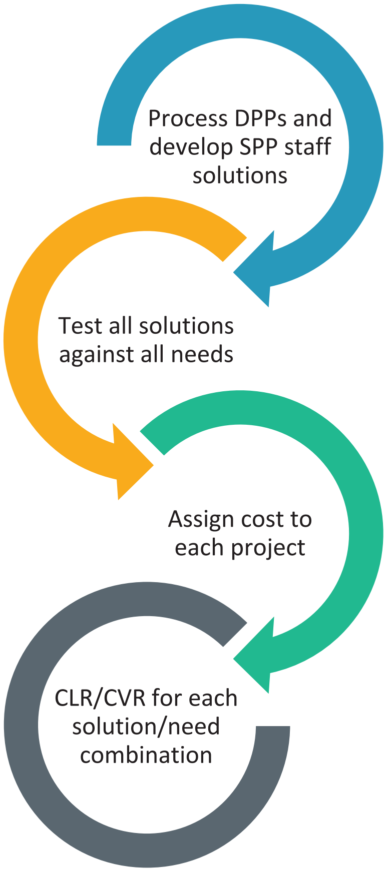


Figure 5.1: Reliability Screening Process

5.2 ECONOMIC PROJECT SCREENING

All solutions were evaluated for their economic performance to determine their effectiveness in mitigating transmission congestion in the study horizon. A one-year benefit-to-cost (B/C) ratio and a 40-year net present value (NPV) B/C ratio were calculated for each project based on its projected APC savings in each future and study year.

The annual change in APC for all SPP pricing zones is considered the one-year benefit to the SPP region for each study year. The one-year benefit is divided by the one-year cost of the project to develop a B/C ratio for each project. The one-year cost, or projected annual transmission revenue requirement (ATRR), is calculated using a historical SPP average net plant carrying charge (NPCC) multiplied by the project conceptual cost. The NPCC used for this assessment was 16.38 percent. The 40-year project cost is calculated using this NPCC, an eight percent discount rate and a 2.5 percent inflation rate.

The correlation of congestion in different areas of the system was identified and accounted for during the economic screening process. Where appropriate, this included adding new flowgates to screening simulations to ensure potential congestion created by projects would be captured, as well as pairing certain projects to ensure correlated congestion would be resolved by a more comprehensive solution set. These adjustments ensure the projected benefits of projects are not over- or under-stated.

5.3 SHORT-CIRCUIT PROJECT SCREENING

Solutions submitted to address overdutied breakers were reviewed to ensure the updated breaker ratings submitted were greater than the maximum available fault current identified in the short-circuit needs assessment.

5.4 PUBLIC POLICY PROJECT SCREENING

No public policy needs were identified in the 2020 ITP; therefore, no projects were analyzed during the public policy project screening.

5.5 PERSISTENT OPERATIONAL PROJECT SCREENING

In October 2019, the MOPC approved a waiver of the requirement to evaluate solutions against the economic operational needs associated with flowgates in the 2020 ITP assessment due to identified software limitations. Due to this approved waiver, no projects were analyzed during persistent operational project screening.

6 PORTFOLIO DEVELOPMENT

6.1 PORTFOLIO DEVELOPMENT PROCESS

Figure 6.1 shows a high-level overview of the portfolio development process. The process starts with the utilization of project metric results in project grouping and continues through the development of a consolidated portfolio that comprehensively addresses the system's needs.

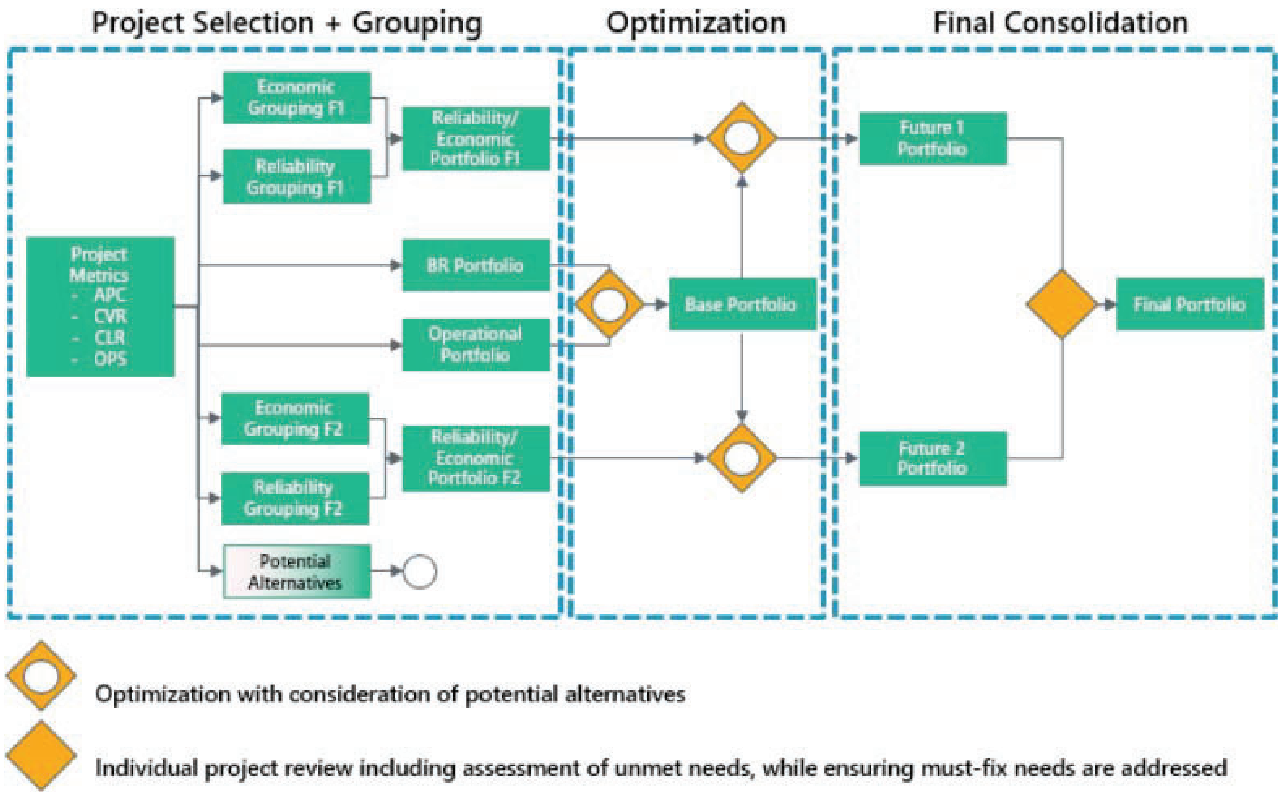


Figure 6.1: Portfolio Development Process

6.2 PROJECT SELECTION AND GROUPING

Once all solutions were screened, draft groupings were developed in parallel to address the different need types across the system. SPP used Study Estimates and stakeholder feedback from regularly-scheduled working group meetings, the July 2020 SPP transmission planning summit, and SPP's Request Management System.

6.2.1 STUDY ESTIMATES

Solutions that performed well using the screening assessments described in section 5, Solution Development and Evaluation were sent out for the development of Study Estimates (final project cost within ±30 percent). In cases where the cost estimate was not received before the July 2020 SPP transmission planning summit, conceptual cost estimates were utilized. Individual project upgrades with the potential to be deemed competitive were sent to a third-party cost estimator. Remaining project upgrades were sent to the incumbent transmission owner(s). Once the study estimates were received, that cost was used for the remainder of the portfolio development process.

6.2.2 RELIABILITY GROUPING

A programmatic method was used to compare the metric results for the extensive number of solutions to be evaluated. Using this solution selection software, a subset of solutions was generated by considering the metrics described in section 5.1. During this process, SPP staff applied engineering judgment to develop a draft list of selected and high-performing alternate solutions. This analysis was performed for each of the base reliability, Future 1, and Future 2 reliability needs.

The list of reliability solutions was continually refined through stakeholder feedback. Figure 6.2 below shows the final reliability grouping selected to address the valid list of reliability needs in the 2020 ITP.

Project	Area	Cost	Scenario[19]
Grady 138 kV capacitor bank	AEPW	$688,781	22S / BR
South Shreveport-Wallace Lake 138 kV rebuild	AEPW	$23,622,577	25S / BR
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	OKGE	$5,362,799	25S / BR
S3456-S3458 345 kV terminal equipment	OPPD	$678,865	30S / BR
Allen-Lubbock South 115 kV rebuild	SPS	$6,817,226	22S / BR
Allen-Quaker 115 kV rebuild	SPS	$4,732,267	22S / BR
Bushland-Deaf Smith 230 kV terminal equipment	SPS	$923,938	22L / BR
Carlisle-Murphy 115 kV rebuild	SPS	$4,746,175	22S / BR
Deaf Smith-Plant X 230 kV terminal equipment	SPS	$2,100,196	22L / BR
Deaf Smith #6-Friona 115 kV rebuild	SPS	$12,626,190	22L / BR
Deaf Smith #6-Hereford 115 kV rebuild	SPS	$6,660,556	22L / BR
Eddy County-North Loving 345 kV new line	SPS	$64,422,600	30S / BR
Jones-Lubbock South 230 kV terminal equipment circuit 1	SPS	$666,728	30S / BR
Jones-Lubbock South 230 kV terminal equipment circuit 2	SPS	$397,668	30S / BR
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	SPS	$872,391	22S / BR
Maljamar 115 kV capacitor bank	SPS	$685,440	30S / F1
Newhart-Plant X 230 kV terminal equipment	SPS	$2,024,293	22L / BR
Newhart-Potter County 230 kV terminal equipment	SPS	$731,282	22L / BR
Replace Roswell 115/69 kV transformer #1	SPS	$2,777,743	22S / BR

---

[19] This is the earliest season.

Project	Area	Cost	Scenario[19]
Russell 115 kV capacitor bank	SUNC	$2,841,951	22S / F1,F2
Nixa-Nixa Espy 69 kV terminal equipment	SWPA	$91,147	25S / BR
Agate 115 kV reactor	WAPA	$571,200	22L / F1,F2
Bismarck 115 kV reactors	WAPA	$2,380,700	22L / BR,F2
Devil's Lake 115 kV reactor	WAPA	$1,190,000	22L / F1,F2
Moorehead 230 kV reactor	WAPA	$1,515,440	22S / F1,F2
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	WAPA	$11,394,000	22L / BR
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	WAPA	$3,562,780	22L / BR
Circleville-Goff 115 kV circuit 1 rebuild	WERE	$12,114,772	25S / BR
Goff-Kelly 115 kV rebuild	WERE	$7,108,395	25S / BR
Meadowlark-Tower 33 115 kV rebuild	WERE	$1,342,588	30S / BR

Table 6.1: Reliability Project Grouping

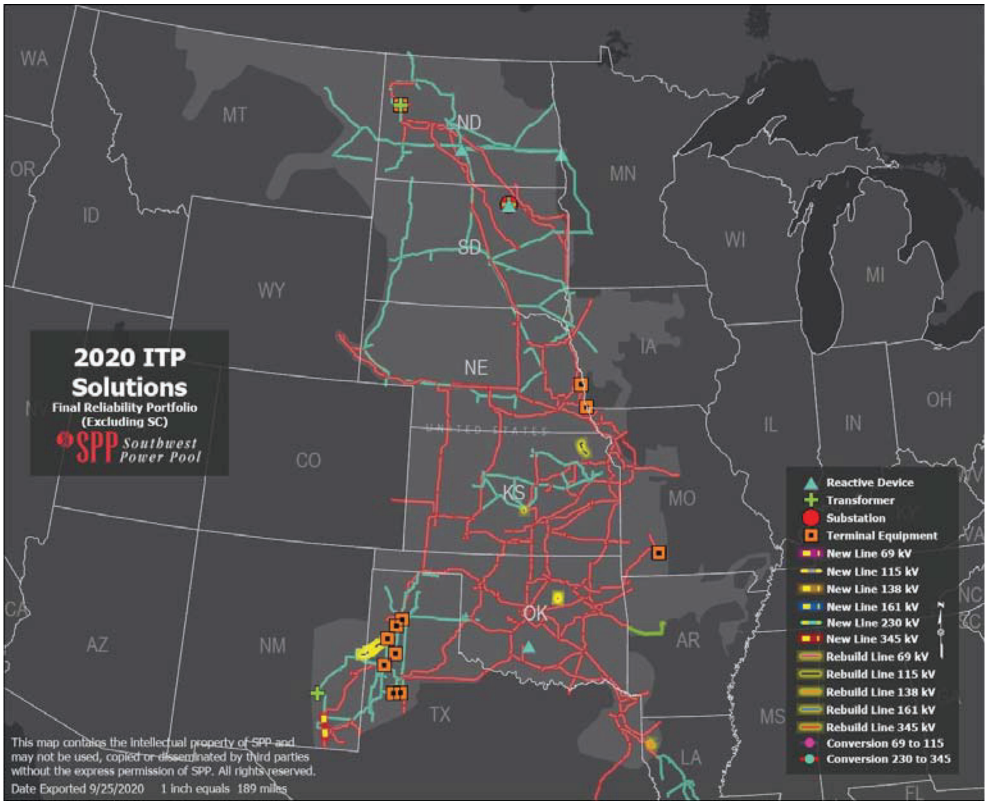


Figure 6.2: Reliability Project Grouping

6.2.3 SHORT-CIRCUIT GROUPING

The solutions submitted to address overdutied breakers identified in the short-circuit needs assessment were grouped together as a set of solutions to address the short-circuit needs. No testing was required for these solutions because the submitted breaker upgrades only need to be rated higher than the maximum fault current identified in the needs assessment. Table 6.2 summarizes the final short-circuit grouping, while Figure 6.3 shows the approximate location of identified projects within the SPP footprint.

Reliability Project	Area	Cost	Scenario
Replace three breakers at Northeast 161 kV	KCPL	$887,479	22S / BR
Replace one breaker at Stilwell 161 kV	KCPL	$566,485	22S / BR
Replace one breaker at Leeds 161 kV	KCPL	$566,485	22S / BR
Replace one breaker at Shawnee Mission 161 kV	KCPL	$566,485	22S / BR
Replace one breaker at Southtown 161 kV	KCPL	$566,485	22S / BR
Replace two breakers at Lake Road 161 kV	KCPL	$1,132,970	22S / BR
Replace two breakers at Craig 161 kV	KCPL	$1,132,970	22S / BR
Replace four breakers at Anadarko 138 kV	WFEC	$850,000	22S / BR

Table 6.2: Short-Circuit Project Grouping

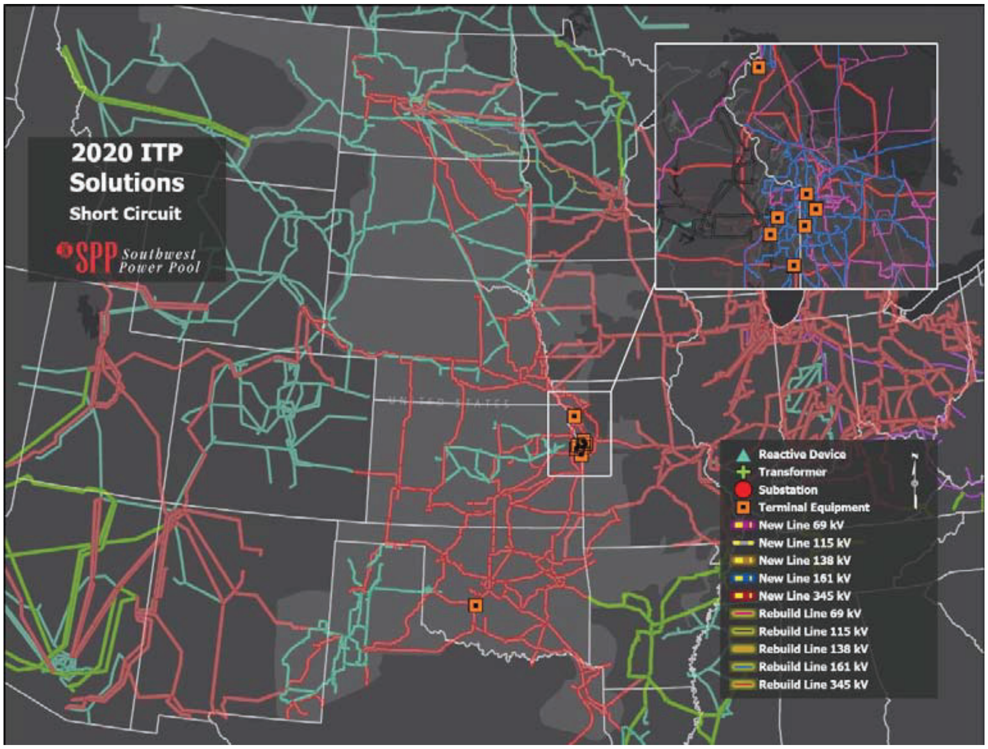


Figure 6.3: Short-Circuit Project Grouping

6.2.4 ECONOMIC GROUPING

All projects with a one-year B/C ratio of at least 0.5 or a 40-year NPV B/C ratio of at least 1.0 during the project screening phase were further evaluated while developing project groupings. Projects were evaluated and grouped based on one-year project cost, one-year APC benefit, 40-year project cost, 40-year NPV B/C ratio, and congestion relief for the economic needs.

Three economic project groupings were developed for each future, resulting in six total groupings:

1. Cost-Effective (CE): Projects with the lowest cost per congestion cost relief for a single economic need
2. Highest Net APC Benefit (HN): Projects with the highest APC benefit minus project cost, with consideration of overlap if multiple projects mitigate congestion on the same economic needs
3. Multi-variable (MV): Projects selected using data from the two other groupings; including the flexibility to use additional considerations

The following factors were considered when developing and analyzing project groupings per future:

- One-year project cost, APC benefit, and B/C ratio
- 40-year NPV cost, APC benefit, and the B/C ratio
- Congestion relief a project provides for the economic needs of that future and year
- Project overlap, or when two or more projects that relieve the same congestion are in a single portfolio
- Potential for a project to mitigate multiple economic needs
- Any potential routing or environmental concerns with projects
- Any long-term concerns about the viability of projects
- Seams and non-seams project overlap
- Relief of downstream and/or upstream issues, tested by event file modification
- Potential for a project to mitigate reliability, operational or public policy needs, which covers current market congestion
- Potential for a project to address non-thermal issues
- Need for new infrastructure versus leveraging existing infrastructure
- Larger-scale solutions that provide more robustness and additional qualitative benefits

Table 6.3 identifies a comprehensive list of economic projects included in the four initial groupings. Some projects appeared in multiple groupings.

	F1		F2	
Project Description	**CE**	**HN**	**CE**	**HN**
Fort Peck 230/115 kV transformer replacement	X	X	X	X
Watford 230/115 kV transformer circuit 1 terminal equipment and circuit 2 replacement	X	X	X	X
Lyon 345/115 kV transformer replacement	X	X	X	X
Blue River-Parklane 138 kV terminal equipment	-	-	X	X
Russett-South Brown 138 kV rebuild	X	X	X	X
Kelly 161/115 kV terminal equipment	X	X	X	X
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	X	X	X	X

	F1		F2	
Project Description	CE	HN	CE	HN
Airport 115/69 kV substation and transformer, Airport-Sioux City 115 kV new line	-	-	X	X
Anadarko-Southwest Station 138 kV terminal equipment	X	X	-	-
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	X	X	-	-
Ogallala-Ogallala 115 kV terminal equipment	X	X	X	X
Hugo-Valliant 138 kV terminal equipment	X	X	X	X
Atwood-Colby 115 kV terminal equipment, Hoxie-Beach-Redline 115 kV terminal equipment	X	X	-	-
Columbus East 230/115 kV transformer replacement	X	X	X	X
Sioux City-Twin Church 230 kV terminal equipment	X	X	-	-
Franks-South Crocker-Lebanon 161 kV terminal equipment	X	X	X	X
Pleasant Valley 345/138 kV station, Pleasant Valley-Minco 345 kV new line	-	X	-	X
Cimarron South 345/138 kV station, Cimarron South-Minco 345 kV new line, Quail Creek-Skyline 138 kV rebuild, re-terminate nearby 345 and 138 kV lines into new station	X	-	X	-
Oahe-Sully Buttes-Whitlock-Glenham 230 kV terminal equipment	X	X	X	X
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal upgrades	X	X	X	X
Victory Hill-Scottsbluff 115 kV and Alliance-Snake Creek 115 kV rebuild	X	-	-	-
Second Stegall 345/230 kV transformer, Stegall-Stegall 230 kV new line, Alliance-Snake Creek 115 kV rebuild	-	X	-	-
Tecumseh Hill-Stull-Mockingbird 115 kV rebuild	X	X	X	X

Table 6.3: Economic Project Grouping

6.2.4.1 Project Subtraction Evaluation

Draft groupings were developed using project screening results, which tests projects by incrementally adding changes to the base market economic models. When assessing a group of economic solutions, it is necessary to re-evaluate project performance within the grouping to ensure the projected APC benefit of each project in the grouping remains supportive of the required B/C ratio thresholds. "Subtraction evaluation" is used to identify when multiple projects can provide congestion relief to a constraint or projects that are dependent on each other to relieve overall system congestion. New sets of "base cases" were created by adding the solutions included in each grouping along with relevant model adjustments, corrections, and market powerflow model projects required to meet the future's needs. All economic projects were then removed from the models individually to determine each project's APC impact compared to the new base case. Projects that did not meet a 1.0 B/C ratio from the subtraction evaluation were removed from the grouping. This subtraction evaluation was repeated for each grouping until all remaining projects maintained a minimum B/C ratio of 1.0 over 40 years.

6.2.4.2 Final Economic Groupings

The selected grouping for each future was the grouping that provided the highest net benefit to the SPP region when comparing APC savings to the cost of the projects. The cost-effective grouping was selected for Future 1, while the highest net grouping was selected for Future 2. Table 6.4 shows the final list of projects included in each grouping.

Description	F1		F2	
	CE	HN	CE	HN
Arbuckle-Blue River 138 kV terminal equipment	-	-	X	-
Fort Peck 230/115 kV transformer replacement	-	X	-	-
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	X	X	X	X
Blue River-Parklane 138 kV terminal equipment	-	-	X	-
Anadarko-Gracemont 138 kV rebuild as double-circuit	X	X	X	-
Russett-South Brown 138 kV rebuild	X	X	X	X
Kelly 161/115 kV terminal equipment	-	-	X	-
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	X	X	X	X
GRDA 1 345/161 kV circuit 1 & circuit 2 terminal equipment	X	X	X	-
Hugo-Valliant 138 kV terminal equipment	-	-	X	-
Columbus East 230/115 kV transformer replacement	-	X	X	-
Split Rock 345/115 kV circuit 10 and 11 terminal equipment	-	-	X	X
Franks-South Crocker-Lebanon 161 kV terminal equipment	X	X	-	-
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	X	X	-	X
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	-	-	-	X
Oahe-Sully Buttes-Whitlock-Glenham-Campbell 230 kV terminal equipment	-	X	X	-
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal upgrades	X	X	X	X
Cimarron 345/138 kV circuit 3 Transformer, Cimarron-Czech Hall 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment	X	-	X	-
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	-	X	-	X
Anadarko-Gracemont 138 kV rebuild; Anadarko-Southwest Station 138 kV terminal equipment	-	-	-	X

Table 6.4: Final Economic Project Grouping

Figure 6.4 and Figure 6.5 show the approximate location of identified projects within the SPP footprint.

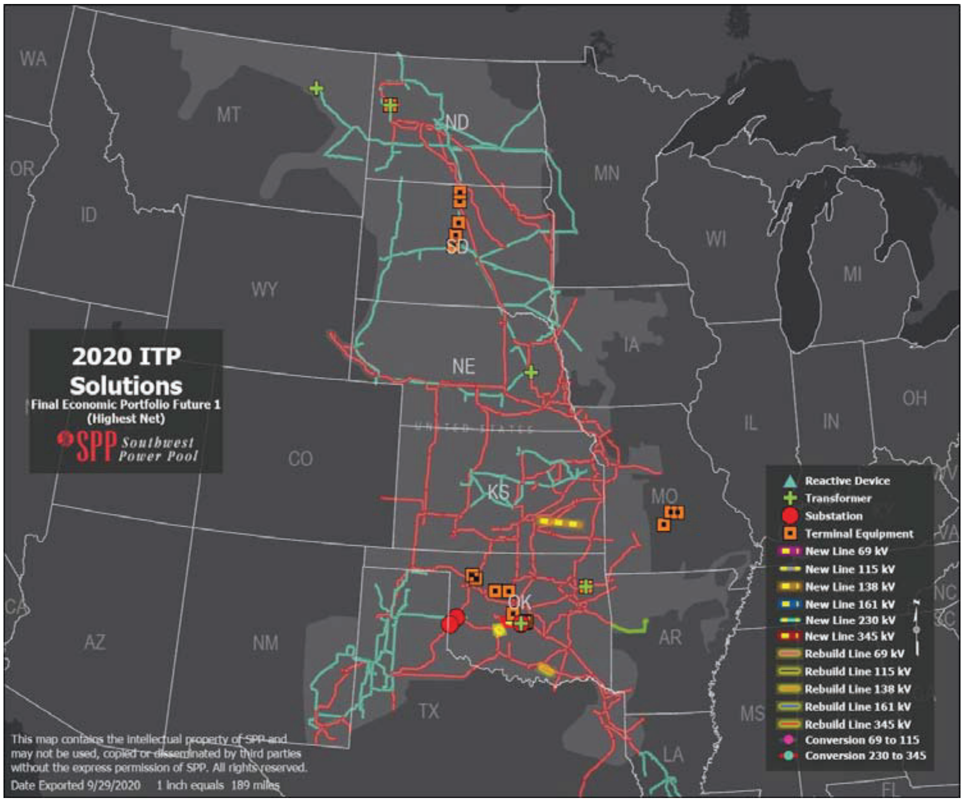


Figure 6.4: Final Project Groupings-Future 1-Highest Net

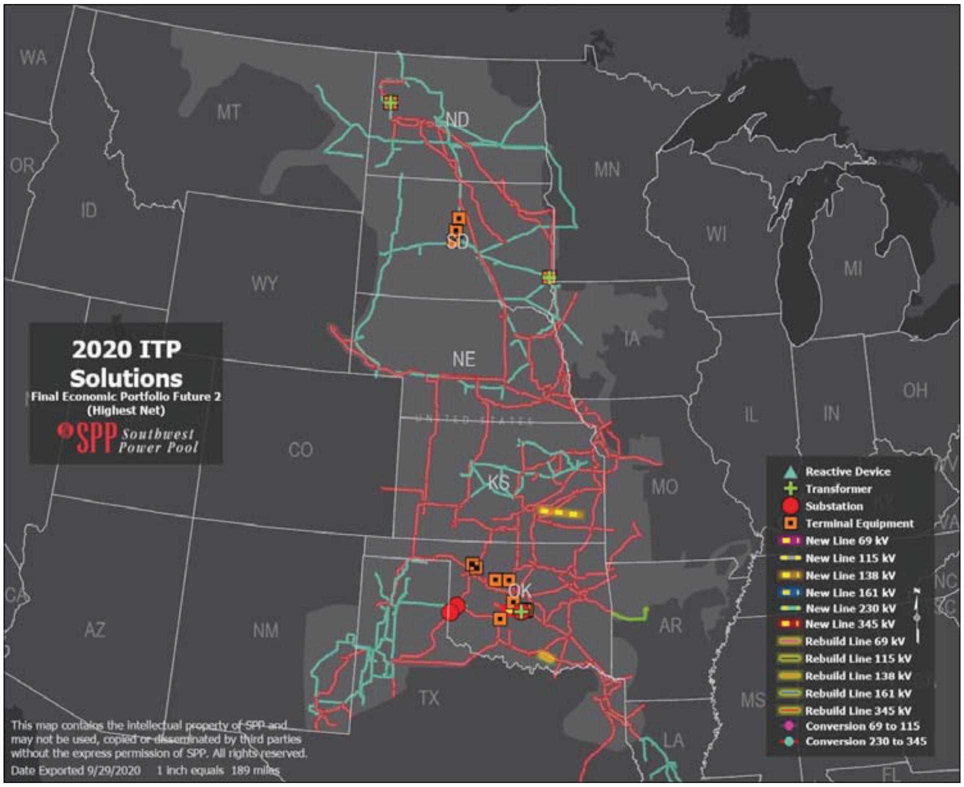


Figure 6.5: Final Groupings-Future 2-Highest Net APC

Table 6.5 shows a summary of benefits, costs, net APC benefit, and B/C ratios. Based on the net APC benefits detailed below, the grouping with the highest net APC benefit in each future was selected as the future's final portfolio.

Grouping	Y5 Benefit ($M)	Y10 Benefit ($M)	40-Year Benefit ($M)	40-Year NPV Cost ($M)	40-Year Net Benefit ($M)	Y5 B/C	Y10 B/C	40-Year B/C	Selected Portfolio
F1 CE	$55.7	$82.6	$1,528	$352.3	$1,176	1.50	2.22	4.34	
F1 HN	$63.4	$97.8	$1,821	$514.7	$1,306	1.17	1.80	3.54	X
F2 CE	$60.7	$106.2	$2,012	$316.1	$1,696	1.82	3.19	6.36	
F2 HN	$83.5	$131.8	$2,462	$474.3	$1,987	1.67	2.64	5.19	X

Table 6.5: Final Groupings-Benefit Cost, Net Benefits, and B/C Ratios

Figure 6.6 shows a 40-year B/C comparison of all the final groupings.[20]

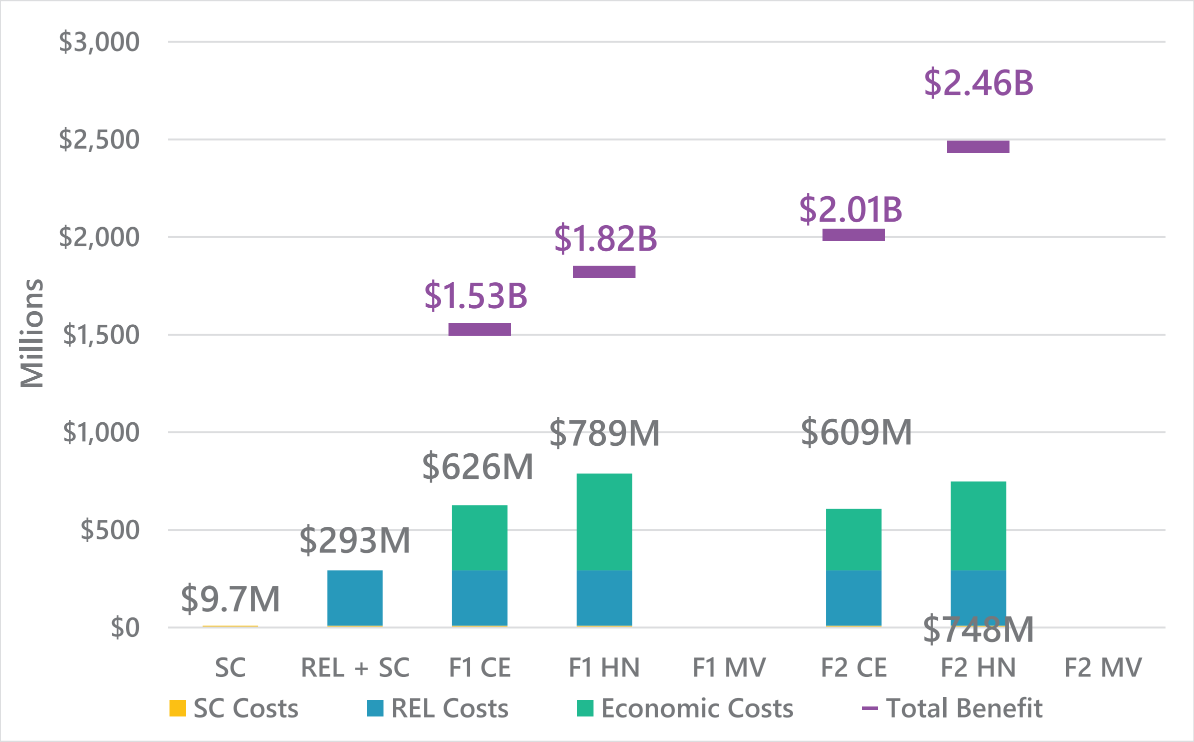


Figure 6.6: Final Groupings-Benefits and Costs Comparison

6.2.5 MISO RDT TARGET AREA

In order to mitigate impacts to the SPP transmission system due to transfers between the MISO Midwest and MISO South regions, a number of projects were considered. The flowgate that showed the greatest potential benefit to both MISO and SPP was the Raun-Tekamah 161 kV. Three of the foremost projects

---

[20] The 40-year costs represented in this figure are based upon the final net plant carrying charge.

during the analysis period were a new Raun-Council Bluffs 345 kV line, a new Raun-S3452 345 kV line, and a new Raun-S3451 345 kV line. These projects would create a strong corridor to alleviate constraints on the Raun-Tekamah flowgate. Figure 6.7 shows the approximate locations of identified projects.

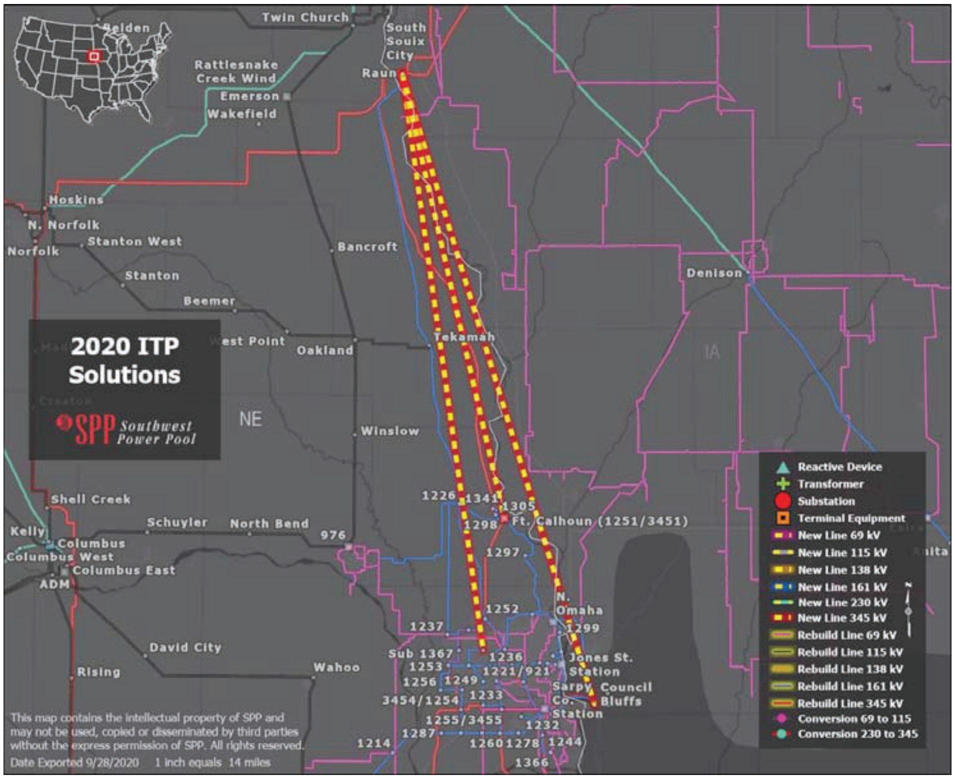


Figure 6.7: Potential SPP-MISO CSP Solutions

For a summary of SPP project cost, MISO and SPP benefits, and interregional cost sharing, see the information presented at the September 25, 2020 MISO-SPP IPSAC net conference.[21]

Due to differing methodologies between MISO and SPP when calculating benefits and project costs, the two RTOs decided not to pursue any projects in this area as part of the 2020 ITP. SPP is further investigating the differences in cost estimation, but did not have the time remaining in the schedule to address these differences in the 2020 ITP. These projects will continue to be investigated in future studies.

6.2.6 SPS-NEW MEXICO TIES INTERFACE

It was understood by SPP staff and communicated to stakeholders that the SPSNMTIES Interface would require a comprehensive solution to increase import capability into eastern New Mexico and sufficiently address system low voltage and voltage stability limits to support increased transfers of economic energy. Additional portfolio development considerations should also be given to the significant 702 MW combined

---

[21] CSP results for Raun-Council Bluffs and Raun-S3451 were presented at 09/25/2020 MISO-SPP IPSAC Net Conference (https://www.spp.org/Documents/63046/SPP-MISO%20IPSAC%20Meeting%20Materials%2020200925.zip)

cycle conventional resource plan unit and associated generator outlet facility[22] assumed in the eastern New Mexico area.

The transmission solutions screened included numerous combinations of existing reactive setting and configuration adjustments, new static and dynamic reactive devices, and additional HV and EHV facilities extending beyond the Eastern New Mexico area. Reliability project screening on AC power transfer models, results from the New Mexico Ties Interface Guidelines, and the study scope were used to identify top ranked solutions needing further review. Preliminary ranking results produced high-cost projects ranging from greater than $100 million to greater than $700 million to address system criteria violations for seven incremental transfer levels tested and resulting new interface ratings. Before further review of these preliminary results and additional solution evaluation, a relaxation run was performed on the SPSNMTIES interface by removing the constraint to determine potential APC Savings benefit and potential minimum project cost that would result in a 40-year NPV B/C ratio of at least 1.0.

	Y5 Benefit ($M)	Y10 Benefit ($M)	40-Year Benefit ($M)	40-Year B/C	Project Cost ($M)
F1	$57.6	$82.7	$1,317	1.00	$749.0
F2	$188.0	$120.9	$1,481	1.00	$842.7

Table 6.6: Potential APC Savings Benefit and Project Cost ($2025 Dollars)

The potential APC savings indicated that the high cost projects identified in the preliminary ranking results may prove to be economically justified and support further solution evaluation efforts. However, given ITP schedule, resource constraints and the complex nature of the solution evaluation needed by SPP staff and stakeholders to address the interface congestion, it was determined to delay any action on the congested interface to future ITP cycles and focus efforts on resolving the base reliability and market powerflow model reliability needs in eastern New Mexico.

Ultimately, no firm project selection was made for the economic issues.

6.3 OPTIMIZATION

The projects included in the reliability groupings were selected based on their ability to be cost-effective, maintain reliability, and meet the system's compliance needs. The economic projects were selected for their ability to provide ratepayer benefits from lower-cost energy by mitigating system congestion and improving markets for both buyers and sellers. The project groupings discussed previously were developed based on criteria specific to their need and model type. Reliability groupings specific to each future were evaluated to determine their impact on each economic grouping. Once those comprehensive future specific portfolios were developed, the impact of the base reliability portfolio was assessed.

---

[22] The generator outlet facility identified for the 702 MW combined cycle conventional resource plan unit sited at the Sidewinder site can be found in Table 2.4. Both resource plan unit and generator outlet facility have load serving and economic energy delivery qualities and would be part of a comprehensive solution unless a transmission only solution proved overwhelmingly cost-beneficial without the combined cycle conventional resource plan unit assumed in the Eastern New Mexico Area.

One project, the upgrades of both Watford 230/115 kV transformers, was identified in both the reliability and economic portfolios. Additional economic project subtraction analysis performed to determine the impact of the base reliability portfolio identified the removal of the Fort Peck 230/115 kV transformer replacement from the Future 1 portfolio. No impact to the reliability portfolio was identified.

6.4 PORTFOLIO CONSOLIDATION

Stakeholders determined the two futures assessed in the 2020 ITP would be treated equally to determine the consolidated portfolio. When determining whether projects should move forward into the consolidated portfolio, three scenarios could occur:

1. The same project was identified in each future,
2. Two projects were competing against each other, or
3. A single project was identified in only one future.

If the same project was identified in both futures, that project would move forward into the consolidated portfolio. For the remaining scenarios, an independent method was necessary to assess each project and determine which, or if, those projects should move forward in the process.

To evaluate these scenarios, SPP and its stakeholders developed a comprehensive scoring rubric considering both quantitative and qualitative metrics. Quantitative metrics included APC and the percentage of congestion relieved. Qualitative metrics included giving credit to projects able to address operational congestion or non-thermal issues. Table 6.7 details the scoring rubric as well as some of the minimum criteria projects had to meet to receive points. SPP staff and stakeholders agreed that although this scoring methodology is a good way to measure a project's effectiveness, it should not be the only input to project selection. Stakeholders and SPP staff agreed a project narrative might be necessary when a preferred project is recommended against the results of the consolidation process.

All short-circuit and reliability projects were included in the consolidated portfolio; therefore, consolidation considerations in this assessment applied to economic projects only. A detailed description of the consolidation methodology and scoring rubric can be found in the 2020 ITP Scope.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C ratio in selected future	50	1.0 (0.9)
	40-year (1-year) APC B/C ratio in opposite future		0.8 (0.7)
	40-year (1-year) APC net benefit in selected future ($M)		N/A
	40-year (1-year) APC net benefit in opposite future ($M)		N/A
2	Congestion relieved in selected future (by need(s), all years)	10	N/A
	Congestion relieved in opposite future (by need(s), all years)	10	N/A
3	Operational congestion costs or reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate non-thermal issues	7.5	Y/N
6	Long-term viability (*e.g.*, 2013 ITP20) or improved Auction Revenue Right (ARR) feasibility	5	Y/N
	Total Points Possible:	**100**	

Table 6.7: Consolidated Portfolio Scoring Consolidation Scenario One

Six economic projects were included in both the Future 1 and Future 2 final portfolios; they were also included in the consolidated portfolio. These projects are:

- Russett-South Brown 138 kV rebuild
- Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV
- Franks-South Crocker-Lebanon 161 kV terminal equipment
- Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line
- Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment
- Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in

6.4.1 CONSOLIDATION SCENARIO TWO

Consolidation scenario two occurred when a different project was identified to solve the same or similar economic needs in each future. When this scenario occurred, it was clear a project was needed to address congestion in the models, but the consolidation methodology would be used to identify the better project. For this scenario, the scoring rubric identified in Table 6.7 was used to score the projects and determine which project should move forward into the consolidated portfolio.

In the 2020 ITP, two instances of scenario two occurred. These instances and their scoring are detailed in Table 6.8 and Table 6.9. Winning projects based on the consolidation scoring are shown in bold.

Project	Driving Future	APC Benefit	Congestion Relieved	Operational Congestion	New EHV	Non-Thermal	Long-term Viability	Total
Oahe-Sully Buttes-Whitlock-Glenham-Campbell 230 kV terminal equipment	1	0	20	0	0	0	0	20
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	**2**	**50**	**20**	**0**	**0**	**0**	**0**	**70**

Table 6.8: Consolidation Scenario Two Scoring

Project	Driving Future	APC Benefit	Congestion Relieved	Operational Congestion	New EHV	Non Thermal	Long-term Viability	Total
Anadarko-Gracemont 138 kV rebuild as double-circuit	1	46.2	20	10	0	0	0	76.2
Anadarko-Gracemont rebuild, Anadarko-Southwest Station terminal equipment 138 kV	**2**	**50**	**17.9**	**10**	**0**	**0**	**0**	**77.9**

Table 6.9: Consolidation Scenario Two Scoring

Although the Gracemont-Anadarko rebuild and Southwest Station-Anadarko terminal equipment scored higher, SPP staff recommended moving forward with the Gracemont-Anadarko double-circuit instead of the rebuild recommended by the scoring. The single circuit rebuild of Anadarko-Gracemont did not fully resolve the congestion in the area (hence the 17.9 vs. 20 score for that consideration), and SPP staff concluded that congestion in the area will continue to increase. The double circuit resolves the congestion fully, while also provides an additional path from the 345 kV hub at Gracemont. For these reasons, SPP staff recommended the double circuit instead.

6.4.2 CONSOLIDATION SCENARIO THREE

Consolidation scenario three occurred when a project was identified in only one of the two final future portfolios. When this situation occurred, the question remained whether a project driven by a single future should ultimately be recommended. For this scenario, the scoring rubric was used as a way to identify if a project should be included in the consolidated portfolio by achieving a minimum score of 70 points. Projects that did not meet the minimum scoring threshold but were recommended to be included have additional qualitative information justifying their inclusion.

GRDA 345/161 kV Transformer

The GRDA 345/161 kV transformer replacement originated from the Future 1 portfolio. The project performed well when compared to expected congestion in both futures, as well as resolved current operational needs. Therefore, the transformer replacement was added to the final portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	19.9
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	10
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**79.9**

Table 6.10: GRDA 345/161 kV transformer Consolidation Scoring

Columbus East 230/115 kV transformer

The Columbus East transformer replacement also originated from the Future 1 portfolio. This project did well in both futures while also addressing current operational congestion, ultimately resulting in inclusion in the final portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		

No.	Consideration	Possible Points	Project Score
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	9
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**79**

Table 6.11: Columbus East 230/115 kV transformer Consolidation Scoring

Lebanon-Franks-Crocker 161 kV terminal equipment

The Lebanon-Franks-Crocker 161 kV terminal equipment upgrade also originated from the Future 1 portfolio. This project did well in both futures, but did not address any current operational needs. It also did not qualify for additional points via considerations 4 through 6. However, it did reach the minimum threshold of 70 points, resulting in final portfolio inclusion.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**70**

Table 6.12: Lebanon-Franks-Crocker 161 kV terminal equipment Consolidation Scoring

Split Rock 345/115 kV Transformer

The Split Rock 345/115 kV transformer originated from the Future 2 portfolio. This project did well in both futures. However, it did not qualify for any points from considerations 3 through 6 and did not reach the 70 point threshold. It did not resolve any operational congestion within the two-year span (6/1/2018-6/1/2020) considered for consolidation. However, the Split Rock transformer began experiencing congestion after that time period. Due to this fact, SPP staff chose to include that congestion in consideration 3.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50

No.	Consideration	Possible Points	Project Score
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	19.9
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0.1
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
	Total Score (minimum 70 threshold)		**70**

Table 6.13: Lebanon-Franks-Crocker 161 kV terminal equipment Consolidation Scoring

6.5 FINAL CONSOLIDATED PORTFOLIO

The consolidated portfolio includes the reliability projects addressing both steady state and short-circuit needs, as well as the consolidated set of economic projects that met the consolidation criteria. The consolidated portfolio totals $500.2M and is projected to create $1B to $2B in APC savings under Future 1 or Future 2 assumptions, respectively. **Error! Reference source not found.** lists the projects included in the final consolidated portfolio along with their classifications and costs. Benefit data reported in this section includes only APC savings.

Project	Classification	Project Cost (2020$)
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	Reliability	$3,562,780
Circleville-Goff 115 kV circuit 1 rebuild	Reliability	$12,114,772
Goff-Kelly 115 kV rebuild	Reliability	$7,108,395
South Shreveport-Wallace Lake 138 kV rebuild	Reliability	$23,622,577
Grady 138 kV capacitor bank	Reliability	$688,781
Deaf Smith #6-Hereford 115 kV rebuild	Reliability	$6,660,556
Deaf Smith #6-Friona 115 kV rebuild	Reliability	$12,626,190
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	Reliability	$11,394,000
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	Reliability	$5,362,799
Bushland-Deaf Smith 230 kV terminal equipment	Reliability	$923,938
Newhart-Potter County 230 kV terminal equipment	Reliability	$731,282
Carlisle-Murphy 115 kV rebuild	Reliability	$4,746,175
Replace Roswell 115/69 kV transformer	Reliability	$2,777,743
S3456-S3458 345 kV terminal equipment	Reliability	$678,865
Meadowlark-Tower 33 115 kV rebuild	Reliability	$1,342,588
Jones-Lubbock South 230 kV terminal equipment circuit 1	Reliability	$666,728
Jones-Lubbock South 230 kV terminal equipment circuit 2	Reliability	$397,668

Project	Classification	Project Cost (2020$)
Deaf Smith-Plant X 230 kV terminal equipment	Reliability	$2,100,196
Newhart-Plant X 230 kV terminal equipment	Reliability	$2,024,293
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	Reliability	$872,391
Allen-Lubbock South 115 kV rebuild	Reliability	$6,817,226
Allen-Quaker 115 kV rebuild	Reliability	$4,732,267
Eddy County-North Loving 345 kV new line	Reliability	$64,422,600
Bismarck 115 kV reactors	Reliability	$2,380,700
Moorehead 230 kV reactor	Reliability	$1,515,440
Russell 115 kV capacitor bank	Reliability	$2,841,951
Maljamar 115 kV capacitor bank	Reliability	$685,440
Devil's Lake 115 kV reactor	Reliability	$1,190,000
Agate 115 kV reactor	Reliability	$571,200
Replace four breakers at Anadarko 138 kV	Short Circuit	$850,000
Replace three breakers at Northeast 161 kV	Short Circuit	$887,479
Replace one breaker at Stilwell 161 kV	Short Circuit	$566,485
Replace one breaker at Leeds 161 kV	Short Circuit	$566,485
Replace one breaker at Shawnee Mission 161 kV	Short Circuit	$566,485
Replace one breaker at Southtown 161 kV	Short Circuit	$566,485
Replace two breakers at Lake Road 161 kV	Short Circuit	$1,132,970
Replace two breakers at Craig 161 kV	Short Circuit	$1,132,970
Anadarko-Gracemont 138 kV rebuild as double-circuit	Economic	$8,297,502
Russett-South Brown 138 kV rebuild	Economic	$10,067,432
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	Economic	$135,720,424
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	Economic	$1,410,000
Columbus East 230/115 kV transformer replacement	Economic	$4,600,000
Franks-South Crocker-Lebanon 161 kV terminal equipment	Economic	$5,721,430
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	Economic	$31,686,685
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	Economic	$1,617,500
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	Economic	$113,620,907
Split Rock 345/115 kV circuit 10 & 11 terminal equipment	Economic	$4,577,336
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	Economic	$1,528,722[23]

Table 6.14: Final Consolidated Portfolio

---

[23] Estimated cost does not include the entire cost for this project.

Table 6.15 shows the Future 1 and Future 2 40-year B/C ratio and net benefit of the economic projects in 2020$ included in the consolidated portfolio using the same process described in the Section 6.2.4.1 for project subtraction evaluation.

Project	Project Cost (E&C)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit	F1 40-year Net Benefit	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit	F2 40-year Net Benefit
Anadarko-Gracemont 138 kV rebuild as Ckt	$8,297,502	2.88	4.28	8.35	$107,624,325	$94,731,224	5.35	3.09	4.56	$58,831,889	$45,938,788
Russett-South Brown 138 kV rebuild	$10,067,432	0.00	1.50	3.38	$52,833,714	$37,190,402	7.56	12.23	24.16	$377,875,070	$362,231,757
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	$135,720,424	0.75	1.00	1.91	$403,001,375	$192,111,748	1.06	1.37	2.62	$552,029,756	$341,140,129
GRDA 1 345/161 kV Ckt 1 and Ckt 2 terminal equipment	$1,410,000	13.98	20.09	38.98	$85,412,599	$83,221,666	7.15	5.38	8.90	$19,506,220	$17,315,287
Columbus East 230/115 kV transformer replacement	$4,600,000	0.20	0.50	1.05	$7,486,072	$338,347	2.02	3.27	6.46	$46,175,084	$39,027,359
Franks-South Crocker-Lebanon 161 kV terminal equipment	$5,721,430	(0.31)	2.04	4.74	$42,160,359	$33,270,096	0.01	0.90	2.02	$17,981,132	$9,090,869
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	$31,686,685	1.32	1.63	3.07	$151,237,189	$102,000,729	2.16	1.99	3.52	$173,144,070	$123,907,610
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	$1,617,500	51.34	82.75	163.37	$410,605,871	$408,092,513	13.52	21.06	41.36	$103,963,767	$101,450,410
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment, and Pleasant Valley cut-in	$113,620,907	0.81	1.33	2.62	$462,634,382	$286,084,161	1.28	2.72	5.56	$980,999,837	$804,449,617
Split Rock 345/115 kV Ckt 10 and 11 terminal equipment	$4,577,336	0.09	(0.06)	(0.16)	($1,171,751)	($8,284,260)	1.72	8.83	19.12	$136,025,615	$128,913,106
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment	$1,528,722[24]	2.01	2.19	4.04	$9,593,533	$8,166,644	2.09	2.71	5.17	$12,275,136	$11,200,631

Table 6.15: Consolidated Portfolio – APC benefit only

---

[24] Estimated cost does not include the entire cost for this project.

Table 6.16 below shows the change in flowgate congestion scores due to the consolidated portfolio for the economic needs targeted by the portfolio.

	Base Congestion Score (k$/MWh)					Consolidated Portfolio Congestion Score (k$/MWh)				
	Future 1			Future 2		Future 1			Future 2	
Constraint	2022	2025	2030	2025	2030	2022	2025	2030	2025	2030
Russett-South Brown 138 kV FLO Caney Creek-Little City 138 kV	0	0	196	277	497	0	0	0	0	0
GRDA 345/161 kV circuit 1 FLO GRDA 345/161 kV circuit 2	11	39	49	16	19	0	0	0	0	0
Southwestern Station-Anadarko 138 kV FLO Gracemont-Anadarko 138 kV	0	0	1	0	1	0	0	0	0	0
Dover Switch-Okeene 138 kV FLO Watonga-Okeene 138 kV	238	503	885	213	334	0	0	0	0	0
Oahe-Sully Buttes 230 kV FLO Fort Thompson-Leland Olds 345 kV	0	33	48	45	118	0	0	0	0	0
Butler-Altoona 138 kV FLO Caney River-Neosho 345 kV	770	1,187	1,688	1,574	1,722	0	0	0	0	0
Columbus East 230/115 kV FLO Columbus East-Shell Creek 345 kV	2	41	50	51	79	0	0	0	0	0
Watford 230/115 kV circuit 1 FLO Watford 230/115 kV circuit 2	130	157	366	184	354	0	0	0	0	0
Shamrock 115/69 kV FLO Sweetwater-Chisholm 230 kV	5	7	20	9	24	0	1	3	2	5
Skyline-Quail Creek 138 kV FLO Northwest-Arcadia 345 kV	0	5	28	12	82	0	0	6	0	59
Czech Hall-Cimarron 138 kV FLO Cimarron-Draper 345 kV	1	10	30	41	88	0	0	0	0	0
Cimarron 345/138 kV circuit 1 FLO Cimarron 345/138 kV circuit 2	11	33	85	36	125	0	3	11	3	29
Franks-Crocker 161 kV FLO Huben-Franks 345 kV	18	5	99	8	41	0	0	0	0	0
Split Rock 345/115 kV circuit 10 FLO Split Rock 345/115 kV circuit 11	0	1	3	22	103	0	0	0	0	1

Table 6.16: Change in flowgate congestion scores

Figure 6.8 shows the B/C ratio of the economic portfolio of projects[25] included in the consolidated portfolio. Figure 6.9 shows B/C ratio of the entire consolidated portfolio. As expected, the overall B/C ratio is reduced with the inclusion of the reliability projects, but the consolidated portfolio is still expected to produce benefits well over the cost of the projects.

---

[25] Includes projects driven by market powerflow models not already identified in the base reliability portfolio.

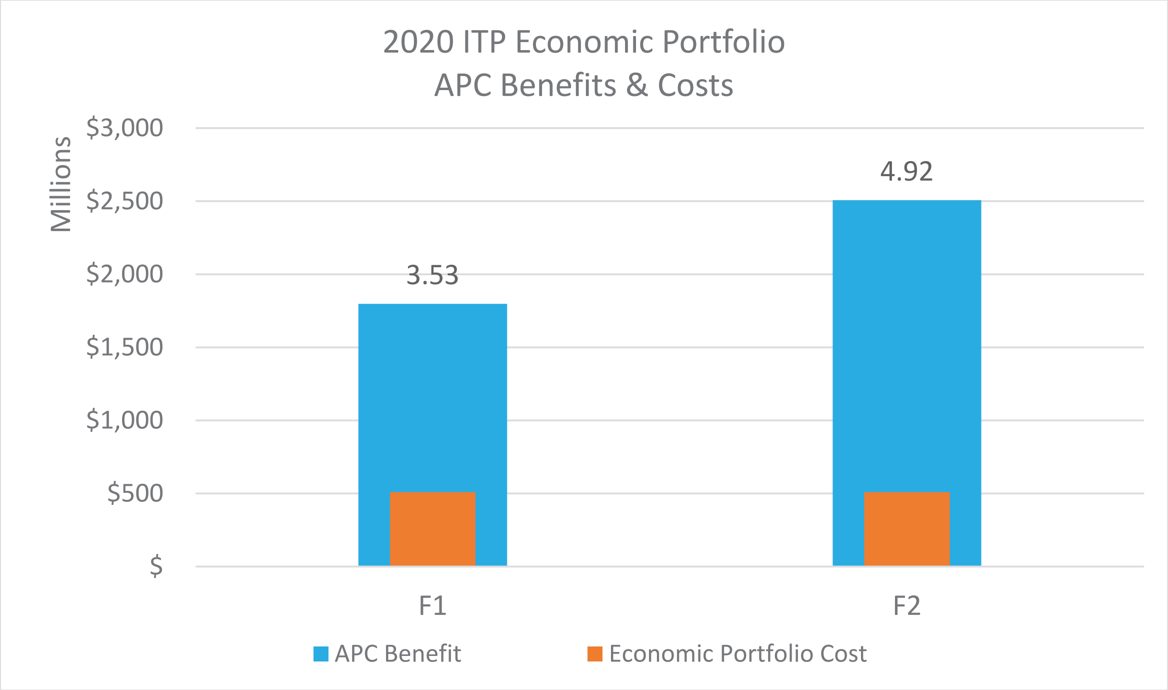


Figure 6.8: Economic Portfolio APC Benefits and Costs

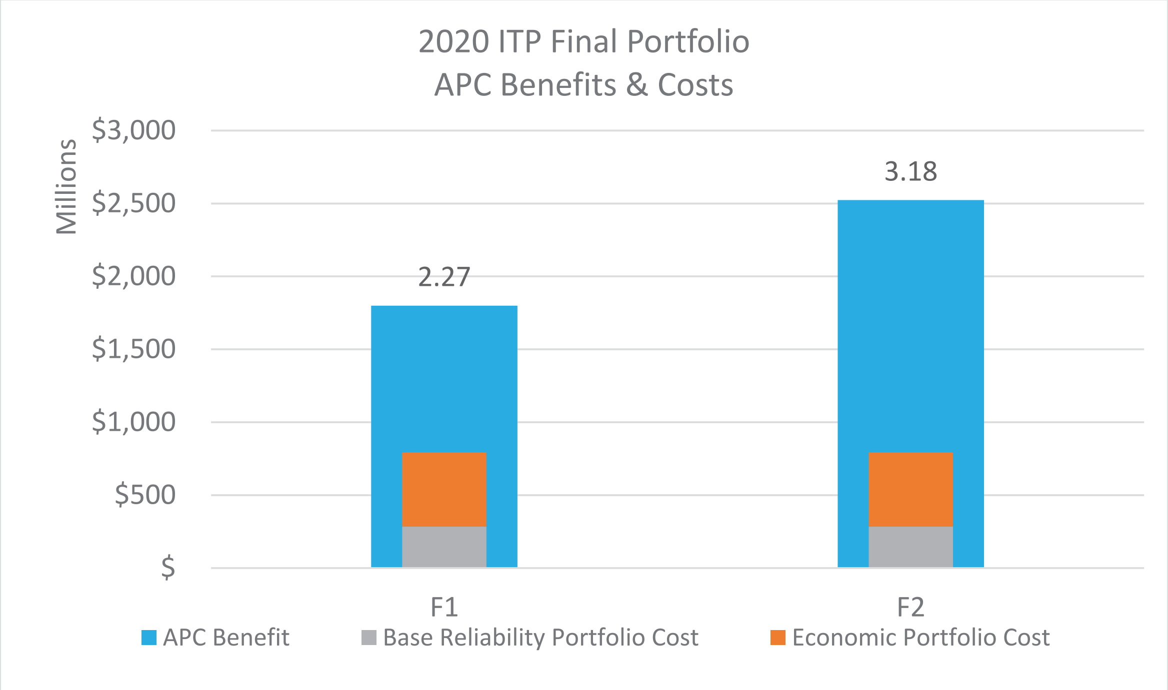


Figure 6.9: Final Consolidated Portfolio APC Benefits and Costs

Figure 6.10 below shows the break-even and payback dates of the consolidated portfolio. The break-even year is reflective of the first year that the one-year APC benefits are expected to outweigh the portfolio ATRR. The payback year is reflective of the year that the cumulative APC benefits are expected to exceed the 40-

year NPV costs of the portfolio. The consolidated portfolio is expected to breakeven within the first year of being placed in service and expected to pay back total investment within the first 20 years.

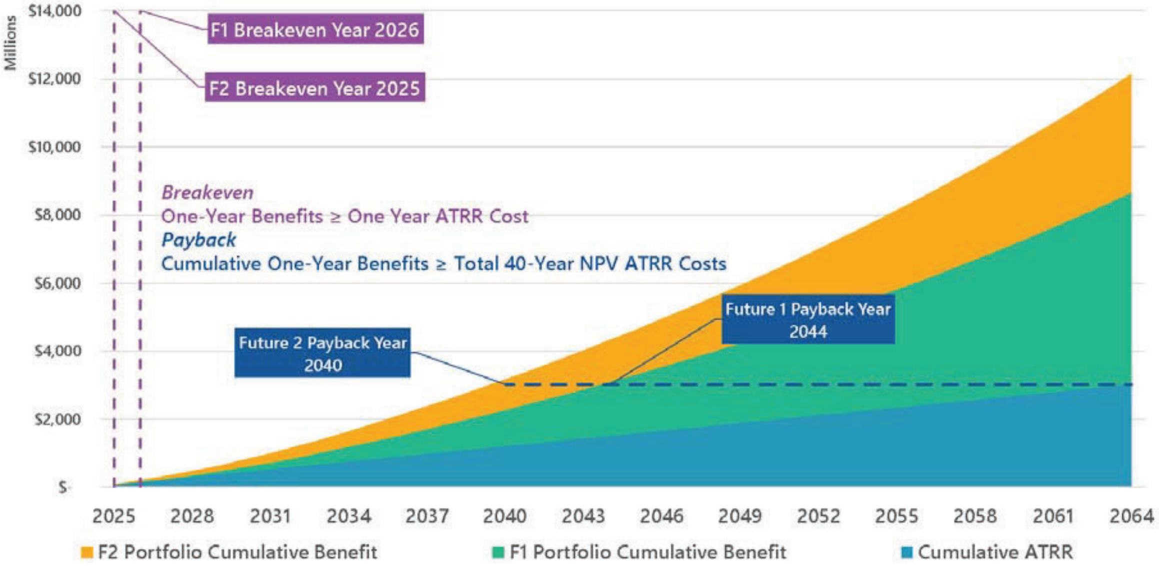


Figure 6.10: Portfolio Breakeven and Payback – APC benefit only

6.6 STAGING

Staging is the process by which the need date and projected in-service date for each project is determined. The staging methodology can be found in the ITP Manual.

6.6.1 ECONOMIC PROJECTS

The results of staging for the economic projects are shown in Table 6.17 below.

Economic Project	Need Date	Projected In-Service Date	Model
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	1/1/2022	11/17/2022	F1/F2
Anadarko-Gracemont 138 kV rebuild as double-circuit	1/1/2023	11/17/2023	F1
Russett-South Brown 138 kV rebuild	1/1/2022	5/17/2023	F1/F2
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	1/1/2024	1/1/2024	F1/F2
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	1/1/2022	5/17/2022	F1
Columbus East 230/115 kV transformer replacement	1/1/2039	1/1/2039	F1
Franks-South Crocker-Lebanon 161 kV terminal equipment	1/1/2028	1/1/2028	F1

Economic Project	Need Date	Projected In-Service Date	Model
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	1/1/2022	11/17/2024	F1/F2
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	1/1/2022	5/17/2022	F1/F2
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	1/1/2025	1/1/2025	F1/F2
Split Rock 345/115 kV circuit 10 & 11 terminal equipment	1/1/2025	1/1/2025	F2
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment[26]	1/1/2022	5/17/2022	F2

Table 6.17: Project Staging Results-Economic

6.6.2 POLICY PROJECTS

There were no policy-driven projects in the 2020 ITP.

6.6.3 RELIABILITY PROJECTS

The results of staging for the reliability projects are shown in Table 6.18 below. The Watford transformer upgrade will have a need date of January 1, 2022 because the economic staging need date is earlier than the reliability staging need date.

Reliability Project	Need Date	Projected In-Service Date	Model
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	6/1/2022	11/17/2022	BR
Circleville-Goff 115 kV circuit 1 rebuild	6/1/2025	6/1/2025	BR
Goff-Kelly 115 kV rebuild	6/1/2025	6/1/2025	BR
South Shreveport-Wallace Lake 138 kV rebuild	6/1/2024	6/1/2024	BR
Grady 138 kV capacitor bank	12/1/2022	12/1/2022	LPC
Deaf Smith #6-Hereford 115 kV rebuild	6/1/2022	5/17/2023	BR
Deaf Smith #6-Friona 115 kV rebuild	4/1/2022	11/17/2022	BR
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	12/1/2022	11/17/2023	BR

---

[26] The projected need date was calculated using an incomplete cost estimate. See Table 9.1 for accurate need and projected in-service dates.

Reliability Project	Need Date	Projected In-Service Date	Model
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	6/1/2023	6/1/2023	BR
Bushland-Deaf Smith 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Newhart-Potter County 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Carlisle-Murphy 115 kV rebuild	6/1/2022	11/17/2022	BR
Replace Roswell 115/69 kV transformer	6/1/2022	11/17/2022	BR
S3456-S3458 345 kV terminal equipment	6/1/2029	6/1/2029	BR
Meadowlark-Tower 33 115 kV rebuild	6/1/2023	11/17/2023	BR
Jones-Lubbock South 230 kV terminal equipment circuit 1	6/1/2028	6/1/2028	BR
Jones-Lubbock South 230 kV terminal equipment circuit 2	6/1/2028	6/1/2028	BR
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Newhart-Plant X 230 kV terminal equipment	4/1/2022	5/17/2022	BR
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	6/1/2022	6/1/2022	BR
Allen-Lubbock South 115 kV rebuild	6/1/2022	11/17/2022	BR
Allen-Quaker 115 kV rebuild	6/1/2022	11/17/2022	BR
Eddy County-North Loving 345 kV new line	6/1/2028	6/1/2028	BR
Bismarck 115 kV reactors	4/1/2022	11/17/2022	BR/MPM
Moorehead 230 kV reactor	4/1/2022	11/17/2022	BR/MPM
Russell 115 kV capacitor bank	6/1/2022	11/17/2022	MPM
Maljamar 115 kV capacitor bank	6/1/2028	6/1/2028	MPM
Devil's Lake 115 kV reactor	4/1/2022	11/17/2022	MPM
Agate 115 kV reactor	4/1/2022	11/17/2022	MPM
Nixa-Nixa Espy 69 kV terminal equipment	6/1/2022	6/1/2022	BR

Table 6.18: Project Staging Results-Reliability

6.6.4 SHORT-CIRCUIT PROJECTS

The short-circuit projects were all staged with need dates and projected in-service dates of June 1, 2022.

7 PROJECT RECOMMENDATIONS

7.1 RELIABILITY PROJECTS

7.1.1 WATFORD 230/115 KV TRANSFORMERS

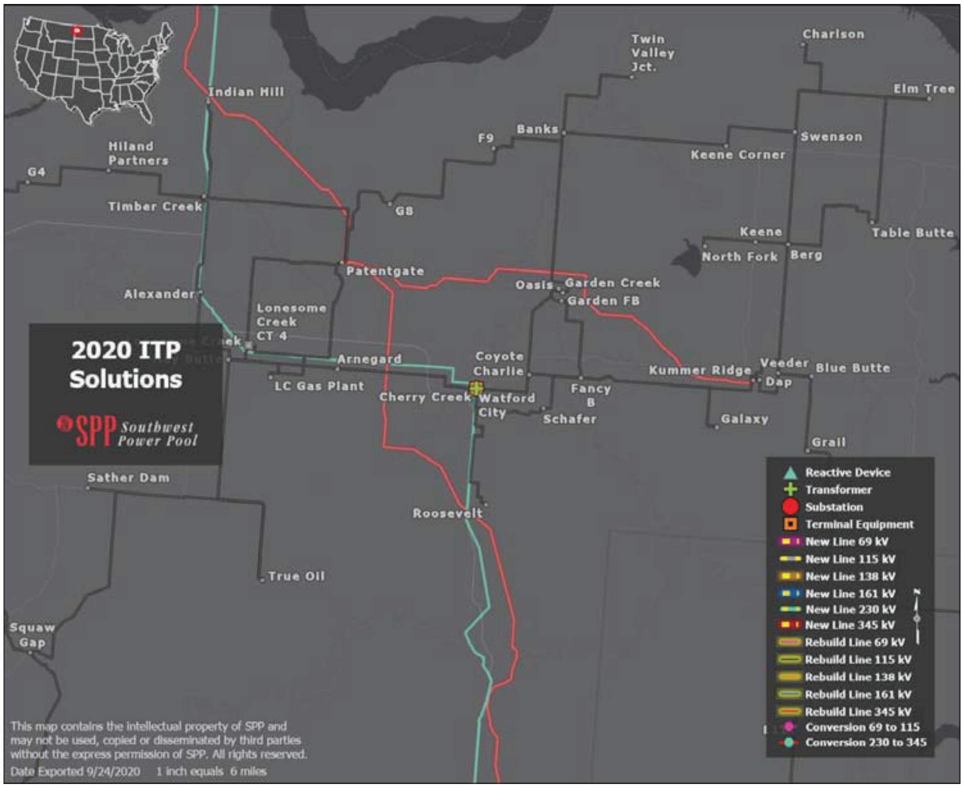


Figure 7.1: Watford 230/115 kV Transformers

In western North Dakota, the Watford City transformers that serve the 115 kV system experience both reliability violations and system congestion when one of the transformers is lost. The area around Watford has experienced expanded oil exploration and increasing load growth to support the shale play. Multiple solutions, including a new delivery point to support the increasing load, were analyzed but this area continues to grow and is expected to be of greater concern in future ITP assessments. The selected project is a no-regrets solution to strengthen the transformation at Watford by upgrading terminal equipment on one 230/115 kV transformer and replacing the other transformer to increase the capacity in cases where one is lost.

7.1.2 AMARILLO NORTH-SOUTH 230 KV CORRIDOR TERMINAL EQUIPMENT AND LINE CLEARANCES

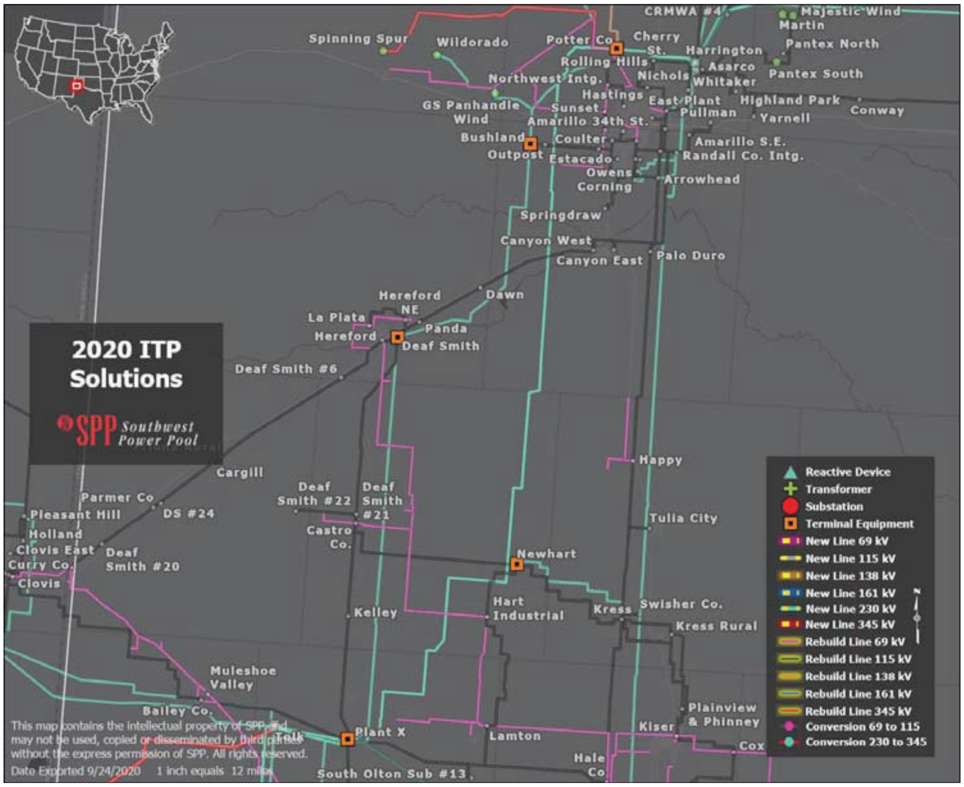


Figure 7.2: Amarillo North-South 230 kV Corridor Terminal Equipment

The Bushland-Deaf Smith 230 kV line and the Potter-Newhart-Plant X 230 kV line run parallel in a north-to-south direction near the city of Amarillo, Texas. When one of these 230 kV paths is out of service, an overload is observed on the parallel path. During light load conditions paired with a high wind output, generation in the south is no longer needed. This combination results in large north-to-south flows coming out of Amarillo. Given that each of these lines are terminally limited and the conductor can handle the observed post-contingency flows, the projects selected to mitigate these issues is to replace any terminal equipment that is limiting these three 230 kV line segments below their conductor rating, as well as increase the height of necessary structures to create appropriate line clearances.

7.1.3 HEREFORD-CURRY 115 KV CORRIDOR REBUILDS

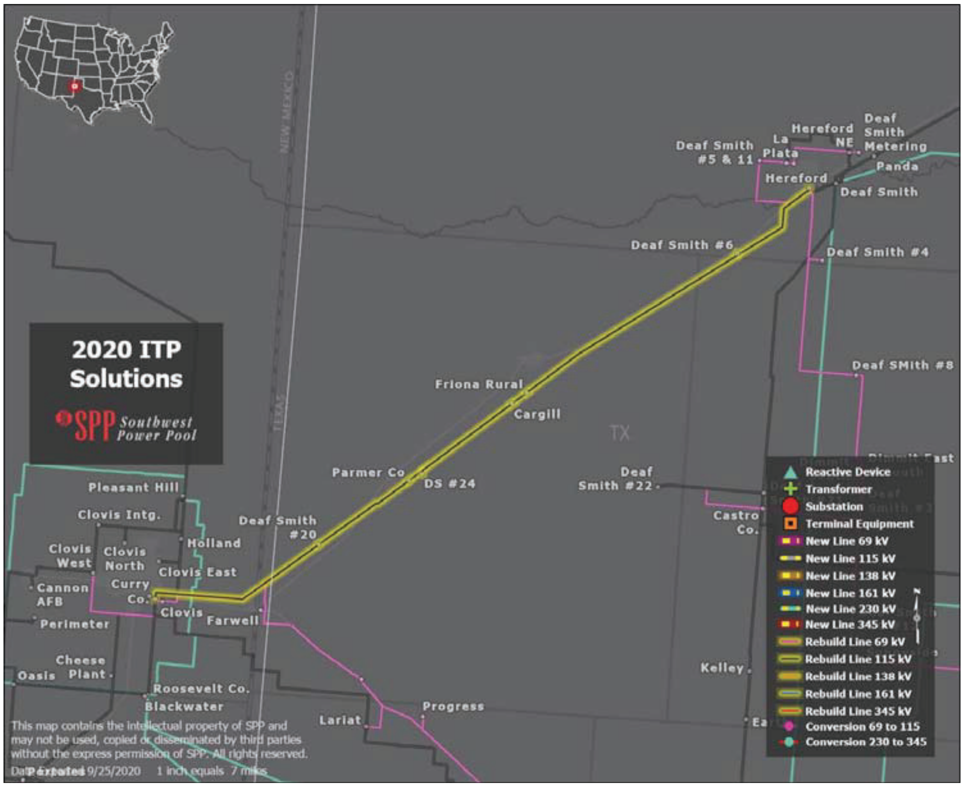


Figure 7.3: Hereford-Curry 115 kV Corridor Rebuild

Southwest of Amarillo, in a series corridor between Amarillo, Texas, and Clovis, New Mexico, seven 115 kV line segments overload for the loss of the Deaf Smith-Plant X 230 kV line. Similar to other needs in the Amarillo area, high wind output and less conventional generation south of Amarillo causes flows on the 115 kV corridor to overload upon loss of the 230 kV path. A rebuild of the Hereford-Deaf Smith #6-Friona-Cargill-Deaf Smith #24-Parmer-Deaf Smith #20-Curry 115 kV corridor is needed to bring these lines up to the same design standards of surrounding upgraded 115 kV lines and mitigate these issues. The Deaf Smith #20-Curry 115 kV portion of this corridor was identified as having been previously approved via a separate planning process with an expected in-service date prior to the ITP need date. Therefore, no NTC will be issued for this facility.

7.1.4 JONES-LUBBOCK SOUTH 230 KV TERMINAL EQUIPMENT

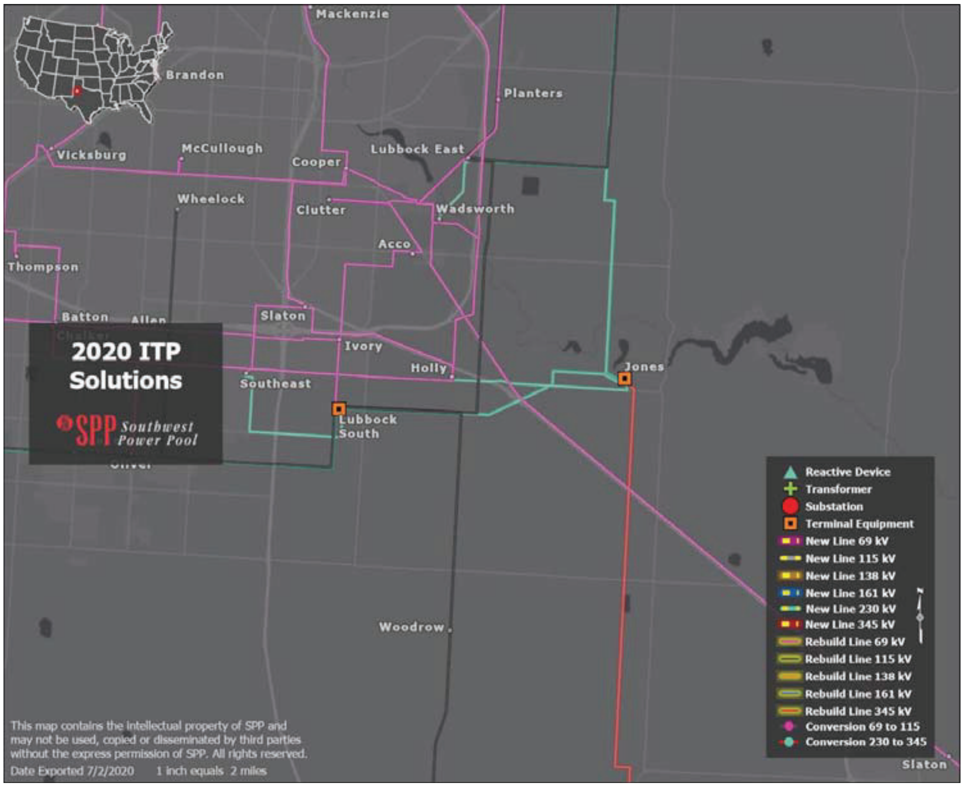
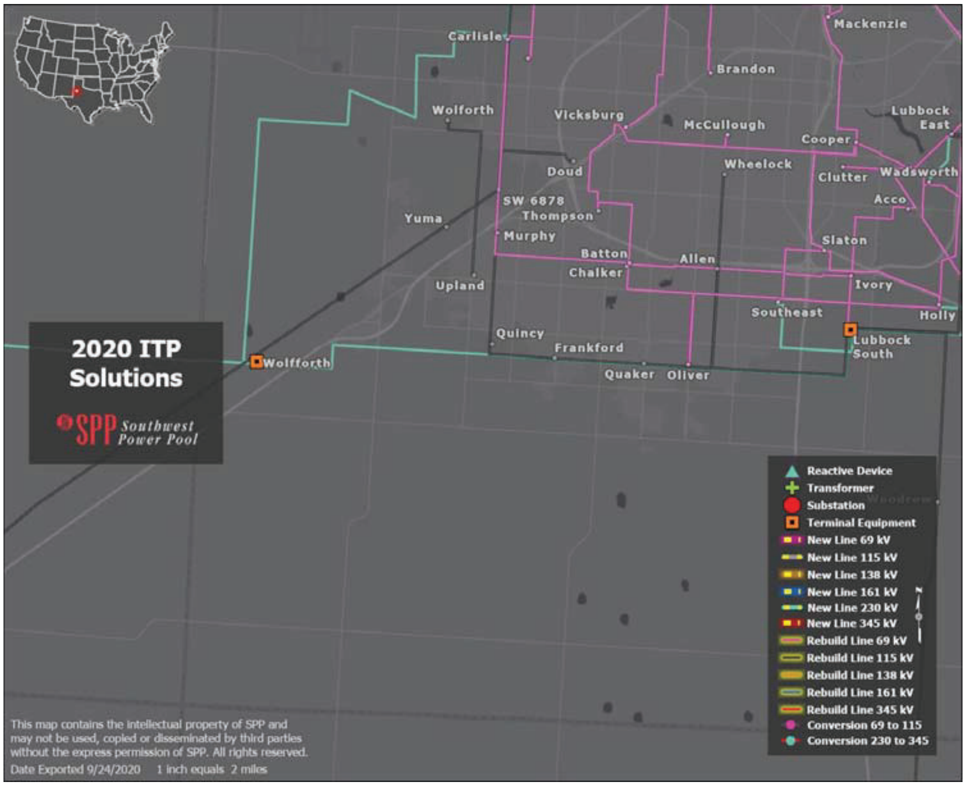


Figure 7.4: Jones-Lubbock South 230 kV Terminal Equipment

On the south end of Lubbock, Texas, in the Texas Panhandle, two parallel 230 kV circuits from Jones to Lubbock South each overload upon contingency of the other circuit. This 230 kV corridor is a common pass-through to deliver energy to the SPS south area. In addition, the fact that the Lubbock South substation feeds a large portion of the Lubbock load center, combined with maximum output of the Jones plant, causes these circuits to overload in contingency conditions during the long-term summer peaks. Given that the ratings of these lines are driven by terminal equipment and the conductors can handle the post-contingency flows, the project selected to mitigate this issue is to upgrade the necessary terminal equipment at these substations and allow the conductors to become the most limiting element long each path.

7.1.5 LUBBOCK SOUTH-WOLFFORTH 230 KV TERMINAL EQUIPMENT AND LINE CLEARANCES

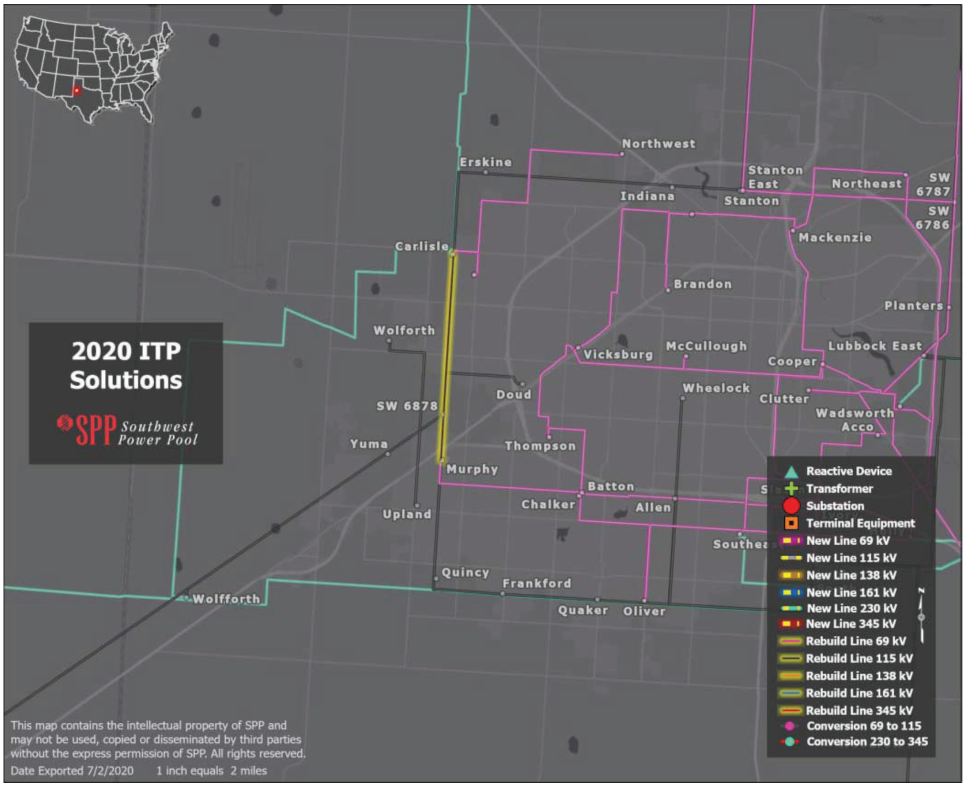


This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.
Date Exported 9/24/2020 1 inch equals 2 miles

Figure 7.5: Lubbock South-Wolfforth 230 kV Terminal Equipment and Line Clearances

On the south end of Lubbock, Texas, in the Texas Panhandle, the Lubbock South-Wolfforth 230 kV line reaches near base-case overloads in the near-term winter peaks and the long-term summer peaks. The Lubbock South-Wolfforth line is a large feed to deliver energy in the SPS south area which contributes to this base-case flow. Since the flow is already approaching the line rating, many contingencies in the area can cause the line to overload. The project selected to mitigate this issue is to upgrade the terminal equipment limiting the line rating below the conductor rating, as well as increase the height of necessary structures to create appropriate line clearances.

7.1.6 CARLISLE-MURPHY 115 KV REBUILD



This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.
Date Exported 7/2/2020 1 inch equals 2 miles

Figure 7.6: Carlisle-Murphy 115 kV

On the west side of Lubbock in the panhandle of Texas, the Carlisle-Murphy 115 kV line overloads for the loss of the Allen-Lubbock South 115 kV during the summer peaks. Loss of this 115 kV circuit forces flow to redirect around the city of Lubbock, overloading the Carlisle-Murphy 115 kV line which is serving radial load all the way through to Allen. A rebuild of the Carlisle-Murphy 115 kV line will mitigate the issue by increasing the transmission capability of that circuit.

7.1.7 EDDY COUNTY-NORTH LOVING 345 KV LINE

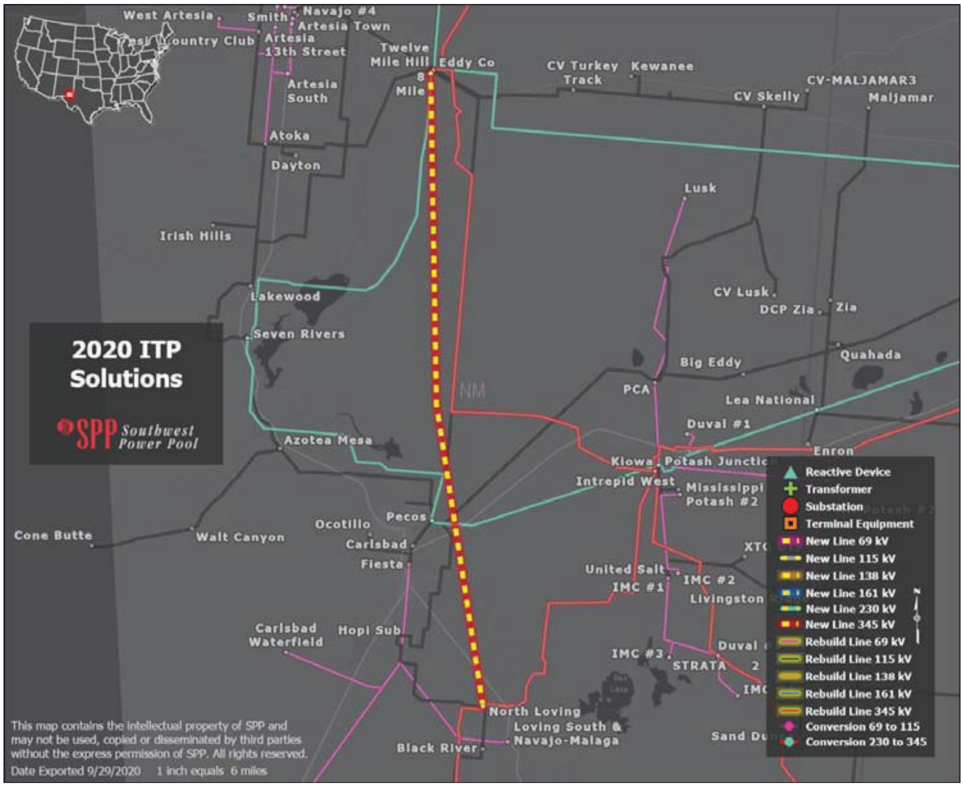


Figure 7.7: Eddy County-North Loving 345 kV

Southeast of Loving, New Mexico, the 115 kV system experiences low voltage for the loss of the Hobbs-Kiowa 345 kV line, including voltage collapse at the Phantom 115 kV bus. Increasing load, combined with a generator retirement in the south SPS area, has made this area less able to maintain minimal voltage in the long-term summer peaks upon the loss of a 345 kV feed into the area which carries critical real and reactive power support. The project selected to mitigate this issue is to construct a new 345 kV line from Eddy County-North Loving to deliver more real and reactive power support to this area.

Impactful out of scope NERC TPL-001-4 P3 planning events and SPSNMTIES interface violations in the base reliability model were identified late in the assessment and question the project's long-term viability. The NERC TPL-001-4 P3 planning events with limited system adjustment options cause voltage collapse in eastern New Mexico area in 2030 summer peak. These system conditions are related to the SPSNMTIES interface as described in section 4.1.2 and these violations were inadvertently not identified as part of the reliability needs assessment. Without these crucial system limits accounted for in reliability project screening and grouping introduces uncertainty in the large-scale project selection that has a June 2028 reliability need date.

For these reasons and consistent with delaying any action on the congested SPSNMTIES interface to future ITP cycles as described in section 6.2.6, it is recommended to not move forward with construction of this planned reliability project at this time and use the 2021 ITP to reassess this portion of the SPP system which allows for further stakeholder collaboration and opportunity to optimize base reliability solutions and potential economic solutions to identify a comprehensive solution in Eastern New Mexico area.

7.1.8 ROSWELL INTERCHANGE 115/69 KV TRANSFORMER #1 REPLACEMENT

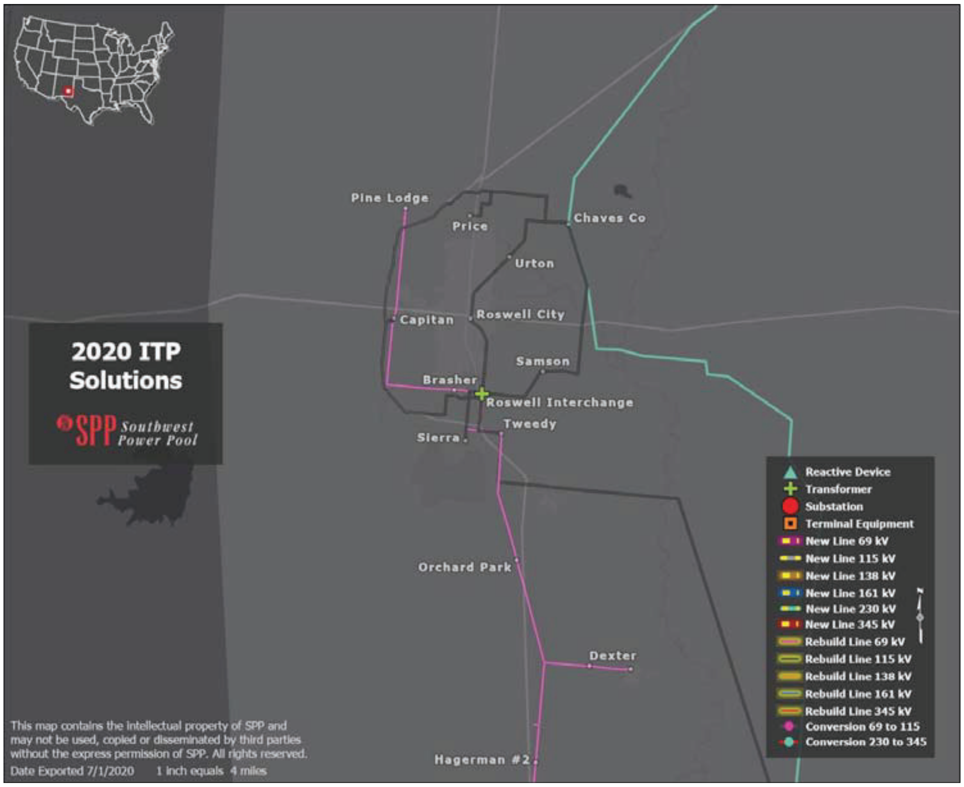


Figure 7.8: Roswell Interchange 115/69 kV Transformer #1

In the southeast corner of New Mexico in the city of Roswell, the 115/69 kV transformer #1 overloads for the loss of transformer #2. Summer peak loading conditions in Roswell, New Mexico, drives the load to levels that cannot be served through the single transformer after the contingency of transformer #2. Replacing transformer #1 with a transformer that meets the same standards as surrounding 115/69 kV transformers will mitigate this issue.

7.1.9 CUSHING TAP-SHELL CUSHING TAP-SHELL PIPELINE 69 KV REBUILD

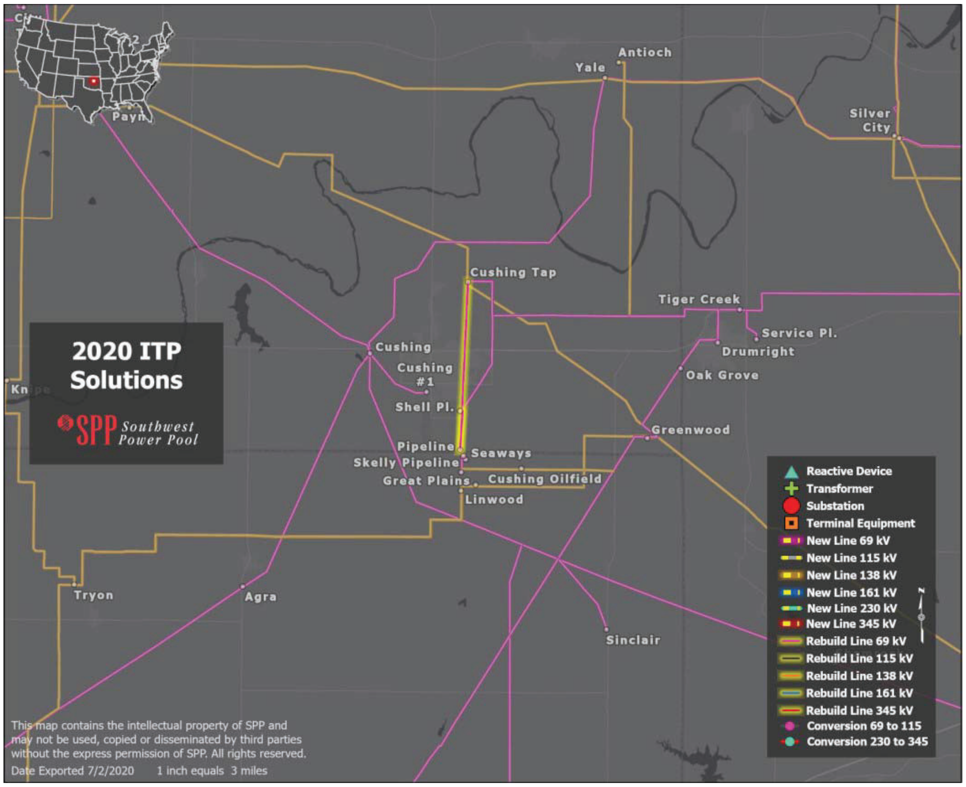


Figure 7.9: Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV

Northeast of Oklahoma City, near the town of Cushing, Oklahoma, the Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV series corridor overloads for the loss of the Highway 99 Tap-Cushing Oilfield 69 kV line. Loss of this feed places the load at Cushing Oilfield at a radial from the Cushing Tap substation, which overloads the Cushing Tap-Shell Cushing Tap 69 kV segment during the summer peaks and very nearly overloads the Shell Cushing Tap-Shell Pipeline segment. Rebuilding the Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV corridor will mitigate this issue by increasing the conductor ratings to tolerate the loss of the Highway 99 Tap-Cushing Oilfield 69 kV line.

7.1.10 SOUTH SHREVEPORT-WALLACE LAKE 138 KV REBUILD

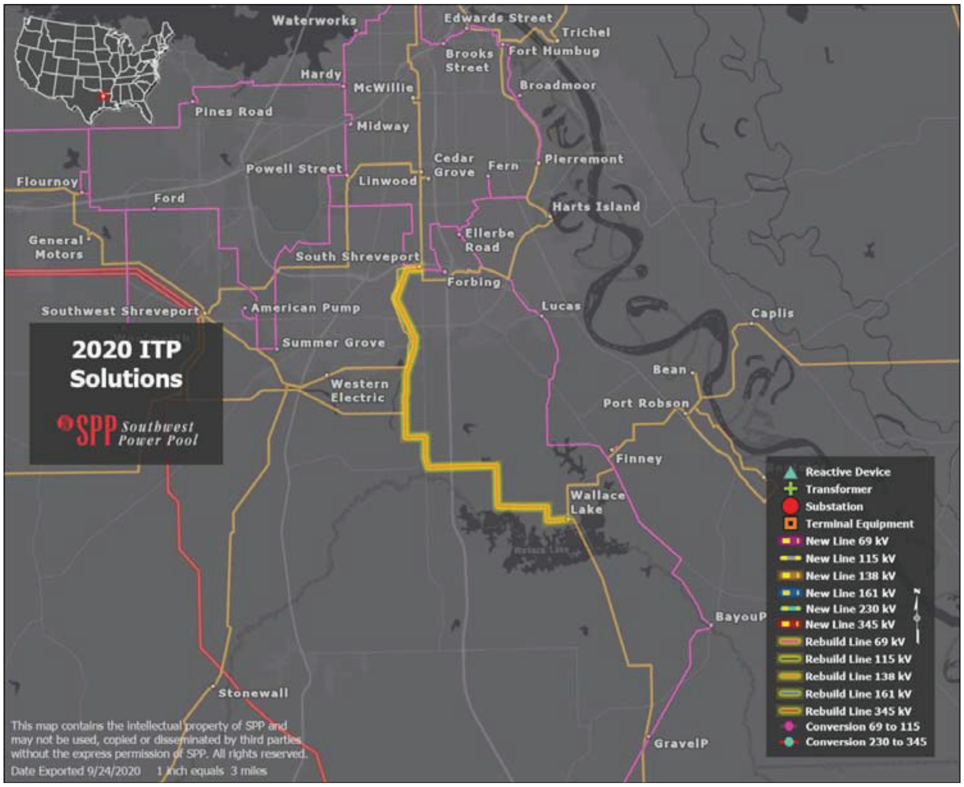


Figure 7.10: South Shreveport-Wallace Lake 138 kV

In northwest Louisiana in the city of Shreveport, the South Shreveport-Wallace Lake 138 kV line overloads for the loss of the Fort Humbug-Trichel 138 kV line. Loss of the 138 kV line which heads east out of the city causes the large amount of load across the Red River to be served out of South Shreveport. Rebuilding the South Shreveport-Wallace Lake 138 kV line will bring the facility up to the same design standards of surrounding upgraded 115 kV line and mitigate this issue.

7.1.11 GRADY 138 KV CAPACITOR BANK

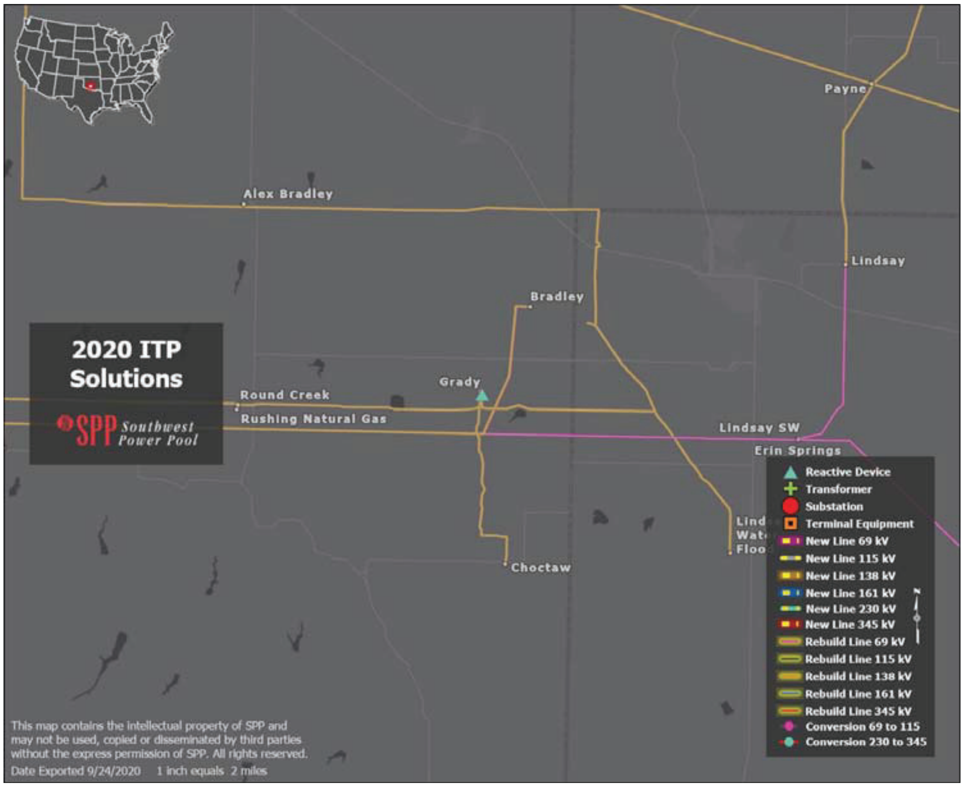


Figure 7.11: Grady 138 kV Capacitor Bank

South of Oklahoma City near the town of Lindsay, Oklahoma, the Choctaw and Grady 138 kV bus voltages dip below AEPW's minimum voltage criteria of 0.92pu for the loss of the Grady-Round Creek 138 kV line. Loss of this 138 kV feed places a large amount of load at Choctaw and Grady on a radial from the Cornville substation, bringing the voltage below acceptable levels during the summer peaks. The project selected to mitigate this issue is to place a capacitor bank capable of 23 MVAR at the Grady 138 kV substation.

7.1.12 NIXA-NIXA ESPY 69 KV TERMINAL EQUIPMENT

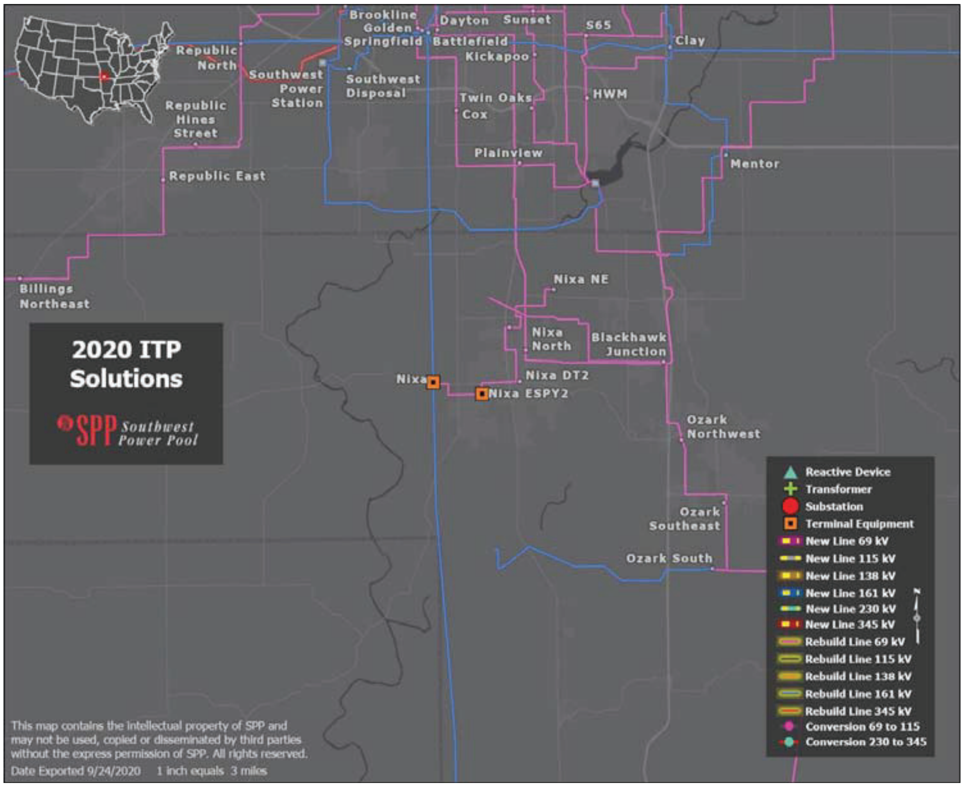


Figure 7.12: Nixa-Nixa Espy 69 kV Terminal Equipment

South of Springfield in the town of Nixa, Missouri, the Nixa-Nixa Espy 69 kV line overloads for the loss of the James River Power Station 161/69 kV transformer. Loss of the transformer causes energy to access the 69 kV system at Nixa and make its way north to serve load at Seminole and Twin Oaks, overloading the Nixa-Nixa Espy 69 kV circuit. The project selected to mitigate this issue is to upgrade the necessary 69 kV terminal equipment at Nixa and Nixa Espy which will increase the line rating up to the conductor capability.

7.1.13 MEADOWLARK-TOWER 33 115 KV REBUILD

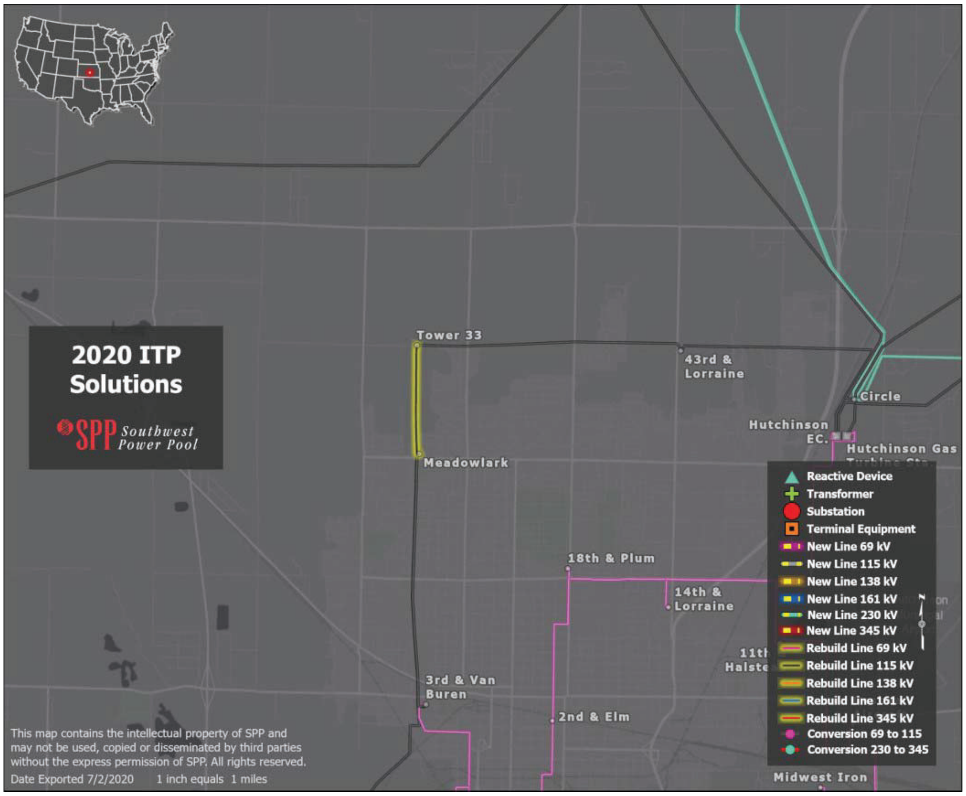


Figure 7.13: Meadowlark-Tower 33 115 kV

In the northwest corner of Hutchinson, Kansas, circuit 1 of Meadowlark-Tower 33 115 kV overloads for loss of the Davis-Reno County 115 kV line. Loss of the Davis-Reno County line causes all the load at Davis and South Hutchinson to be served radially through parallel Meadowlark-Tower 33 115 kV circuits, overloading the first circuit in the long-term summer peaks. The project selected to mitigate this issue is to rebuild the first circuit of Meadowlark-Tower 33 115 kV to increase the capacity up to the same design standards of surrounding upgraded 115 kV lines.

7.1.14 SUB 3458-SUB 3456 345 KV TERMINAL EQUIPMENT

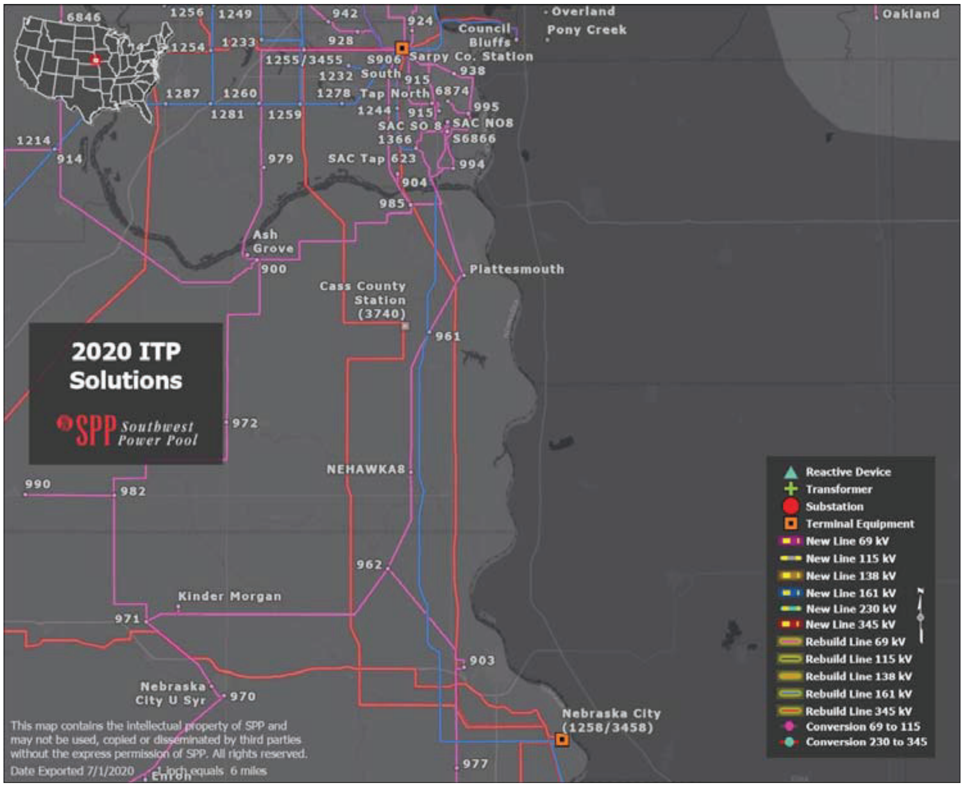


Figure 7.14: S3458-S3456 Terminal Equipment

Flowing south-to-north into the city of Omaha, Nebraska, the S3458-S3456 345 kV line overloads for the loss of the S3740-S3455 345 kV line. During the long-term summer peaks, Cass County and Nebraska City generating plants are operating at full output which overloads the northbound 345 kV line serving the city of Omaha when the parallel 345 kV line is lost. Upgrading the terminal equipment that is most limiting on the S3458-S3456 kV line will increase the rating of this line and mitigate this issue.

7.1.15 CIRCLEVILLE-GOFF-KELLY 115 KV REBUILD

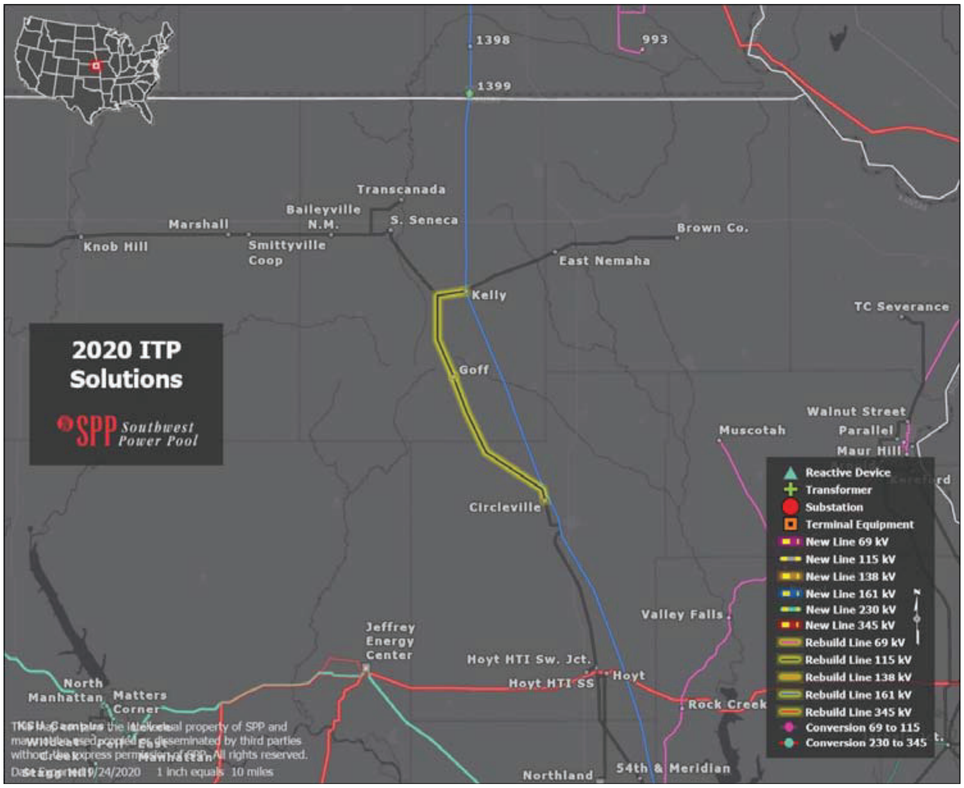
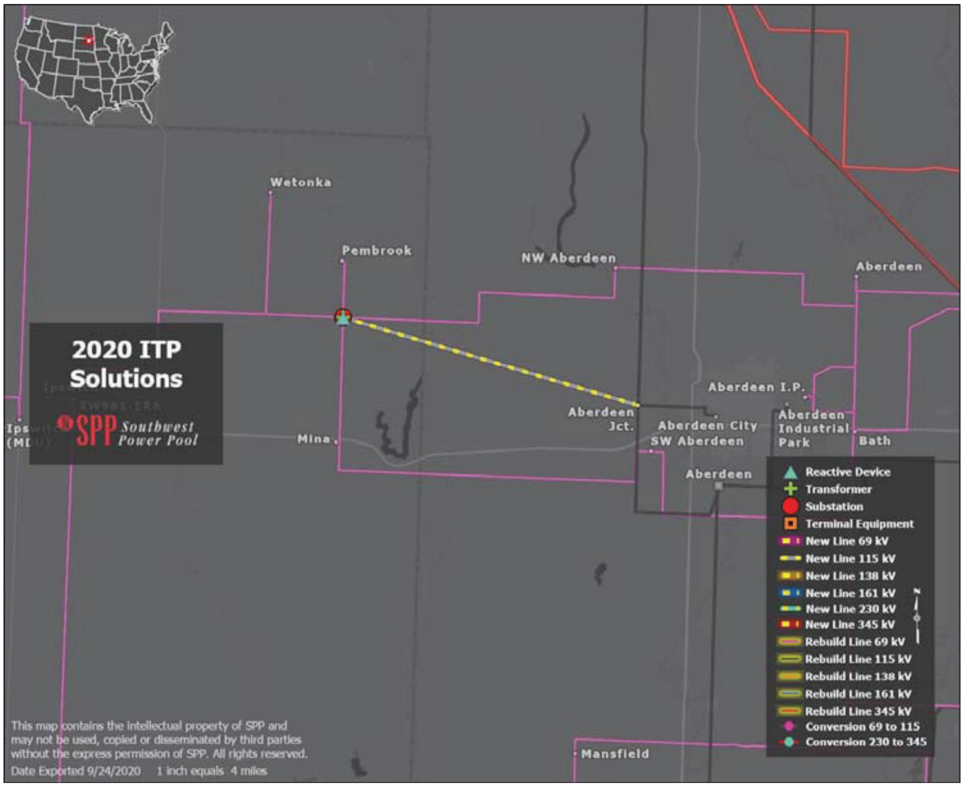


Figure 7.15: Circleville-Goff-Kelly 115 kV

North of Topeka, near the city of Circleville, Kansas, the Circleville-Goff-Kelly 115 kV lines overload for the loss of the Hoyt-Stranger Creek 345 kV line during summer peak of the Kansas City load center. Loss of the 345 kV line redirects flows down to the 115 kV system which then takes a northerly route through Circleville, east to Kelly, and back to the south again to reach Stranger Creek. The project selected to mitigate this issue is to rebuild the Circleville-Goff-Kelly 115 kV transmission lines which will bring those facilities up to the same design standards of surrounding upgraded 115 kV lines.

7.1.16 RICHMOND 115 KV SUBSTATION AND RICHMOND-ABERDEEN 115 KV



This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.
Date Exported 9/24/2020 1 inch equals 4 miles

Figure 7.16: Richmond 115 kV Substation and Richmond-Aberdeen 115 kV

In the northeast corner of South Dakota near the town of Aberdeen, two parallel 115/69 kV transformers at Ordway overload, one for the loss of the other. Cold winters drive up energy consumption in North Dakota, which will overload each of these transformers if the parallel feed is lost. The project selected to mitigate this issue is to expand the Richmond substation to accommodate a 115 kV transmission line to Aberdeen as well as a 115/69 kV transformer. This will allow some of the 69 kV load west of Ordway to have an alternate source and take loading away from the Ordway transformers. Additionally, a capacitor needs to be installed at Richmond to provide voltage support in the area.

7.1.17 BISMARCK 115 KV REACTORS

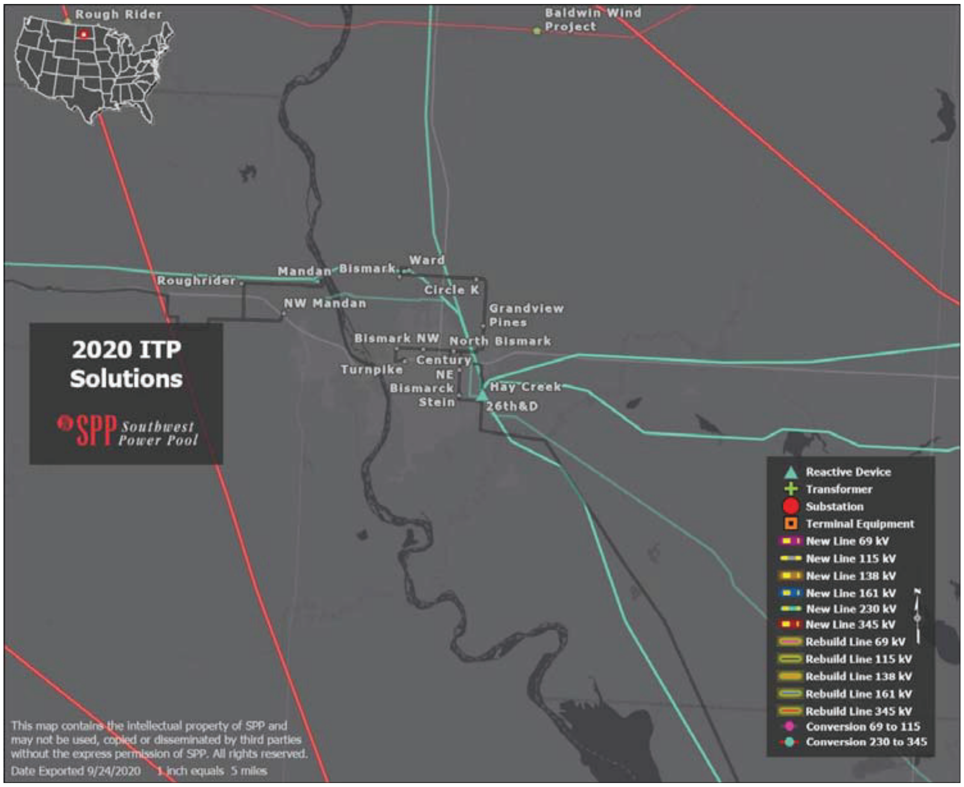


Figure 7.17: Bismarck 115 kV Reactors

Across the Missouri River from the city of Bismarck, North Dakota, light-load conditions cause base-case high voltage conditions at the Mandan 230 kV substation and surrounding 115 kV system. With limited reactive resources in the area to bring down the over-voltage condition, reactive consumption is needed near the 230 kV bus at Mandan. The project selected to mitigate this issue is to add 35 MVARs of reactive capability on two transformers at the Bismarck substation.

7.1.18 MOOREHEAD 230 KV REACTOR

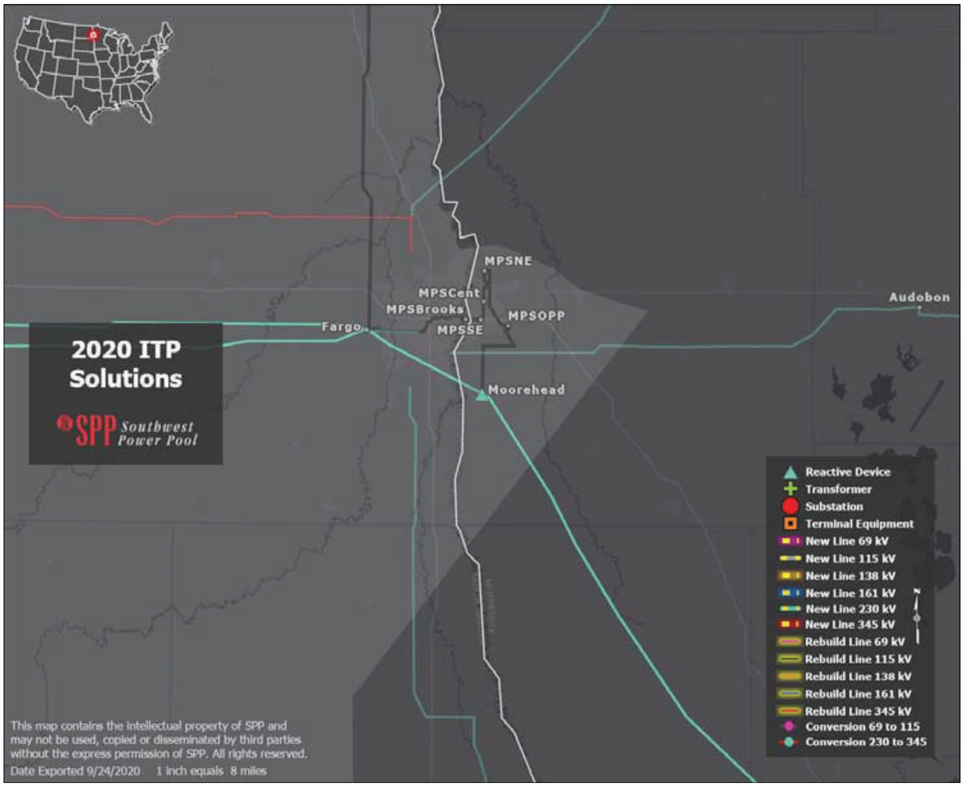


Figure 7.18: Moorehead 230 kV Reactor

Southeast of Fargo, North Dakota, across the border into Minnesota, the Moorehead 230 kV bus experiences base-case high voltage during light-load conditions and the near-term summer peak in the market powerflow models. With no reactive adjustments in the area available to help alleviate the base-case voltage issue, reactive capability must be installed to bring the voltage down to acceptable levels. Installing an 80 MVAR reactor bank at the Moorehead 230 kV bus will mitigate this issue.

7.2 SHORT-CIRCUIT PROJECTS

7.2.1 SHORT-CIRCUIT PROJECT PORTFOLIO

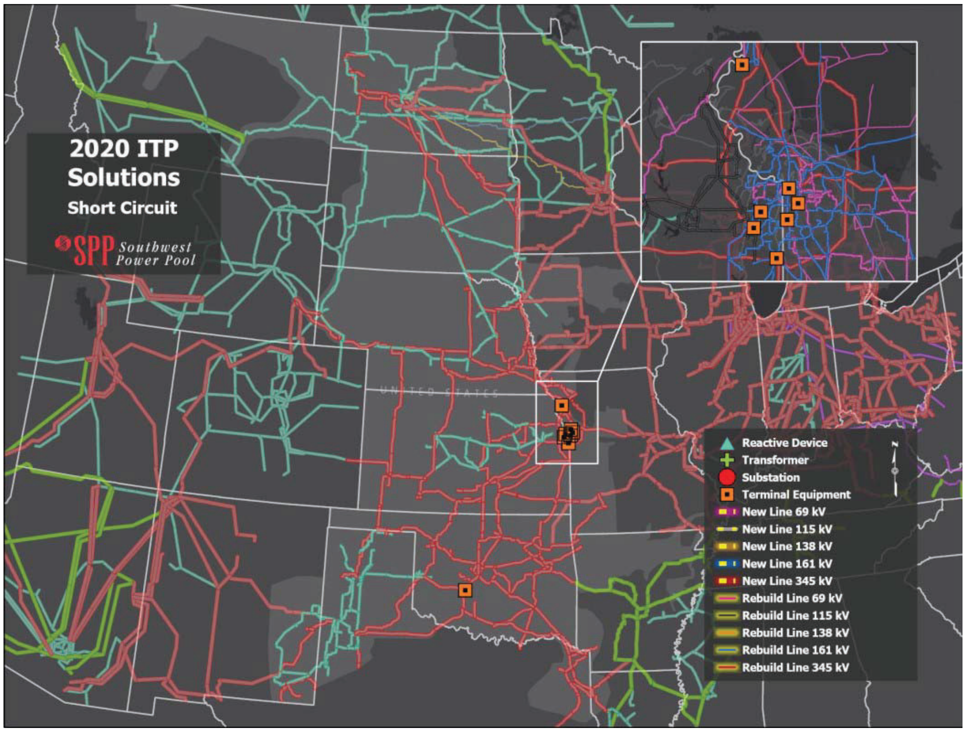


Figure 7.19: Short-Circuit Project portfolio

All short-circuit projects identified in the 2020 ITP were upgrades of overdutied breakers. These upgrades ensure SPP's members can meet short-circuit analysis requirements in the NERC TPL-001-4 standard.

Short-Circuit Project	Area	Scenario*
Replace three breakers at Northeast 161 kV	KCPL	22S / BR
Replace one breaker at Stilwell 161 kV	KCPL	22S / BR
Replace one breaker at Leeds 161 kV	KCPL	22S / BR
Replace one breaker at Shawnee Mission 161 kV	KCPL	22S / BR
Replace one breaker at Southtown 161 kV	KCPL	22S / BR
Replace two breakers at Lake Road 161 kV	KCPL	22S / BR
Replace two breakers at Craig 161 kV	KCPL	22S / BR
Replace four breakers at Anadarko 138 kV	WFEC	22S / BR

Table 7.1: Short-Circuit Projects

7.3 ECONOMIC PROJECTS

7.3.1 BUTLER-TIOGA 138 KV

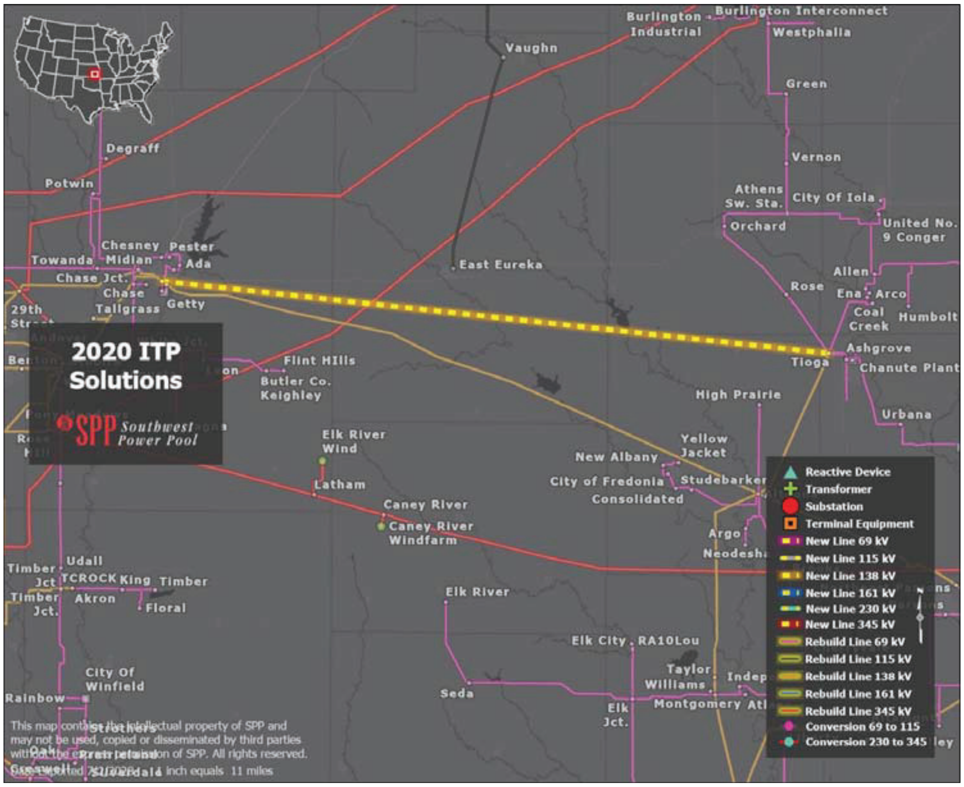
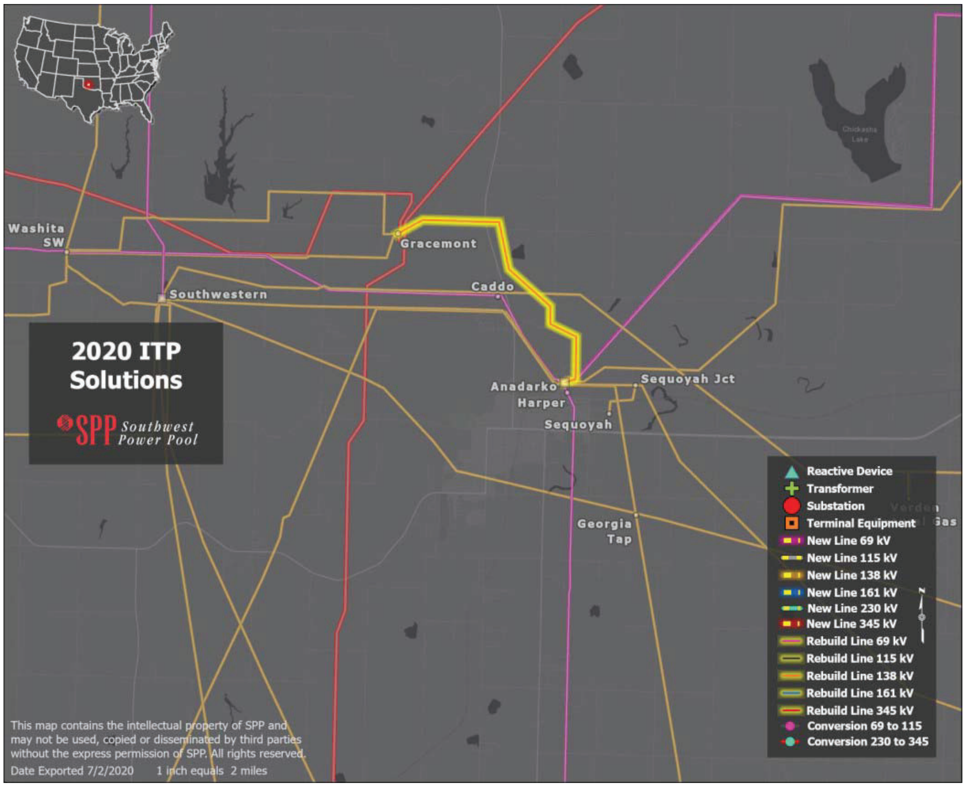


Figure 7.20: Butler-Tioga 138 kV

In southeast Kansas, the Butler-Altoona 138 kV line becomes congested for the loss of Caney River-Neosho 345 kV. The Butler-Altoona 138 kV constraint was identified as a part of Target Area 1 of the 2019 ITP assessment but was not addressed due to concerns with the final selected project, installing a phase-shifting transformer (PST) at the Butler 138 kV station. This PST project was originally selected and paired with the Wolf Creek-Blackberry 345 kV line to address residual congestion on Butler-Altoona 138 kV. Concerns were raised about the long-term viability of leaving the Butler-Altoona 138 kV in-service and installing a PST to divert system flows, primarily due to the age and condition of the facility. As discussed in the 2019 ITP, the Butler-Altoona 138 kV is known for its high outage rates during periods of high wind output or storm conditions and is nearing the level of becoming a persistent operational need for system reconfiguration, as defined in the ITP manual. The congestion in the 2020 ITP increased such that addressing the Butler-Altoona 138 kV directly was cost-beneficial to the SPP region. The preferred solution, given the benefit and the age and condition of the Butler-Altoona 138 kV line, is to wreck-out and rebuild a portion along existing right-of-way between Butler and Altoona, and re-route the termination point to Tioga, with the objective of minimizing transmission costs. This solution will provide a stronger source to an area of larger load.

7.3.2 ANADARKO-GRACEMONT 138 KV REBUILD AS DOUBLE-CIRCUIT



This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.
Date Exported 7/2/2020 1 inch equals 2 miles

Figure 7.21: Anadarko-Gracemont 138 kV Rebuild as Double-Circuit

In southwest Oklahoma, the Southwestern Station-Anadarko 138 kV line becomes congested for loss of the Anadarko-Gracemont 138 kV line. This area is impacted by west-to-east system flows and existing renewable generation on the 138 kV system. This area was analyzed as part of the 2019 ITP assessment and a project to rebuild the Anadarko-Gracemont line was selected to address congestion when the Washita-Southwestern Station line is out of service. The Anadarko-Gracemont and Washita-Southwestern Station lines form a parallel transmission path east from Washita. This area has been identified in multiple ITP assessments and currently experiences operational congestion. The initial solutions evaluated included upgrading the Southwestern Station-Anadarko line, but given that the congestion is expected to increase, further analysis was performed to determine if a modification of the existing NTC would be prudent to strengthen the area and leverage the work that will be underway. The project selected to mitigate this issue is to modify the existing NTC and rebuild the Anadarko-Gracemont 138 kV line as a double circuit. This modified solution will increase the ability of the system to facilitate west-to-east flows and protect against the single circuit contingency that causes additional congestion in real-time and for the foreseeable future.

7.3.3 RUSSETT-SOUTH BROWN 138 KV REBUILD

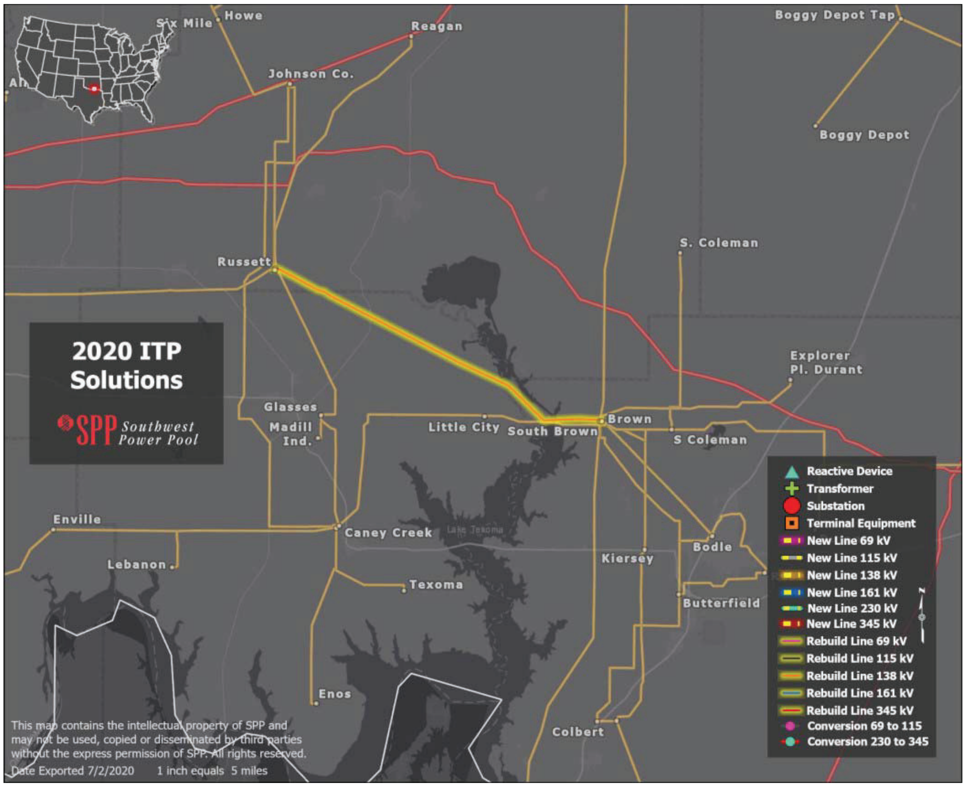


Figure 7.22: Russett-South Brown 138 kV Rebuild

In south-central Oklahoma, the Russett-South Brown 138 kV line becomes congested for the loss of the Caney Creek-Little City 138 kV line. This area is impacted by west-to-east system flows aggravated by existing and future renewable expansion. This flowgate was identified as a need in the 2019 ITP assessment but the project selected did not meet the consolidation criteria because it was identified in Future 2 and did not perform reasonably well in Future 1. With increasing bulk transfers in the area evaluated in the 2020 ITP assessment, congestion increased in both futures and a project became cost-beneficial to the region. The project selected to address the congestion is a rebuild of the Russett-South Brown 138 kV line, consistent with the top solution analyzed in the 2019 ITP.

7.3.4 GRDA 345/161 KV TRANSFORMERS

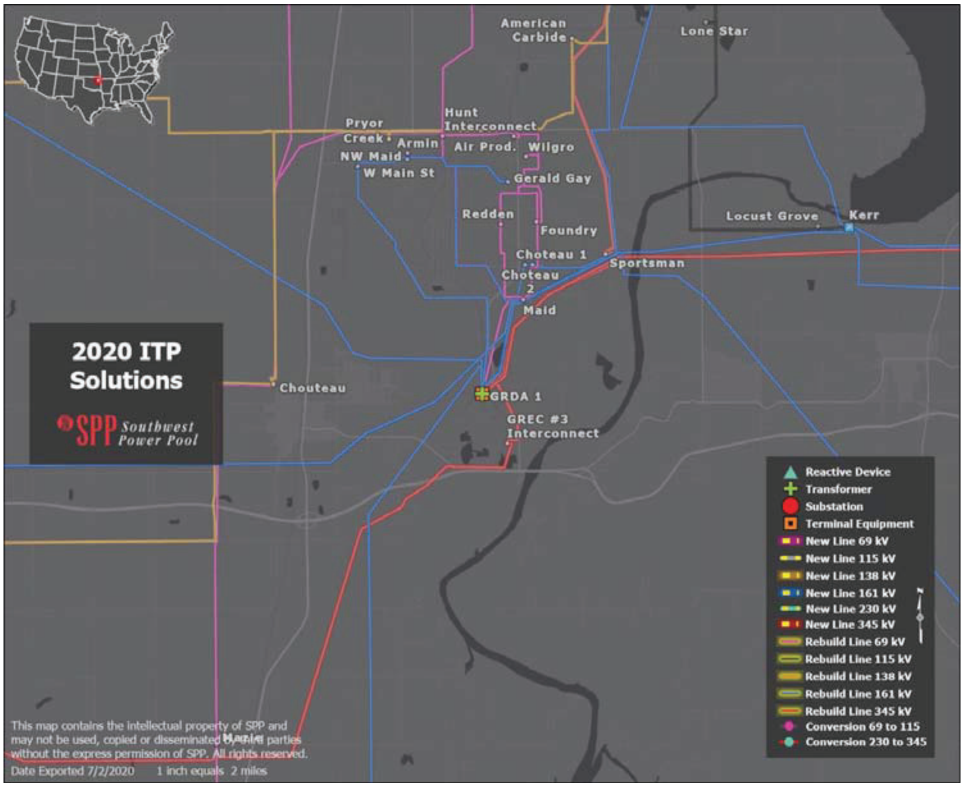


Figure 7.23: GRDA 345/161 kV Transformers

East of Tulsa, Oklahoma, at the GRDA plant substation, the second GRDA 345/161 kV transformer becomes congested for the loss of the first transformer. Both transformers are rated equally and are terminally limited, driving the need for the selected project to upgrade terminal equipment to increase the capacity of both transformers.

7.3.5 COLUMBUS EAST 230/115 KV TRANSFORMER

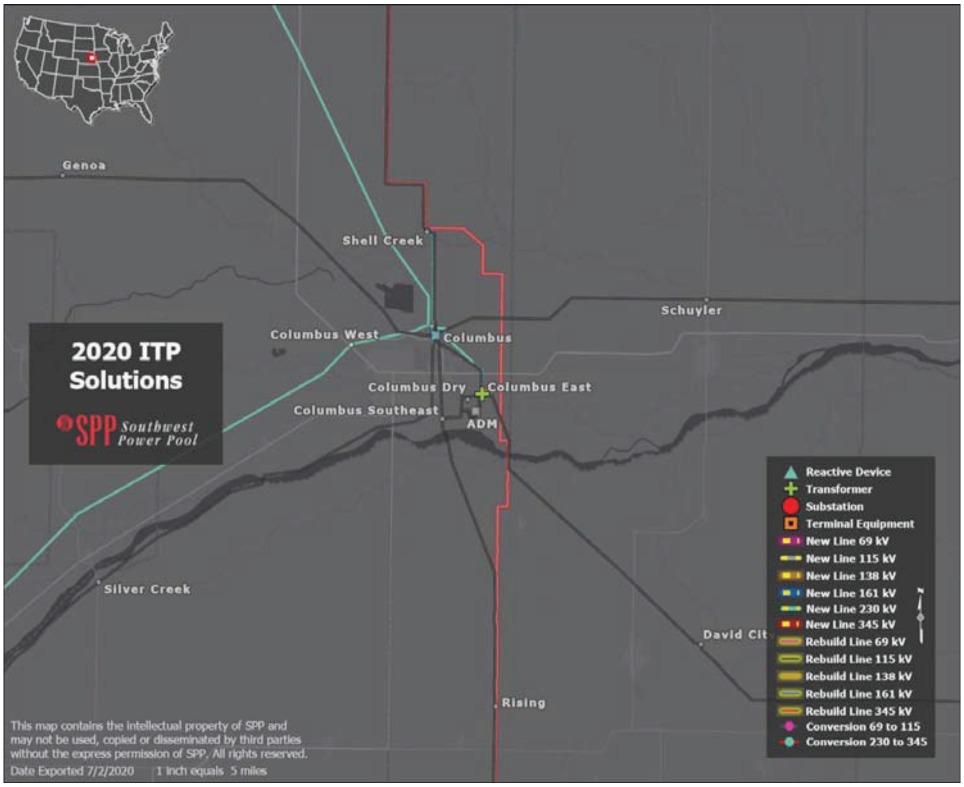


Figure 7.24: Columbus East 230/115 kV Transformer

Northwest of Omaha and Lincoln, Nebraska, the Columbus East 230/115 kV transformer becomes congested for the loss of the Columbus East-Shell Creek 345 kV line. This area experiences north-to-south system flows that are diverted with the loss of the 345 kV connection and has seen system congestion in real-time operations today. The project selected to address the congestion is to replace the Columbus East transformer in order to better utilize the HV system that feeds into Columbus, Lincoln, and Omaha, NE load centers.

7.3.6 FRANKS-SOUTH CROCKER-LEBANON 161 KV

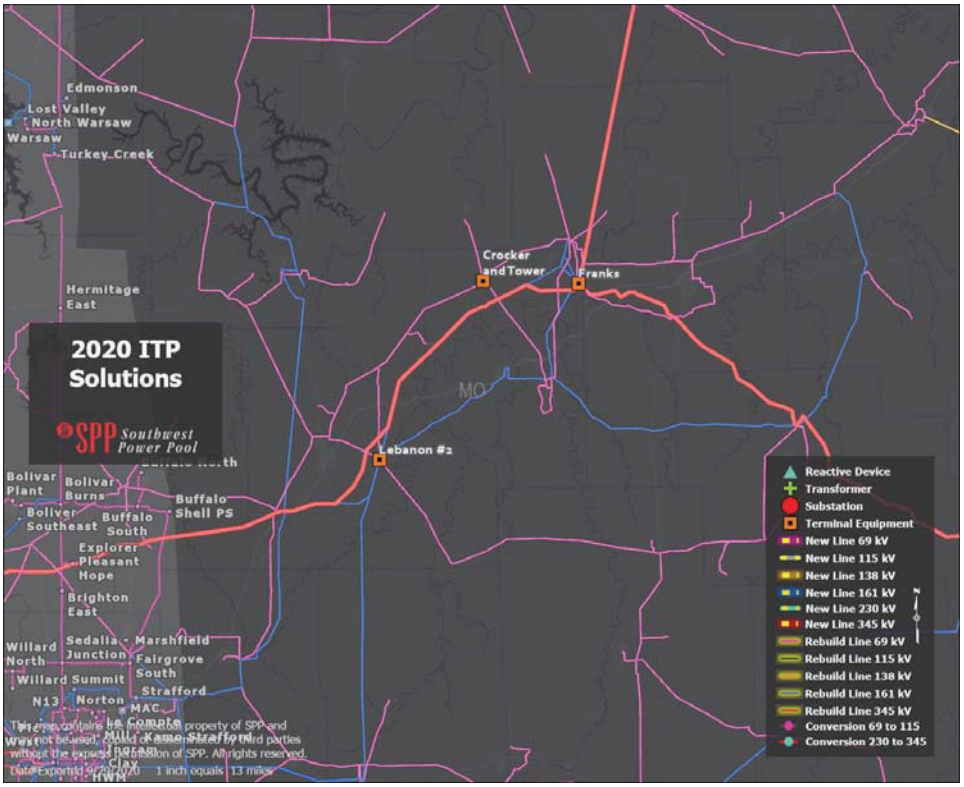


Figure 7.25: Franks-South Crocker-Lebanon 161 kV

In south-central Missouri, northeast of Springfield, the Franks-Crocker 161 kV line becomes congested for the loss of the Huben-Franks 345 kV line. The 161 kV path parallels the 345 kV path and carries the power when the EHV line is out of service. The 161 kV path is terminally limited so upgrading the terminal equipment at the Franks, South Crocker, and Lebanon substations relieves the congestion by allowing for increased flows in the area.

7.3.7 CHISHOLM-WOODWARD/BORDER TAP 345 KV

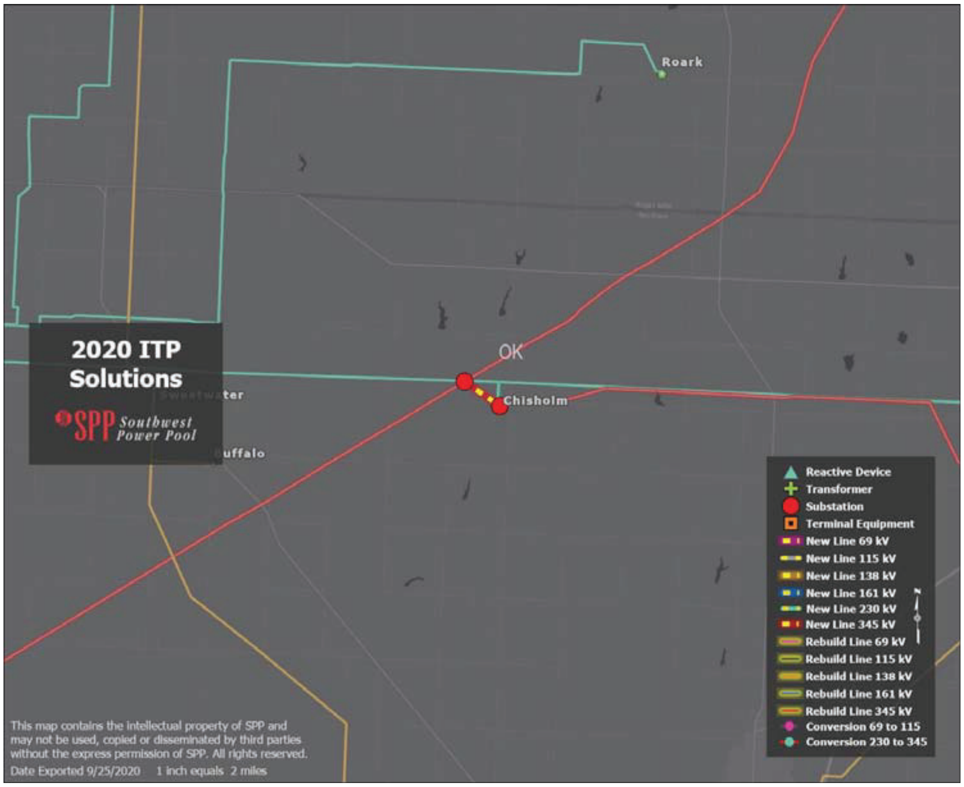


Figure 7.26: Chisholm-Woodward/Border Tap 345 kV

In western Oklahoma, just east of the Texas border, the 345 kV system out of Gracemont to the west is built out but not connected. The top congested flowgate in the area is the Shamrock 115/69 kV transformer for the loss of the Sweetwater-Chisholm 230 kV line. The project selected for the area is to tap the Border-Tuco 345 kV line and connect to the Chisholm 345 kV station less than a mile away. This project connects the 345 kV radial from Gracemont to the rest of the 345 kV system and allows more bulk transfers across the east Texas/west Oklahoma system. The Sweetwater-Chisholm outage has also been identified as a limiting constraint in the assessment of resource adequacy.

7.3.8 DOVER SWITCH-OKEENE AND ASPEN-MOORELAND-PIC 138 KV

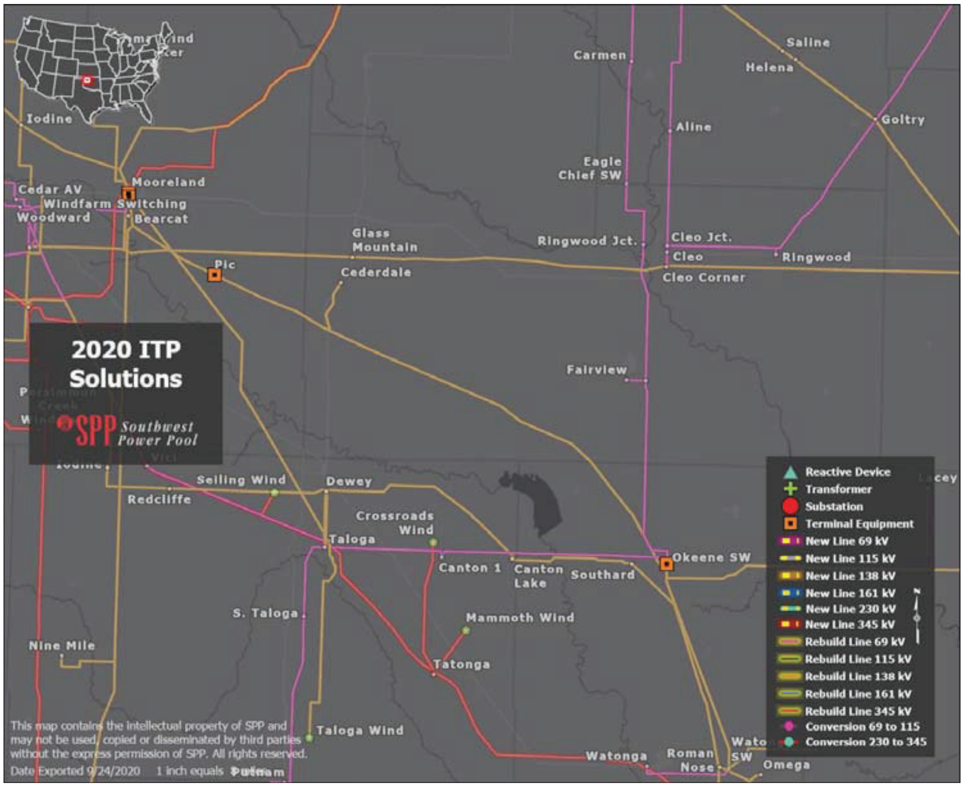


Figure 7.27: Dover Switch-Okeene and Aspen-Mooreland-Pic 138 kV

Northwest of Oklahoma City towards Woodward, the Dover-Okeene 138 kV line becomes congested for the loss of the Watonga-Okeene 138 kV line. The line to Watonga is a parallel 138 kV path to the south while the line to Dover is to the east out of the Okeene substation. This 138 kV network supports west-to-east bulk power transfers to bring low cost generation to the central and eastern load centers. The Dover-Okeene line is terminally limited, and when those limitations are eliminated, congestion increases on the 138 kV system to the north. The project selected to address the congestion is to upgrade terminal equipment on the Dover Switch-Okeene 138 kV line. To realize the benefits of increased transfers on the Dover-Okeene line, terminal equipment on the upstream elements of Aspen-Mooreland-Pic 138 kV must also be upgraded.

7.3.9 MINCO-PLEASANT VALLEY-DRAPER 345 KV

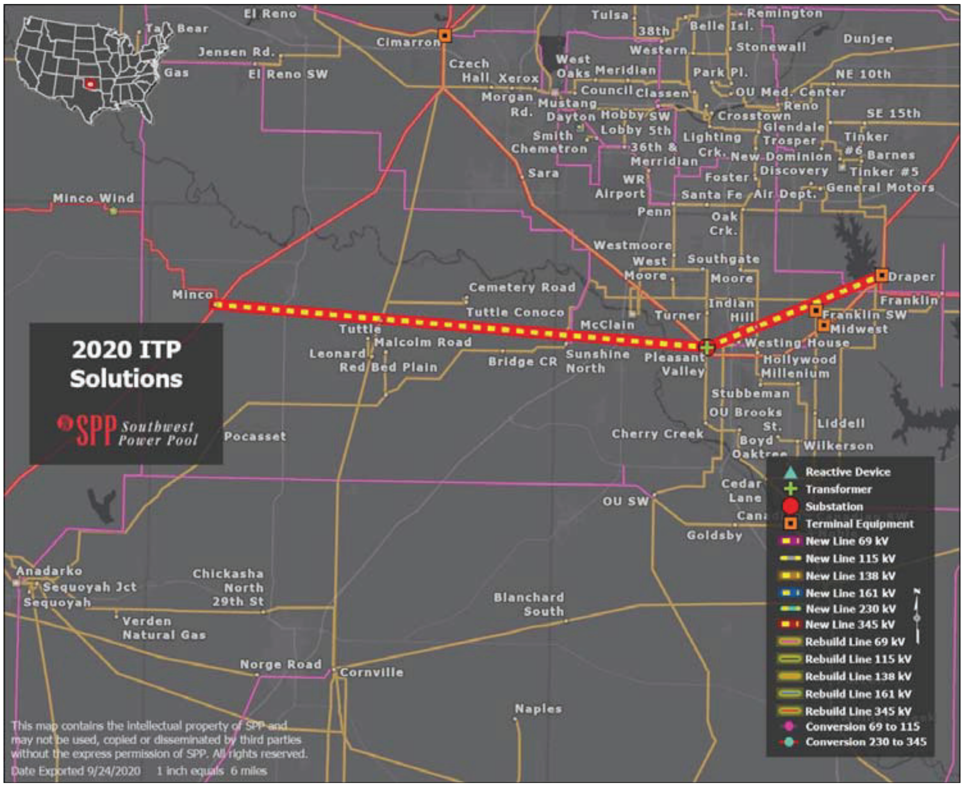


Figure 7.28: Minco-Pleasant Valley-Draper 345 kV

Several different needs were identified in and around the Oklahoma City (OKC) area. The first of two 345/138 kV transformers at Cimarron experiences congestion for the loss of the second. Just south of the Cimarron station, the Czech Hall-Cimarron 138 kV line, which feeds the west side of the city, experiences congestion for the loss of the Cimarron-Draper 345 kV line. The Skyline-Quail Creek 138 kV line to the north of the city experiences congestion for the loss of the Northwest-Arcadia 345 kV line. These issues show the impact of west-to-east power flows across the EHV loop around OKC as well as the need for additional sources into OKC to serve local load.

Multiple solutions to address congestion in the area were analyzed, from new EHV on both the north and south sides of OKC, to HV solutions attempting to address the congestion directly. The project selected is:

- A new Minco-Pleasant Valley-Draper 345 kV line on the south side of OKC;
- A tie-in of the existing Cimarron-Draper 345 kV line to the Pleasant Valley substation;
- Terminal upgrades at Cimarron and Draper to increase the line rating to a 3.000 amp standard that the new facilities will be built at; and
- Terminal upgrades on the Midwest-Franklin 138 kV line to address downstream congestion on the HV system that exists today.

7.3.10 SPLIT ROCK 345/115 KV TRANSFORMERS

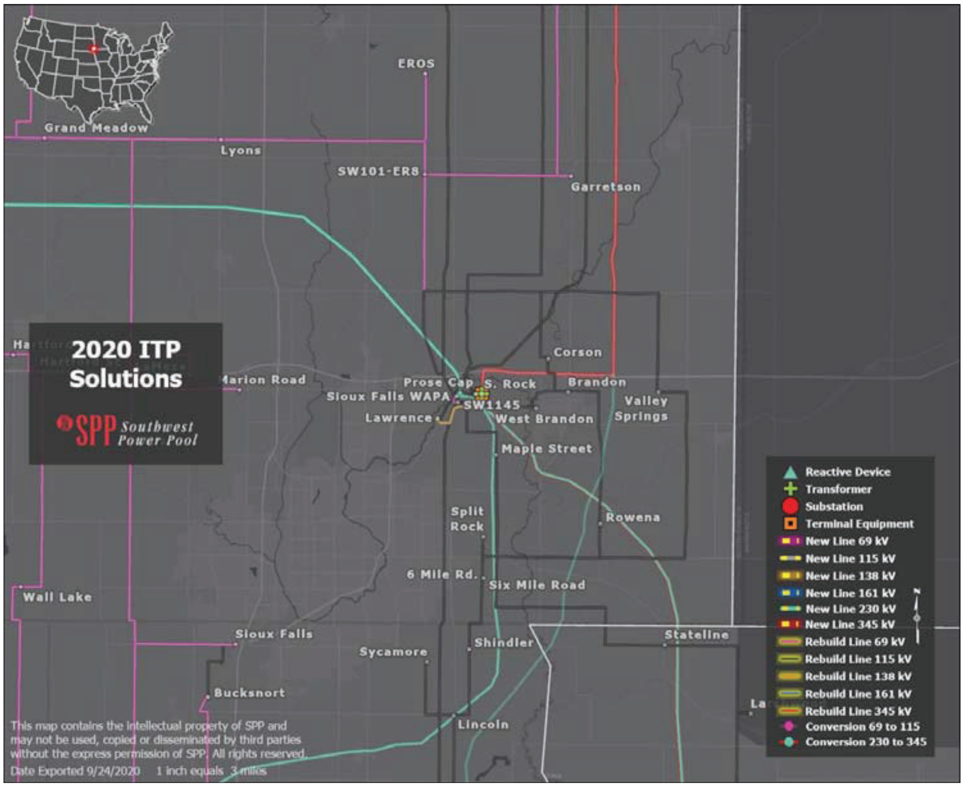


Figure 7.29: Split Rock 345/115 kV Transformers

On the northeast side of Sioux Falls, South Dakota, the Split Rock substation helps to serve as a transmission hub for power transfers, mostly in support of north-to-south flows. The first Split Rock 345/115 kV transformer becomes congested for the loss of the second. This issue was also analyzed in the CSP study with MISO but did not produce a solution beneficial to both regions because SPP generation is largely redispatching to resolve the congestion. These transformers are terminally limited and by upgrading this equipment, the SPP region still sees benefit even though this facility is not under the SPP tariff, but rather a Northern States Power facility in MISO. The selected solution is to upgrade terminal equipment on both Split Rock 345/115 kV transformers.

An upgrade of a Non-SPP facility in MISO would require additional coordination with Northern States Power (NSPP) and MISO, and a FERC filing to support SPP regional highway/byway cost allocation. The project benefits are primarily driven by Future 2 and marginally passed consolidation by including a small amount of real-time operational congestion. Additionally, there are stakeholder concerns around the benefits and staff concerns that the upgrade may reflect the need for a generator outlet facility for a MISO-projected resource and siting plan assumed in Future 2.

For these reasons, there is not strong enough justification for SPP to pursue this upgrade at this time and is recommending to defer addressing this system limit to future ITP/CSP cycles.

7.3.11 OAHE-SULLY BUTTES-WHITLOCK 230 KV

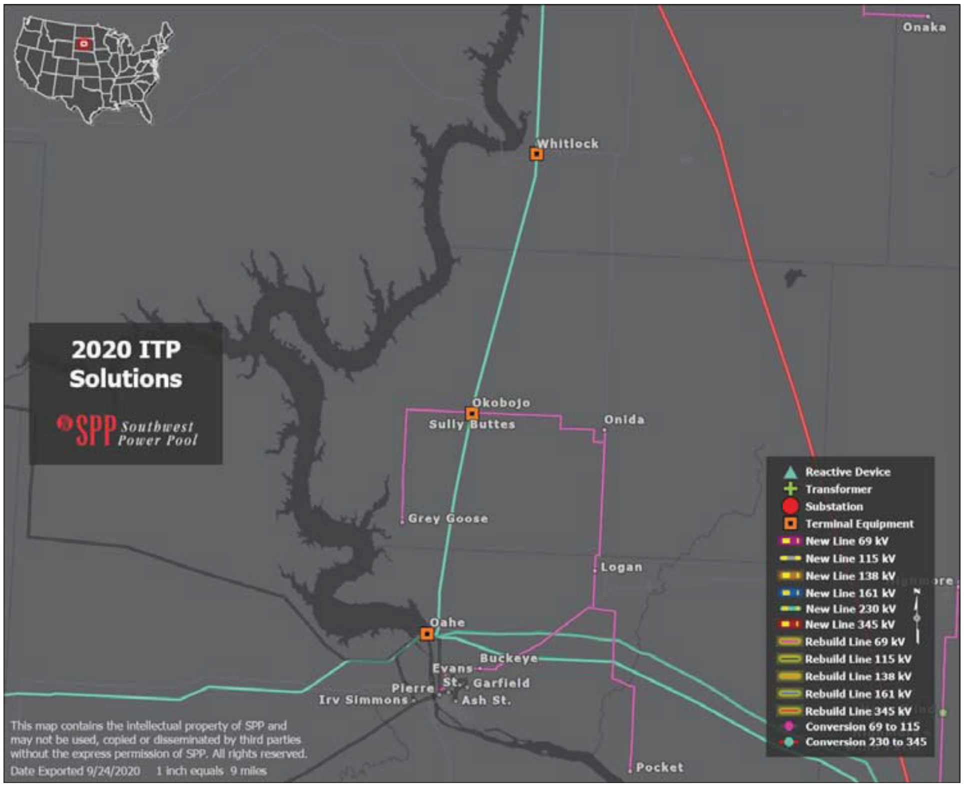
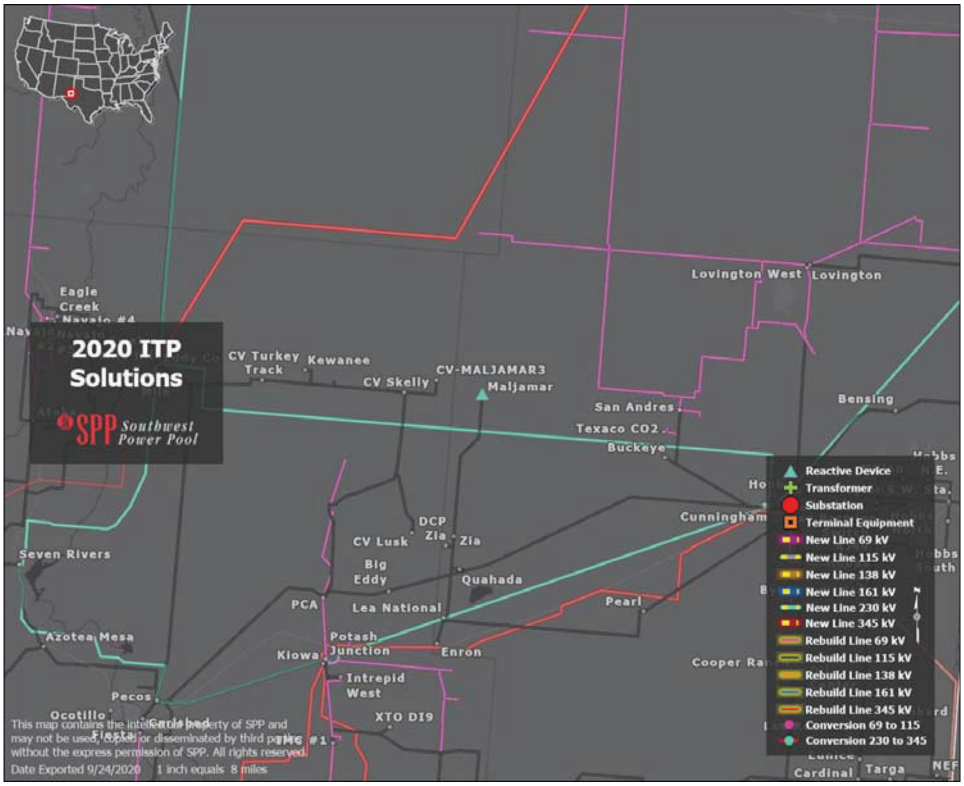


Figure 7.30: Oahe-Sully Buttes-Whitlock 230 kV

To the north of Pierre, South Dakota, multiple transmission paths help to serve load centers to the north towards Bismarck, North Dakota. The Oahe-Sully Buttes 230 kV line becomes congested for the loss of the Fort Thompson-Leland Olds 345 kV line. The 230 kV segments from Oahe moving north are all terminally limited. Solutions were tested to determine the number of segments that would need to be upgraded to relieve congestion in a cost-beneficial manner on the full 230 kV path to the north. The optimal solution was to replace terminal equipment and increase line clearances for the Oahe-Sully Buttes-Whitlock 230 kV lines.

However, estimated cost did not include additional expenses for transmission line clearance mitigations which, when considered, do not make this project cost beneficial enough to receive an NTC at this time. SPP recommends that this project be reconsidered in future ITP cycles.

7.3.12 MALJAMAR 115 KV CAPACITOR BANK



This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.

Date Exported 9/24/2020 1 inch equals 8 miles

Figure 7.31: Maljamar 115 kV Capacitor Bank

West of Hobbs near the community of Maljamar, New Mexico, the Maljamar 115 kV bus experiences both base-case low voltage and low voltage for the loss of the PCA-Big Eddy 115 kV line. These low voltages are present only in the long-term summer peaks of the market powerflow models. The Maljamar bus serves load at the end of a radial feed, making it susceptible to lower voltages. The PCA-Big Eddy 115 kV line is a connector to the 230 kV bus at Potash Junction, which causes the Maljamar 115 kV bus to lose voltage support once the contingency occurs. Adding a capacitor capable of producing 14.4 MVAR at the Maljamar 115 kV bus will mitigate this issue.

7.3.13 RUSSELL 115 KV CAPACITOR BANK

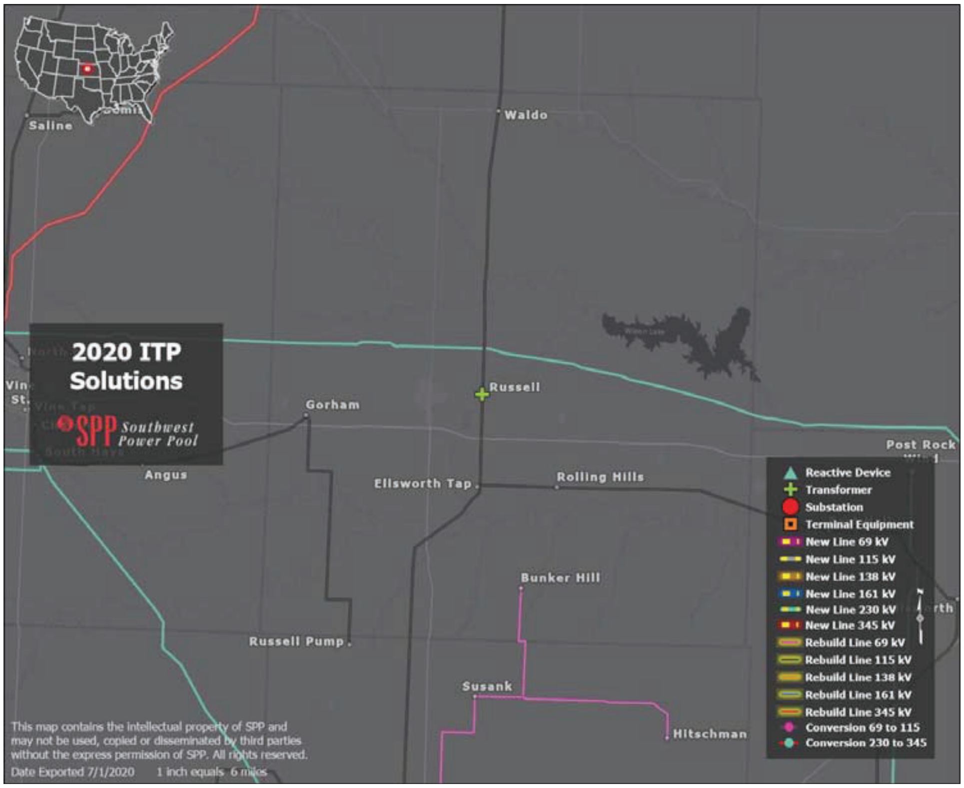


Figure 7.32: Russell 115 kV Capacitor Bank

West of Salina near the town of Russell, Kansas, the Russell substation experiences low voltage for the loss of the Ellsworth Tap-Russell 115 kV transmission line. Upon contingency, the Russell load is fed at the end of a long radial 115 kV line, which causes voltage drop below criteria when load is high in the summer in the market powerflow models. The project selected to mitigate this issue is to add a 24 MVAR capacitor at the Russell substation to bring the voltage back up to acceptable levels.

7.3.14 AGATE 115 KV REACTOR

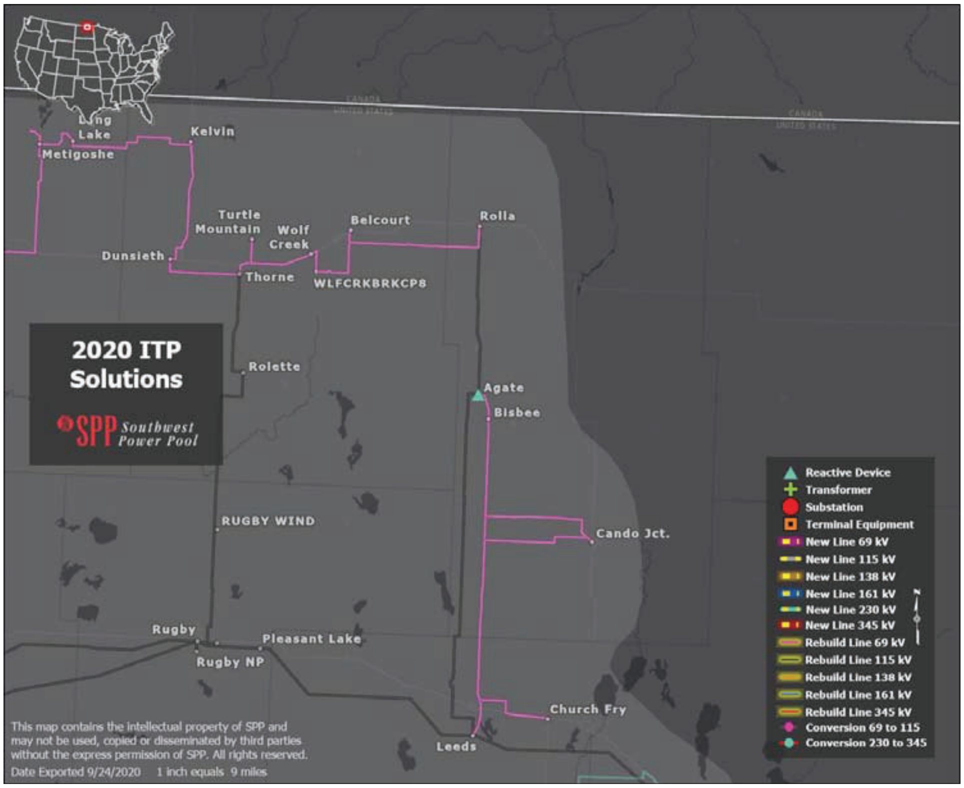


Figure 7.33: Agate 138 kV Reactor

Northwest of Grand Forks, near the town of Rolla, North Dakota, light-load conditions in the market powerflow models cause the 69 kV system to experience base-case high voltages coming off the 115/69 kV transformers at Agate and Leeds. Tap adjustments on the Agate 115/69 kV transformer shift the over-voltage to the high side of the transformer, making this an infeasible mitigation. With no other reactive resources in the area to bring down the over-voltage condition, reactive consumption needs to be installed near the 69 kV loads in this region. The project selected to mitigate this issue is to add a 12 MVAR reactor at the Agate 115 kV bus.

7.3.15 DEVIL'S LAKE 115 KV REACTOR

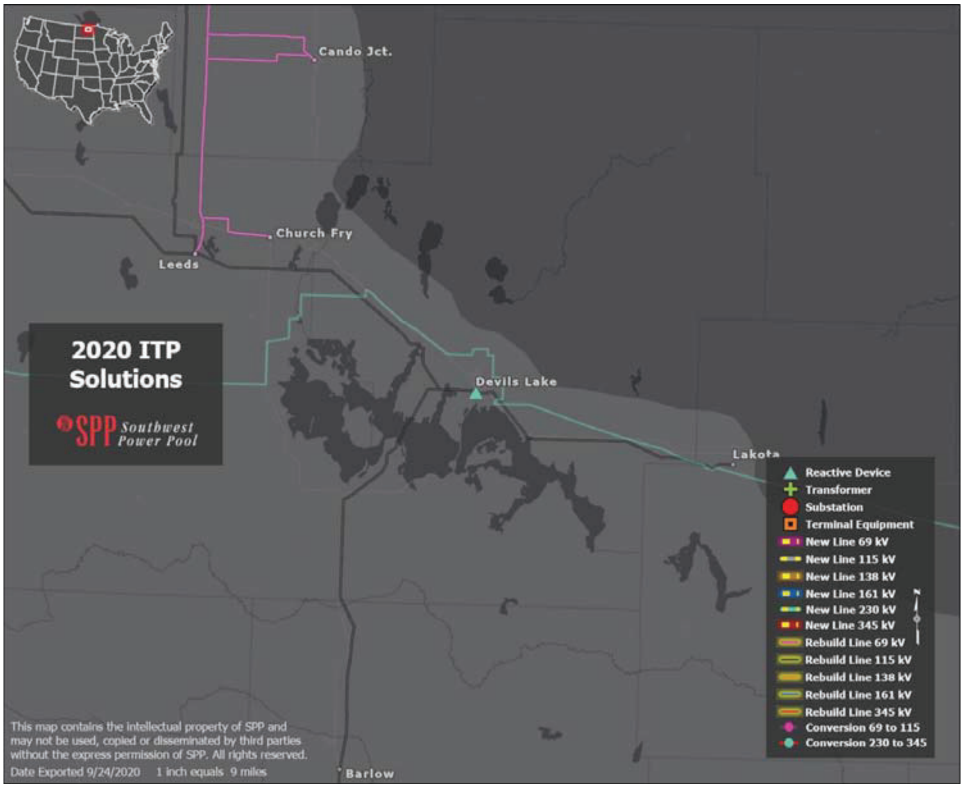


Figure 7.34: Devil's Lake 115 kV Reactor

West of Grand Forks, near the town of Devil's Lake, North Dakota, the 115 kV bus at Devil's Lake and surrounding area experiences high base-case voltages during light-load conditions in the market powerflow models. Without any reactive consumption devices or tap changing transformers nearby, no reactive adjustments are available to bring the voltage back to acceptable levels. The project selected to mitigate this issue is to install a 25 MVAR capable reactor bank at the Devil's Lake 115 kV substation.

7.4 POLICY PROJECTS

No policy projects are required for the 2020 ITP assessment.

8 INFORMATIONAL PORTFOLIO ANALYSIS

8.1 BENEFITS

8.1.1 METHODOLOGY

Benefit metrics were used to measure the value and economic impacts of the final portfolio. The Benefit Metrics Manual[27] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed that the 2020 ITP B/C ratios be calculated for the final portfolio using the Future 1 and Future 2 models. The benefit analysis is performed on all reliability and economic projects in the final portfolio shown in Table 9.1 (regardless of NTC recommendation). The benefit structure shown in Table 8.1 illustrates the metrics calculated as the incremental benefit of the projects included in the portfolios.

Metric Description
APC Savings
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emissions Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 8.1: Benefit Metrics

8.1.2 APC SAVINGS

APC captures the monetary cost associated with fuel prices, run times, grid congestion, unit operating costs, energy purchases, energy sales and other factors that directly relate to energy production by generating resources in the SPP footprint. Additional transmission projects aim to relieve system congestion and reduce

---

[27] Benefit Metrics Manual

costs through a combination of a more economical generation dispatch, more economical purchases and optimal revenue from sales.

To calculate benefits over the expected 40-year life of the projects[28], two years were analyzed, 2025 and 2030. APC savings were calculated accordingly for these years. The benefits are extrapolated to the fifteenth year based on the slope between the two points. After that, they are assumed to grow at an inflation rate of 2.5 percent per year. Each year's benefit was then discounted to 2025 using an eight percent discount rate, and a 2.5 percent inflation rate from 2025 back to 2020. The sum of all discounted benefits was presented as the NPV benefit. This calculation was performed for every zone.

Figure 8.1 shows the regional APC savings for the recommended portfolio over 40 years.

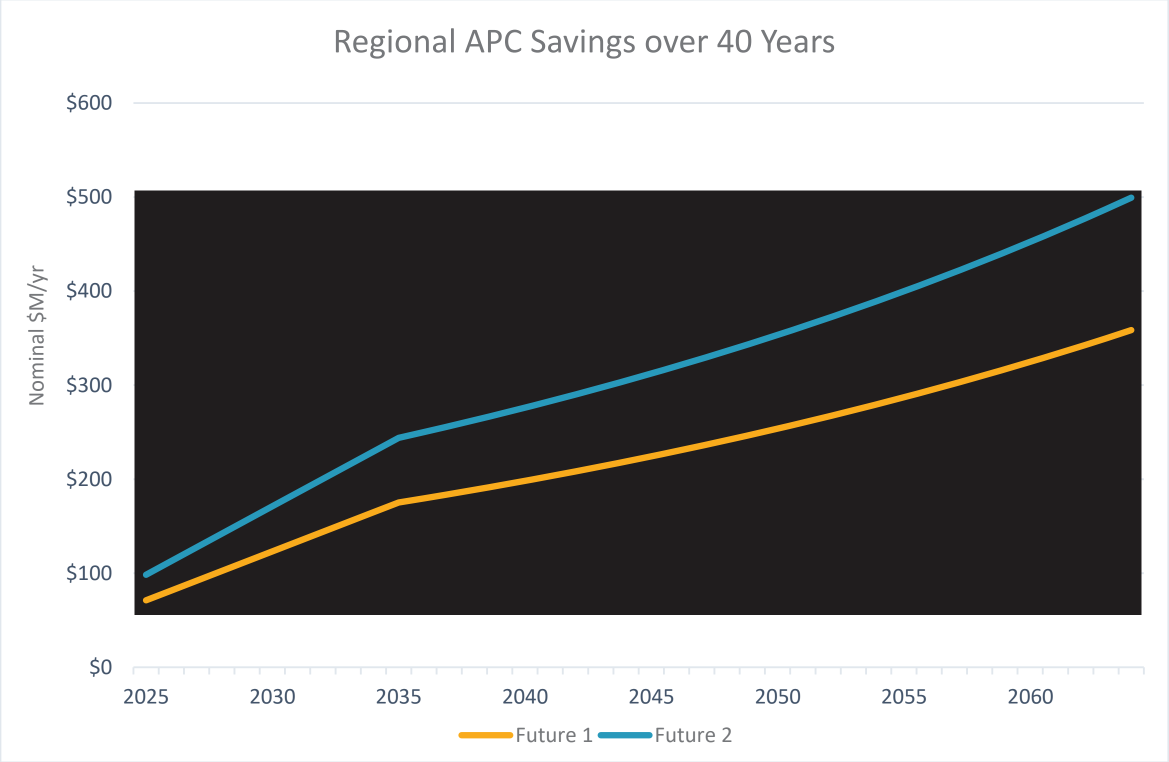


Figure 8.1: Regional APC Savings for the 40-Year Study Period

Table 8.2 provides the zonal breakdown and the NPV estimates. Future 2 has higher congestion compared to Future 1. Therefore, the projects in the recommended portfolio provide more congestion relief in Future 2 than in Future 1, resulting in larger APC savings.

---

[28] The SPP OATT requires that the portfolio be evaluated using a 40-year financial analysis.

Zone	Reference Case (Future 1)			Emerging Technologies (Future 2)		
	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)
AEPW	$9.2	$22.4	$350.0	$15.9	$37.7	$587.8
EMDE	$5.2	$3.7	$39.4	$8.3	$5.1	$50.2
GMO	$0.2	$1.2	$20.5	$1.8	$3.7	$56.7
GRDA	$8.7	$12.9	$186.3	$6.9	$10.5	$152.3
KCBPU	($0.1)	$0.6	$11.5	$0.0	$2.1	$37.5
KCPL	$1.9	$3.8	$57.2	($0.3)	$1.6	$30.4
LES	$0.2	$0.3	$4.2	$0.3	$1.6	$26.2
MIDW	($1.1)	($1.5)	($20.7)	($1.2)	($1.3)	($16.8)
NPPD	$0.2	$0.7	$12.1	($0.1)	$0.9	$16.8
OKGE	$31.4	$57.0	$854.4	$33.5	$64.7	$979.5
OPPD	$0.3	($0.4)	($8.0)	$0.8	$1.4	$21.0
SPRM	$1.1	$0.7	$5.9	$1.1	$0.4	$2.0
SPS	($0.4)	($0.1)	$0.7	$9.4	$2.0	($11.7)
SUNC	($3.5)	($4.8)	($67.1)	($3.4)	($3.9)	($52.2)
SWPA	$0.3	$0.7	$11.6	$1.6	$2.4	$34.2
UMZ	$5.8	$9.2	$134.1	$9.6	$23.1	$361.1
WERE	$4.6	$6.0	$83.1	$4.7	$4.6	$58.3
WFEC	$7.0	$11.3	$165.4	$9.3	$16.6	$248.0
TOTAL:	**$71.2**	**$123.8**	**$1,840.4**	**$98.4**	**$173.3**	**$2,581.3**

Table 8.2: APC Savings by Zone

Table 8.3 provides the zonal breakdown and the NPV estimates for the SPP "other" zone. This zone includes merchant generation (without contractual arrangements with load-serving entities) and additional renewable resource plan wind resources. The calculation for this zone is 100 percent production cost minus sales to other zones (revenue).

Zone	Reference Case (F1)			Emerging Technologies (F2)		
	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)	2025 ($M)	2030 ($M)	40-yr NPV ($2020M)
OTHSPP	$38.8	$85.3	$1,317.2	$54.8	$69.6	$960.9

Table 8.3: Other SPP APC Benefit

8.1.3 REDUCTION OF EMISSION RATES AND VALUES

Additional transmission may result in a lower fossil-fuel burn (for example, less coal-intensive generation), resulting in less SO2, NOX, and CO2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. Note that neither ITP future assumes any allowance prices for CO2.

8.1.4 SAVINGS DUE TO LOWER ANCILLARY SERVICE NEEDS AND PRODUCTION COSTS

Ancillary services, such as spinning reserves, ramping (up/down), regulation, and 10-minute quick start are essential for the reliable operation of the electrical system. Additional transmission can decrease the ancillary services costs by: (a) reducing the ancillary services quantity needed, or (b) reducing the procurement costs for that quantity.

The ancillary services needs in SPP are determined according to SPP's market protocols and do not change based on transmission. Therefore, the savings associated with the "quantity" effect are assumed to be zero.

The costs of providing ancillary services are captured in the APC metric. The production cost simulations set aside fixed levels of resources to provide regulation and spinning reserves. As a result, the benefits related to "procurement cost" effect are already included as a part of the APC savings presented in this report.

8.1.5 AVOIDED OR DELAYED RELIABILITY PROJECTS

Potential reliability needs are reviewed to determine if the upgrades proposed for economic or policy reasons defer or replace any reliability upgrades. The avoided or delayed reliability project benefit represents the costs associated with these additional reliability upgrades that would otherwise have to be pursued.

To calculate the avoided or delayed reliability projects benefit for the recommended portfolio, the ability for economic projects to avoid or delay a base reliability project is analyzed and identified in the optimization milestone. No overlap was identified; therefore, no avoided or delayed reliability projects were identified, and the associated benefits are estimated to be zero.

8.1.6 CAPACITY COST SAVINGS DUE TO REDUCED ON-PEAK TRANSMISSION LOSSES

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. Transmission projects often reduce losses during peak load conditions, which lowers the costs associated with additional generation capacity needed to meet the capacity requirements.

The capacity cost savings for the recommended portfolio are calculated based on the on-peak losses estimated in the base reliability powerflow model. The loss reductions are then multiplied by 112 percent to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (CONE) of $85.61/kW-yr in 2018 dollars. The net CONE value was obtained from Attachment AA Resource Adequacy-Attachment AA Section 14 of the tariff. The net CONE was assumed to grow at an inflation rate of 2.5 percent for each study year, $2M for 2025, and $2.7M for 2030. Table 8.4 displays the associated capacity savings for each zone in each study year and the 40-year NPV.

Base Reliability			
Zone	**2025 ($M)**	**2030 ($M)**	**40-yr NPV (2020$M)**
AEPW	$0.08	$0.11	$1.46
EMDE	($0.00)	($0.00)	($0.01)
GMO	$0.00	$0.00	$0.04
GRDA	$0.00	$0.00	$0.01
KCBPU	$0.00	$0.00	($0.00)
KCPL	$0.01	$0.00	$0.03
LES	$0.00	$0.00	$0.03
MIDW	$0.00	$0.00	$0.02
NPPD	$0.02	$0.01	$0.08
OKGE	$0.38	$0.47	$6.46
OPPD	($0.00)	($0.00)	($0.01)
SPRM	($0.00)	($0.00)	($0.00)
SPS	$0.73	$1.20	$17.63
SUNC	$0.01	$0.01	$0.10
SWPA	$0.04	$0.04	$0.50
UMZ	$0.38	$0.52	$7.42
WFEC	$0.11	$0.11	$1.36
WERE	$0.22	$0.25	$3.36
Total:	**$2.0**	**$2.7**	**$38.5**

Table 8.4: On-Peak Loss Reduction and Associated Capacity Cost Savings

8.1.7 ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

This metric monetizes the benefits of reliability projects built to meet compliance requirements and mitigate SPP Criteria violations. The regional benefits are assumed to be equal to the 40-year NPV of ATRRs of the projects, totaling $217 million in 2020 dollars.

The system reconfiguration (SR) approach to allocate zonal benefits utilizes the powerflow models to measure incremental flows shifted onto the existing system during an outage of the proposed reliability upgrade. This is used as a proxy for how much each upgrade reduces flows on the existing transmission facilities in each zone. Results from the production cost simulations are used to determine hourly flow direction on the upgrades and applied as weighting factors for the powerflow results.

Table 8.5 summarize the SR analysis results, load-ratio shares (LRS), and the benefit allocation factors for different voltage levels. The table shows the overall zonal benefits calculated by applying these allocation factors.

Mandated Reliability Benefits Base Reliability and Short-Circuit									
	< 100 kV	100-300 kV			> 300 kV			All Projects	
SPP-wide Benefit	**$22.86**	**$130**			**$64**			**$217**	
Zone	**100% SR**	**67% SR**	**33% LRS**	**Wtd. Avg**	**33% SR**	**67% LRS**	**Wtd. Avg**	**Allocation**	**Benefit 2020$M**
AEPW	6.8%	10.4%	20.3%	13.7%	0.5%	20.3%	13.7%	13.0%	$28.1
EMDE	3.2%	1.5%	2.3%	1.8%	0.6%	2.3%	1.7%	1.9%	$4.2
GMO	2.9%	7.2%	3.7%	6.1%	24.9%	3.7%	10.8%	7.1%	$15.5
GRDA	1.1%	0.6%	1.6%	1.0%	0.4%	1.6%	1.2%	1.1%	$2.3
KCBPU	0.1%	1.9%	0.9%	1.5%	0.2%	0.9%	0.7%	1.1%	$2.5
KCPL	4.5%	7.0%	7.4%	7.2%	20.5%	7.4%	11.8%	8.2%	$17.9
LES	0.3%	0.2%	1.4%	0.6%	17.0%	1.4%	6.6%	2.4%	$5.1
MIDW	4.9%	2.8%	0.7%	2.1%	0.3%	0.7%	0.6%	2.0%	$4.3
NPPD	6.9%	4.0%	6.0%	4.7%	7.4%	6.0%	6.5%	5.4%	$11.8
OKGE	17.3%	13.0%	12.9%	13.0%	1.3%	12.9%	9.1%	12.3%	$26.7
OPPD	4.0%	2.5%	4.6%	3.2%	0.4%	4.6%	3.2%	3.3%	$7.1
SPRM	4.6%	3.2%	2.1%	2.9%	0.0%	2.1%	1.4%	2.6%	$5.7
SPS	3.2%	2.8%	0.7%	2.1%	0.3%	0.7%	0.6%	1.8%	$3.9
SUNC	7.3%	1.2%	1.3%	1.3%	0.3%	1.3%	1.0%	1.8%	$3.9
SWPA	23.2%	29.3%	11.4%	23.3%	23.0%	11.4%	15.3%	20.9%	$45.4
UMZ	4.4%	2.7%	9.4%	4.9%	0.0%	9.4%	6.3%	5.3%	$11.5
WERE	3.5%	5.3%	9.8%	6.8%	2.9%	9.8%	7.5%	6.7%	$14.5
WFEC	1.7%	4.1%	3.2%	3.8%	0.2%	3.2%	2.2%	3.1%	$6.8
Total:	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**$216.9**

Table 8.5: Mandated Reliability Benefits

8.1.8 BENEFIT FROM MEETING PUBLIC POLICY GOALS

This metric represents the economic benefit provided by the transmission upgrades for facilitating public policy goals. In this study, the scope is limited to meeting public policy goals related to renewable energy. System-wide benefits are assumed to be equal to the cost of policy projects.

Since no policy projects were identified as a part of the recommended portfolio, the associated benefits are assumed to be zero.

8.1.9 MITIGATION OF TRANSMISSION OUTAGE COSTS

The standard production cost simulations used to estimate APC savings assume that transmission lines and facilities are available during all hours of the year, ignoring the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission outage costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort needed to develop these augmented models for each case, the findings from the RCAR II study were used to calculate this benefit metric for the consolidated portfolio as a part of this ITP assessment.

In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 11.3 percent.[29] Applying this ratio to the APC savings estimated for the recommended portfolio translates to a 40-year NPV benefit of $1,840 million for Future 1 and $2,581 million for Future 2 in 2020 dollars. These benefits are allocated to zones based upon their LRS within the region. Table 8.6 shows the outage mitigation benefits allocated to each SPP zone.

Zone	Future 1 (2020$M)	Future 2 (2020$M)
AEPW	$43.2	$59.9
EMDE	$4.9	$6.8
GMO	$7.9	$11.0
GRDA	$3.5	$4.9
KCBPU	$1.9	$2.7
KCPL	$15.8	$21.9
LES	$3.0	$4.2
MIDW	$1.6	$2.2
NPPD	$12.7	$17.6
OKGE	$27.5	$38.2
OPPD	$9.7	$13.5
SPRM	$2.8	$3.9
SPS	$24.3	$33.7
SUNC	$4.6	$6.3
SWPA	$1.5	$2.1

---

[29] SPP Regional Cost Allocation Review Report, October 8, 2013 (pp. 36-37)

Zone	Future 1 (2020$M)	Future 2 (2020$M)
UMZ	$20.0	$27.8
WERE	$20.8	$28.9
WFEC	$6.9	$9.6
Total:	**$212.7**	**295.0**

Table 8.6: Transmission Outage Cost Mitigation Benefits by Zone

8.1.10 INCREASED WHEELING THROUGH AND OUT REVENUES

Increasing available transfer capacity (ATC) with a neighboring region improves import and export opportunities for the SPP footprint. Increased interregional transmission capacity that allows for increased through and out transactions will also increase SPP wheeling revenues.

To estimate how increased ATC could affect the wheeling services sold, the historical long-term firm transmission service request (TSR) allowed by the historical NTC projects are analyzed and compared against the ATC increase in the 2014 powerflow models estimated based on a First-Contingency Incremental Transfer Capability (FCITC) analysis. As summarized in Table 8.7, the NTC projects that have been put in-service under SPP's highway/byway cost allocation methodology enabled 13 long-term TSRs to be sold between 2010 and 2014. The TSRs remain active for 2020. The amount of capacity granted for these TSRs add up to 1,402 MW. The associated wheeling revenues are estimated to be $50.4 million annually based on current SPP tariff rates. The results of the FCITC analysis are summarized in Table 8.8. The export ATC increase in the 2014 powerflow models is calculated to be 1,142 MW, which is comparable to the amount of firm capacity granted for the incremental TSRs sold historically for 2020.

Point of Delivery	Number of Firm PtP Service Requests	MW Capacity Granted	2014 Wheeling Revenues in $million			
			Sch 7 Zonal	Sch 11 Reg-Wide	Sch 11 Thru & Out Zonal	TOTAL
AECI	6	716	$8.3	$11.8	$5.4	**$25.6**
KACY	1	100	$1.4	$1.7	$0.8	**$3.9**
Entergy	6	586	$6.8	$9.7	$4.4	**$20.9**
Total:	**13**	**1,402**	**$16.5**	**$23.2**	**$10.6**	**$50.4**

Table 8.7: Estimated Wheeling Revenues from Incremental Long-Term TSRs Sold (2010-2014)

Export ATC in 2014 Base Case	**1,630 MW**
Export ATC in 2014 Change Case	**2,943 MW**
Increase in Export ATC due to NTCs	**1,313 MW**
Incremental TSRs Sold due to NTCs	**1,402 MW**
TSRs Sold as a Percent of Increase in Export ATC	**107%**

Table 8.8: Historical Ratio of TSRs Sold against Increase in Export ATC

The 2025 and 2030 base reliability powerflow models were utilized for the FCITC analysis on the final consolidated portfolio. The ratio of TSRs sold as a percent of increase in export ATC is capped at 100 percent, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The recommended portfolio increased the export ATC by 104 MW in 2025 and 234 MW in 2030. Applying the historical ratio suggests the recommended portfolio could enable incremental TSRs by the same amount, generating additional wheeling revenues of $5-12 million annually.

The 40-year NPV of benefits is estimated to be $226 million. These benefits are allocated based on the current revenue sharing method in the tariff. Figure 8.2 shows the distribution of wheeling revenue benefits in each SPP zone.

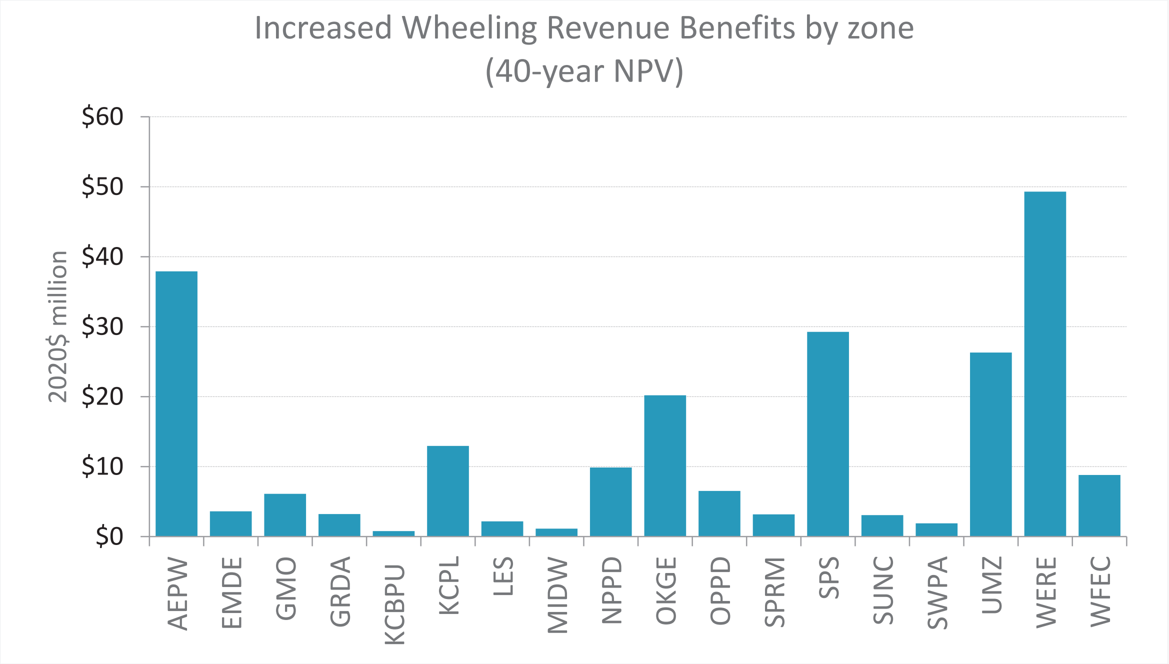


Figure 8.2: Increased Wheeling Revenue Benefits by Zone (40-year NPV)

8.1.11 MARGINAL ENERGY LOSSES BENEFIT

The standard production cost simulations used to estimate APC do not reflect the impact of transmission upgrades on the MWh quantity of transmission losses. To make run-times more manageable, the load in the production cost simulations is “grossed up” for average transmission losses for each zone. These loss assumptions do not change with additional transmission. Therefore, the traditional APC metric does not capture the benefits from reduced MWh quantity of losses.

APC savings due to such energy loss reductions can be estimated by post-processing the marginal loss component (MLC) of the LMPs from simulation results and applying a methodology[30] for marginal energy losses, which accounts for losses on generation and market imports. The 40-year NPV of benefits is estimated to be $10.97 million in Future 1 and $14.7 million in Future 2, as shown in Table 8.9.

	Reference Case (F1)			Emerging Technologies (F2)		
Zone	2025 ($M)	2030 ($M)	40-yr NPV (2020$M)	2025 ($M)	2030 ($M)	40-yr NPV (2020$M)
AEPW	($0.09)	($1.3)	($22.6)	($1.16)	($1.19)	($15.37)
EMDE	($0.2)	($0.3)	($4.3)	($0.30)	$0.01	$1.73
GMO	$0.34	$0.4	$5.9	$0.71	$0.22	$0.30
GRDA	($0.3)	($0.5)	($7.3)	($0.30)	($0.27)	($3.37)
KCBPU	$0.27	$0.4	$5.2	($0.33)	$0.14	$4.15
KCPL	$0.4	$0.5	$7.3	$0.25	$0.09	$0.30
LES	$0.03	$0.2	$2.7	$0.02	$0.07	$1.12
MIDW	($0.0)	($0.1)	($1.1)	($0.02)	($0.02)	($0.34)
NPPD	$0.06	$0.5	$7.9	$0.22	$0.23	$2.95
OKGE	($0.2)	($1.2)	($19.8)	$0.44	$0.14	$0.31
OPPD	$0.15	$1.4	$23.5	$0.31	$0.18	$1.61
SPRM	$0.0	$0.1	$2.0	$0.24	$0.25	$3.19
SPS	$1.91	$2.0	$25.8	$1.61	$2.07	$28.69
SUNC	$0.1	$0.1	$1.8	$0.18	$0.02	($0.59)
SWPA	($0.03)	($0.0)	($0.3)	($0.03)	$0.06	$1.26
UMZ	$0.2	$0.1	$1.3	$0.21	($0.73)	($14.04)
WERE	$0.64	($0.1)	($4.4)	($0.03)	($0.23)	($3.92)
WFEC	$0.2	($0.6)	($12.5)	($4.93)	($0.99)	$6.76
Total:	**$3.56**	**$1.61**	**$10.97**	**($2.89)**	**$0.03**	**$14.75**

Table 8.9: Energy Losses Benefit by Zone

8.1.12 SUMMARY

Table 8.10 through Table 8.13 summarize the 40-year NPV of the estimated benefit metrics and costs and the resulting B/C ratios for each SPP zone.

For the region, the B/C ratio is estimated to be 4.0 in Future 1 and 5.2 in Future 2. The higher B/C ratio in Future 2 is driven by the APC savings due to higher congestion relief.

---

[30] As described in the Benefit Metric Manual

Reference Case (Future 1)											
Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)										Present	Est.
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
AEPW	$350	$0	$1	$28	$0	$43	$23	($23)	$423	$93	4.6
EMDE	$39	$0	($0)	$4	$0	$5	$2	($4)	$46	$8	5.5
GMO	$20	$0	$0	$15	$0	$8	$4	$6	$53	$13	4.0
GRDA	$186	$0	$0	$2	$0	$4	$2	($7)	$187	$7	27.1
KCBPU	$12	$0	($0)	$3	$0	$2	$0	$5	$22	$3	6.6
KCPL	$57	$0	$0	$18	$0	$16	$8	$7	$106	$32	3.3
LES	$4	$0	$0	$5	$0	$3	$1	$3	$16	$5	3.2
MIDW	($21)	$0	$0	$4	$0	$2	$1	($1)	($15)	$3	(5.8)
NPPD	$12	$0	$0	$12	$0	$13	$6	$8	$51	$25	2.0
OKGE	$854	$0	$6	$27	$0	$28	$12	($20)	$907	$61	14.9
OPPD	($8)	$0	($0)	$7	$0	$10	$4	$23	$36	$16	2.2
SPRM	$6	$0	($0)	$6	$0	$3	$2	$2	$18	$5	3.9
SPS	$1	$0	$1	$4	$0	$24	$18	$26	$73	$92	0.8
SUNC	($67)	$0	$0	$4	$0	$5	$2	$2	($55)	$11	(4.9)
SWPA	$12	$0	$18	$45	$0	$2	$1	($0)	$77	$3	27.9
UMZ	$134	$0	$7	$11	$0	$20	$16	$1	$190	$65	2.9
WERE	$83	$0	$1	$14	$0	$21	$30	($4)	$145	$159	0.9
WFEC	$165	$0	$3	$7	$0	$7	$5	($12)	$175	$31	5.6
Total:	**$1,840**	**$0**	**$38**	**$217**	**$0**	**$213**	**$137**	**$11**	**$2,456**	**$634**	**3.9**

Table 8.10: Estimated 40-year NPV of Benefit Metrics and Costs-Zonal

Emerging Technologies (Future 2)											
	Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)									Present	Est.
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
AEPW	$588	$0	$1	$28	$0	$60	$23	($15)	$685	$93	7.4
EMDE	$50	$0	($0)	$4	$0	$7	$2	$2	$65	$8	7.8
GMO	$57	$0	$0	$15	$0	$11	$4	$0	$87	$13	6.5
GRDA	$152	$0	$0	$2	$0	$5	$2	($3)	$158	$7	22.9
KCBPU	$38	$0	($0)	$3	$0	$3	$0	$4	$47	$3	14.4
KCPL	$30	$0	$0	$18	$0	$22	$8	$0	$78	$32	2.4
LES	$26	$0	$0	$5	$0	$4	$1	$1	$38	$5	7.4
MIDW	($17)	$0	$0	$4	$0	$2	$1	($0)	($10)	$3	(3.8)
NPPD	$17	$0	$0	$12	$0	$18	$6	$3	$55	$25	2.2
OKGE	$980	$0	$6	$27	$0	$38	$12	$0	$1,063	$61	17.4
OPPD	$21	$0	($0)	$7	$0	$13	$4	$2	$47	$16	2.9
SPRM	$2	$0	($0)	$6	$0	$4	$2	$3	$17	$5	3.5
SPS	($12)	$0	$1	$4	$0	$34	$18	$29	$73	$92	0.8
SUNC	($52)	$0	$0	$4	$0	$6	$2	($1)	($41)	$11	(3.7)
SWPA	$34	$0	$18	$45	$0	$2	$1	$1	$102	$3	36.9
UMZ	$361	$0	$7	$11	$0	$28	$16	($14)	$410	$65	6.3
WERE	$58	$0	$1	$14	$0	$29	$30	($4)	$129	$159	0.8
WFEC	$248	$0	$3	$7	$0	$10	$5	$7	$280	$31	8.9
Total:	**$2,581**	**$0**	**$38**	**$217**	**$0**	**$295**	**$137**	**$15**	**$3,283**	**$634**	**5.2**

Table 8.11: Estimated 40-year NPV of Benefit Metrics and Costs-Zonal

Reference Case (Future 1)[31]										
Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)									Present	Est.
States	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
Arkansas	$85	$0	$0	$12	$0	$13	$6	($3)	$114	$26	4.5
Iowa	$28	$0	$0	$0	$0	$1	$0	($1)	$28	$1	21.4
Kansas	$83	$0	$26	$75	$0	$59	$41	$41	$324	$185	1.7
Louisiana	$51	$0	$0	$4	$0	$6	$3	($3)	$62	$14	4.6
Minnesota	$5	$0	$0	$0	$0	$0	$0	($0)	$5	$0	27.1
Missouri	$923	$0	$7	$62	$0	$56	$26	$7	$1,079	$115	9.4
Montana	$3	$0	$0	$0	$0	$0	$0	($0)	$3	$0	27.1
Oklahoma	$193	$0	$1	$27	$0	$34	$17	($6)	$267	$70	3.8
Nebraska	$266	$0	$5	$24	$0	$30	$36	($12)	$348	$194	1.8
New Mexico	($7)	$0	$0	$2	$0	$1	$0	($0)	($5)	$1	(5.8)
North Dakota	$83	$0	$0	$1	$0	$2	$1	($3)	$83	$3	27.1
South Dakota	$60	$0	$0	$1	$0	$1	$1	($2)	$60	$2	27.0
Texas	$67	$0	$0	$9	$0	$11	$6	($6)	$88	$23	3.8
Wyoming	$1	$0	$0	$0	$0	$0	$0	($0)	$1	$0	27.1
Total:	**$1,840**	**$0**	**$38**	**$217**	**$0**	**$213**	**$137**	**$11**	**$2,456**	**$634**	**3.9**

Table 8.12: Estimated 40-year NPV of Benefit Metrics and Costs-State

---

[31] State level numbers are representative of load and generation in the SPP region, not the entire state.

Reference Case (Future 1)											
Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)										Present	Est.
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
AEPW	$350	$0	$1	$28	$0	$43	$23	($23)	$423	$93	4.6
EMDE	$39	$0	($0)	$4	$0	$5	$2	($4)	$46	$8	5.5
GMO	$20	$0	$0	$15	$0	$8	$4	$6	$53	$13	4.0
GRDA	$186	$0	$0	$2	$0	$4	$2	($7)	$187	$7	27.1
KCBPU	$12	$0	($0)	$3	$0	$2	$0	$5	$22	$3	6.6
KCPL	$57	$0	$0	$18	$0	$16	$8	$7	$106	$32	3.3
LES	$4	$0	$0	$5	$0	$3	$1	$3	$16	$5	3.2
MIDW	($21)	$0	$0	$4	$0	$2	$1	($1)	($15)	$3	(5.8)
NPPD	$12	$0	$0	$12	$0	$13	$6	$8	$51	$25	2.0
OKGE	$854	$0	$6	$27	$0	$28	$12	($20)	$907	$61	14.9
OPPD	($8)	$0	($0)	$7	$0	$10	$4	$23	$36	$16	2.2
SPRM	$6	$0	($0)	$6	$0	$3	$2	$2	$18	$5	3.9
SPS	$1	$0	$1	$4	$0	$24	$18	$26	$73	$92	0.8
SUNC	($67)	$0	$0	$4	$0	$5	$2	$2	($55)	$11	(4.9)
SWPA	$12	$0	$18	$45	$0	$2	$1	($0)	$77	$3	27.9
UMZ	$134	$0	$7	$11	$0	$20	$16	$1	$190	$65	2.9
WERE	$83	$0	$1	$14	$0	$21	$30	($4)	$145	$159	0.9
WFEC	$165	$0	$3	$7	$0	$7	$5	($12)	$175	$31	5.6
Total:	**$1,840**	**$0**	**$38**	**$217**	**$0**	**$213**	**$137**	**$11**	**$2,456**	**$634**	**3.9**

Table 8.10: Estimated 40-year NPV of Benefit Metrics and Costs-Zonal

Emerging Technologies (Future 2)											
Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)										Present	Est.
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
AEPW	$588	$0	$1	$28	$0	$60	$23	($15)	$685	$93	7.4
EMDE	$50	$0	($0)	$4	$0	$7	$2	$2	$65	$8	7.8
GMO	$57	$0	$0	$15	$0	$11	$4	$0	$87	$13	6.5
GRDA	$152	$0	$0	$2	$0	$5	$2	($3)	$158	$7	22.9
KCBPU	$38	$0	($0)	$3	$0	$3	$0	$4	$47	$3	14.4
KCPL	$30	$0	$0	$18	$0	$22	$8	$0	$78	$32	2.4
LES	$26	$0	$0	$5	$0	$4	$1	$1	$38	$5	7.4
MIDW	($17)	$0	$0	$4	$0	$2	$1	($0)	($10)	$3	(3.8)
NPPD	$17	$0	$0	$12	$0	$18	$6	$3	$55	$25	2.2
OKGE	$980	$0	$6	$27	$0	$38	$12	$0	$1,063	$61	17.4
OPPD	$21	$0	($0)	$7	$0	$13	$4	$2	$47	$16	2.9
SPRM	$2	$0	($0)	$6	$0	$4	$2	$3	$17	$5	3.5
SPS	($12)	$0	$1	$4	$0	$34	$18	$29	$73	$92	0.8
SUNC	($52)	$0	$0	$4	$0	$6	$2	($1)	($41)	$11	(3.7)
SWPA	$34	$0	$18	$45	$0	$2	$1	$1	$102	$3	36.9
UMZ	$361	$0	$7	$11	$0	$28	$16	($14)	$410	$65	6.3
WERE	$58	$0	$1	$14	$0	$29	$30	($4)	$129	$159	0.8
WFEC	$248	$0	$3	$7	$0	$10	$5	$7	$280	$31	8.9
Total:	**$2,581**	**$0**	**$38**	**$217**	**$0**	**$295**	**$137**	**$15**	**$3,283**	**$634**	**5.2**

Table 8.11: Estimated 40-year NPV of Benefit Metrics and Costs-Zonal

Reference Case (Future 1)[31]											
	Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)									Present	Est.
States	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
Arkansas	$85	$0	$0	$12	$0	$13	$6	($3)	$114	$26	4.5
Iowa	$28	$0	$0	$0	$0	$1	$0	($1)	$28	$1	21.4
Kansas	$83	$0	$26	$75	$0	$59	$41	$41	$324	$185	1.7
Louisiana	$51	$0	$0	$4	$0	$6	$3	($3)	$62	$14	4.6
Minnesota	$5	$0	$0	$0	$0	$0	$0	($0)	$5	$0	27.1
Missouri	$923	$0	$7	$62	$0	$56	$26	$7	$1,079	$115	9.4
Montana	$3	$0	$0	$0	$0	$0	$0	($0)	$3	$0	27.1
Oklahoma	$193	$0	$1	$27	$0	$34	$17	($6)	$267	$70	3.8
Nebraska	$266	$0	$5	$24	$0	$30	$36	($12)	$348	$194	1.8
New Mexico	($7)	$0	$0	$2	$0	$1	$0	($0)	($5)	$1	(5.8)
North Dakota	$83	$0	$0	$1	$0	$2	$1	($3)	$83	$3	27.1
South Dakota	$60	$0	$0	$1	$0	$1	$1	($2)	$60	$2	27.0
Texas	$67	$0	$0	$9	$0	$11	$6	($6)	$88	$23	3.8
Wyoming	$1	$0	$0	$0	$0	$0	$0	($0)	$1	$0	27.1
Total:	**$1,840**	**$0**	**$38**	**$217**	**$0**	**$213**	**$137**	**$11**	**$2,456**	**$634**	**3.9**

Table 8.12: Estimated 40-year NPV of Benefit Metrics and Costs-State

---

[31] State level numbers are representative of load and generation in the SPP region, not the entire state.

Emerging Technologies (Future 2)[32]											
	Present Value of 40-yr Benefits for the 2025-2065 Period (in 2020$M)									Present	Est.
States	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2020$M)	Benefit/ Cost Ratio
Arkansas	$150	$0	$0	$12	$0	$18	$6	($3)	$184	$26	7.2
Iowa	$24	$0	$0	$0	$0	$1	$0	($0)	$25	$1	19.2
Kansas	$346	$0	$26	$74	$0	$81	$41	$20	$587	$185	3.2
Louisiana	$86	$0	$0	$4	$0	$9	$3	($2)	$100	$14	7.4
Minnesota	$4	$0	$0	$0	$0	$0	$0	($0)	$4	$0	22.9
(Missouri	$1,078	$0	$7	$62	$0	$78	$26	$3	$1,252	$115	10.9
Montana	$2	$0	$0	$0	$0	$0	$0	($0)	$2	$0	22.9
Oklahoma	$307	$0	$1	$27	$0	$48	$17	($2)	$398	$70	5.7
Nebraska	$347	$0	$5	$24	$0	$41	$36	$7	$460	$194	2.4
New Mexico	($6)	$0	$0	$2	$0	$1	$0	($0)	($4)	$1	(3.8)
North Dakota	$67	$0	$0	$1	$0	$2	$1	($1)	$70	$3	22.9
South Dakota	$49	$0	$0	$1	$0	$2	$1	($1)	$51	$2	22.9
Texas	$125	$0	$0	$9	$0	$15	$6	($4)	$151	$23	6.6
Wyoming	$1	$0	$0	$0	$0	$0	$0	($0)	$1	$0	22.9
Total:	**$2,581**	**$0**	**$38**	**$217**	**$0**	**$295**	**$137**	**$15**	**$3,283**	**$634**	**5.2**

Table 8.13: Estimated 40-year NPV of Benefit Metrics and Costs-State

---

[32] State level numbers are representative of load and generation in the SPP region, not the entire state.

8.2 RATE IMPACTS

The rate impact to an average retail residential ratepayer in SPP was computed for the recommended portfolio. Rate impact costs and benefits[33] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kWh per month. Benefits and costs for the 2030 study year were used to calculate rate impacts. All 2030 benefits and costs are shown in 2020 dollars, discounting at a 2.5 percent inflation rate.

The retail residential rate impact benefit is subtracted from the retail residential rate impact cost to obtain a net rate impact cost by zone. If the net rate impact cost is negative, it indicates a net benefit to the zone. The rate impact costs and benefits are shown in Table 8.14 through Table 8.17. There is a monthly net benefit for the average SPP residential ratepayer of 16 cents for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of 30 cents for Future 2.

Zone	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2020$)
AEPW	$7,896	$17,468	$0.15	$0.34	($0.19)
EMDE	$719	$2,859	$0.14	$0.56	($0.42)
GMO	$1,156	$950	$0.12	$0.10	$0.02
GRDA	$581	$10,114	$0.06	$1.05	($0.99)
KCBPU	$283	$496	$0.10	$0.18	($0.08)
KCPL	$2,688	$2,940	$0.18	$0.20	($0.02)
LES	$443	$230	$0.13	$0.07	$0.06
MIDW	$227	($1,145)	$0.10	($0.50)	$0.60
NPPD	$1,854	$577	$0.11	$0.03	$0.07
OKGE	$5,184	$44,561	$0.16	$1.33	($1.18)
OPPD	$1,417	($281)	$0.10	($0.02)	$0.12
SPRM	$408	$509	$0.14	$0.18	($0.04)
SPS	$7,336	($63)	$0.25	$0.00	$0.25
SUNC	$910	($3,729)	$0.14	($0.56)	$0.70
SWPA	$235	$583	$0.43	$1.07	($0.64)
UMZ	$5,297	$7,186	$0.17	$0.23	($0.06)
WERE	$13,179	$4,675	$0.49	$0.17	$0.31
WFEC	$2,521	$8,817	$0.16	$0.56	$0.40
Total:	**$52,334**	**$96,748**	**$0.19**	**$0.35**	**($0.16)**

Table 8.14: Future 1 2030 Retail Residential Rate Impacts by Zone (2020$)

---

[33] APC savings are the only benefit included in the rate impact calculations.

Zone	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2020$)
AEPW	$7,896	$29,423	$0.15	$0.57	($0.42)
EMDE	$719	$4,016	$0.14	$0.79	($0.65)
GMO	$1,156	$2,901	$0.12	$0.31	($0.19)
GRDA	$581	$8,221	$0.06	$0.86	($0.80)
KCBPU	$283	$1,665	$0.10	$0.60	($0.50)
KCPL	$2,688	$1,269	$0.18	$0.09	$0.10
LES	$443	$1,230	$0.12	$0.35	($0.22)
MIDW	$227	($1,009)	$0.10	($0.44)	$0.54
NPPD	$1,854	$732	$0.11	$0.04	$0.06
OKGE	$5,184	$50,551	$0.15	$1.51	($1.35)
OPPD	$1,417	$1,110	$0.10	$0.08	$0.02
SPRM	$408	$327	$0.14	$0.11	$0.03
SPS	$7,336	$1,530	$0.25	$0.05	$0.20
SUNC	$910	($3,052)	$0.14	($0.46)	$0.60
SWPA	$235	$1,853	$0.43	$3.41	($2.98)
UMZ	$5,297	$18,039	$0.17	$0.08	($0.40)
WERE	$13,179	$3,594	$0.49	$0.13	$0.35
WFEC	$2,521	$12,985	$0.16	$0.82	$0.60
Total:	**$52,334**	**$135,386**	**$0.19**	**$0.49**	**($0.30)**

Table 8.15: Future 2 2030 Retail Residential Rate Impacts by Zone (2020$)

State[34]	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact[35] (2020$)
Arkansas	$1,972	$4,773	$0.15	$0.36	($0.21)
Iowa	$84	$1,415	$0.06	$1.08	($1.02)
Kansas	$18,815	$9,380	$0.17	$0.09	$0.09
Louisiana	$1,155	$2,556	$0.15	$0.34	($0.19)
Minnesota	$16	$278	$0.06	$1.09	($1.02)
Missouri	$8,148	$46,549	$0.14	$0.81	($0.67)
Montana	$9	$151	$0.06	$1.09	($1.02)
Nebraska	$8,234	$11,123	$0.20	$0.26	($0.07)
New Mexico	$411	$338	$0.50	$0.41	$0.09
North Dakota	$257	$4,481	$0.06	$1.09	($1.02)
Oklahoma	$10,488	$7,735	$0.39	$0.29	$0.10
South Dakota	$195	$3,276	$0.06	$1.08	($1.01)
Texas	$2,545	$4,616	$0.19	$0.35	($0.16)
Wyoming	$4	$77	$0.06	$1.09	($1.02)
Total:	**$52,334**	**$96,748**	**$0.19**	**$0.35**	**($0.16)**

Table 8.16: Future 1 2030 Retail Residential Rate Impacts by State (2020$)

---

[34] State level numbers are representative of load and generation in the SPP region, not the entire state.

[35] State level results are based on load allocations by zone, by state. For example, 4.2 percent of Upper Missouri Zone (UMZ) load is in Nebraska, so 4.2 percent of UMZ benefits are attributed to Nebraska.

State[36]	One-Year ATRR Costs 2030 ($thousands)	One-Year Benefit 2030 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact[37] (2020$)
Arkansas	$1,972	$7,700	$0.15	$0.59	($0.44)
Iowa	$84	$1,164	$0.06	$0.89	($0.83)
Kansas	$18,815	$13,928	$0.17	$0.13	$0.05
Louisiana	$1,155	$4,305	$0.15	$0.57	($0.42)
Minnesota	$16	$226	$0.06	$0.88	($0.82)
Missouri	$8,148	$56,385	$0.14	$0.98	($0.84)
Montana	$9	$123	$0.06	$0.88	($0.82)
Nebraska	$8,234	$21,487	$0.20	$0.51	($0.31)
New Mexico	$411	$1,031	$0.50	$1.26	($0.76)
North Dakota	$257	$3,642	$0.06	$0.88	($0.82)
Oklahoma	$10,488	$14,078	$0.39	$0.52	($0.13)
South Dakota	$195	$2,660	$0.06	$0.88	($0.81)
Texas	$2,545	$8,596	$0.19	$0.64	($0.45)
Wyoming	$4	$62	$0.06	$0.88	($0.82)
Total:	**$52,334**	**$135,386**	**$0.19**	**$0.49**	**($0.30)**

Table 8.17: Future 2 2030 Retail Residential Rate Impacts by State (2020$)

8.3 SENSITIVITY ANALYSIS

The recommended portfolio was tested under select sensitivities to understand the economic impacts associated with variations in certain model assumptions. These sensitivities were not used to develop transmission projects nor filter out projects, but rather to measure the flexibility of the final consolidated portfolio in both futures under different uncertainties. The demand and natural gas price sensitivities were included in the 2020 ITP Scope, however, SPP staff performed additional sensitivities to further explore the performance of the portfolio.

The following sensitivities were conducted:

- Scoped sensitivities
    - High/low natural gas price
    - High/low demand

---

[36] State level numbers are representative of load and generation in the SPP region, not the entire state.

[37] State level results are based on load allocations by zone, by state. For example, 4.2 percent of Upper Missouri Zone (UMZ) load is in Nebraska, so 4.2 percent of UMZ benefits are attributed to Nebraska.

- Supplemental sensitivities
    - High/low wind[38]
    - High/low solar
    - High/low energy storage
    - High/low unit retirements

The consolidated portfolio was tested in both futures. The APC savings impacts of variations in the model inputs were calculated for the simulations. Figure 8.3 illustrates the expected range of APC savings benefit in comparison to the range of portfolio cost and the impacts of varying sensitivity assumptions on that range of benefits. The cost ranges represent the ±30 percent Study Estimate requirement. The dashed bar in subsequent figures represents the expected case B/C ratio for comparison to the sensitivity case B/C ratios.

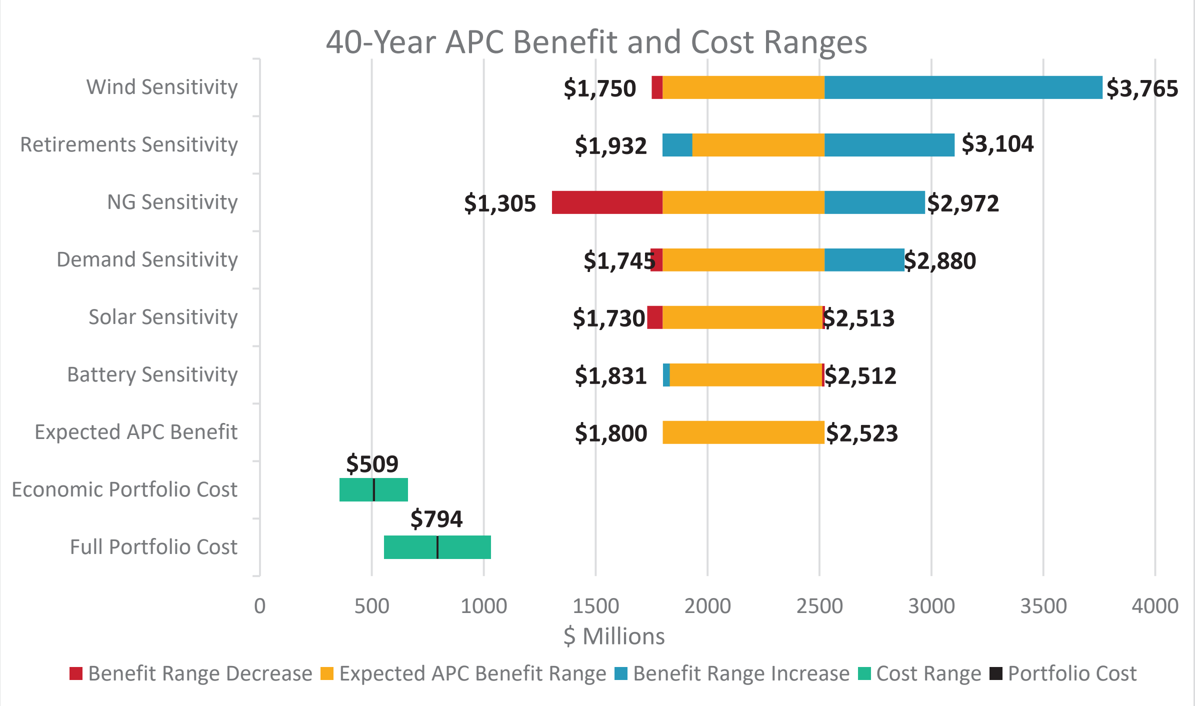


Figure 8.3: 40-Year APC Benefit and Cost Ranges

8.3.1 PEAK DEMAND SENSITIVITY

A single confidence interval for demand levels was developed from FERC Form No. 714. The demand sensitivities had a 67 percent confidence interval (1 standard deviation) in positive and negative directions.

The change in peak demand and energy reflects the SPP regional average volatility based on historical data. The average deviation from the projected 2030 load forecasts developed by the MDWG and

---

[38] Low wind sensitivity was only assessed in Future 2.

reviewed by the ESWG results in a ±7.5 percent change. This change was implemented on the load at a company level. For companies without available data, the SPP regional average confidence interval was used.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Peak Demand (GW)	**Low**	53	55	53	55
	Expected	58	59	58	59
	High	62	64	62	64

Table 8.18: Peak Demand Sensitivity

These high and low values were included as inputs to the base models of each future with and without the recommended portfolio. The results of the 40-year APC benefit for this sensitivity are reflected in Figure 8.4. An increase in demand creates an increase in congestion on the SPP system, resulting in higher congestion costs for the portfolios to mitigate, thus increasing the benefit. The opposite is true for the low demand case, which decreases the opportunity for the portfolio to mitigate congestion.

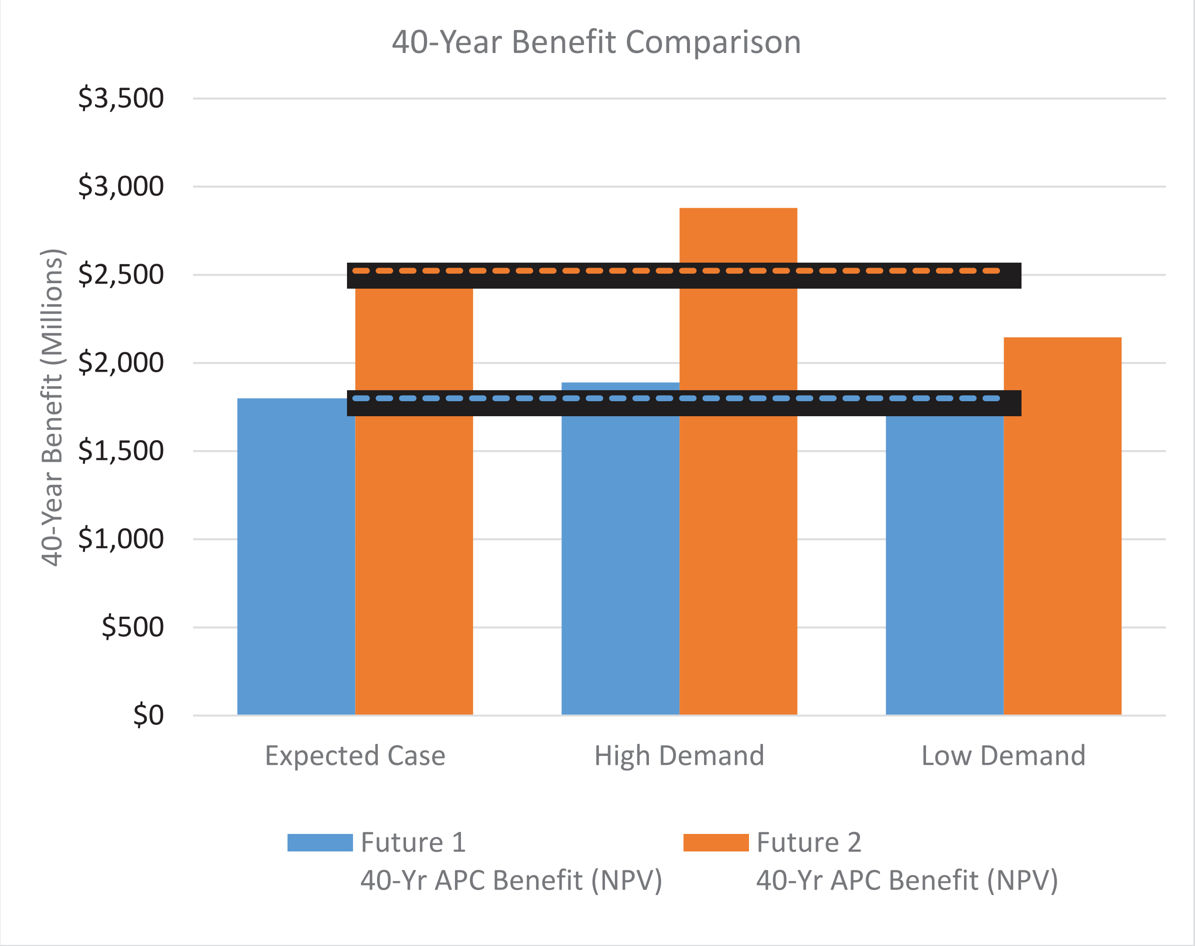


Figure 8.4: 40-Year Benefit Comparison (Peak Demand Sensitivity)

8.3.2 NATURAL GAS SENSITIVITY

A single confidence interval for natural gas prices was developed from the ABB fundamental forecast. The natural gas sensitivity had a 95 percent confidence interval (1.96 standard deviations) in positive and negative directions.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Natural Gas (2020$)	**Low**	2.72	2.95	2.72	2.95
	Expected	3.75	4.07	3.75	4.07
	High	4.79	5.19	4.79	5.19

Table 8.19: Natural Gas Sensitivity

A change in gas price is reflected by a corresponding change in the overall price of energy. The high natural gas sensitivity shows the portfolio's ability to reduce overall energy costs by allowing for a more economical generation dispatch. The low natural gas sensitivity shows a reduced benefit caused by lessened economic opportunity of resources with similar energy costs.

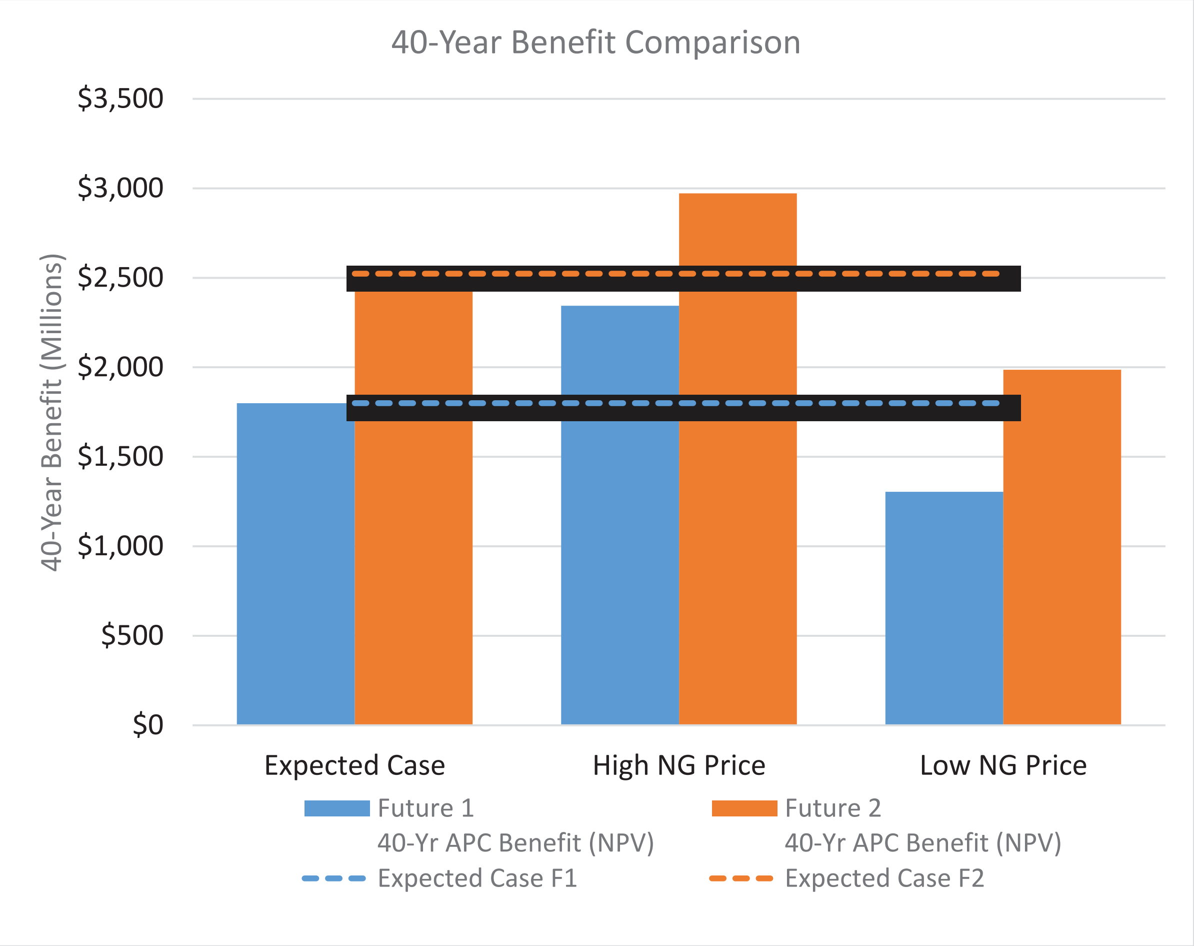


Figure 8.5: 40-Year Benefit Comparison (Natural Gas Sensitivity)

8.3.3 WIND CAPACITY SENSITIVITY

A wind sensitivity was conducted to test the portfolio's performance under alternative wind conditions. For this sensitivity, wind capacity and energy were scaled to the projected amounts shown in Table 8.20. For Future 1 only an increase in the wind capacity and energy was assessed due to the current growth of wind installation in real-time since scope development. For the high wind sensitivity, wind capacity and energy was added to existing and resource plan sites in the base case assumptions on a pro rata basis. For the low wind sensitivity, wind capacity and energy was reduced at only the resource plan sites.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Wind (GW)	**Low**	N/A	N/A	25	28
	Expected	26	28	30	33
	High	34	38	38	44

Table 8.20: Wind Capacity Sensitivity

Testing the portfolio against increased wind showed an increase in APC benefit. This influx of additional energy increases congestion in the base cases, leaving more congestion to be addressed by the project portfolio. The increase in benefit for both portfolios confirms that additional renewables would be facilitated by these specific sets of projects. For the reduced wind Future 2 sensitivity, the opposite occurs. A reduction in wind capacity and energy reduces the benefits the portfolio can realize.

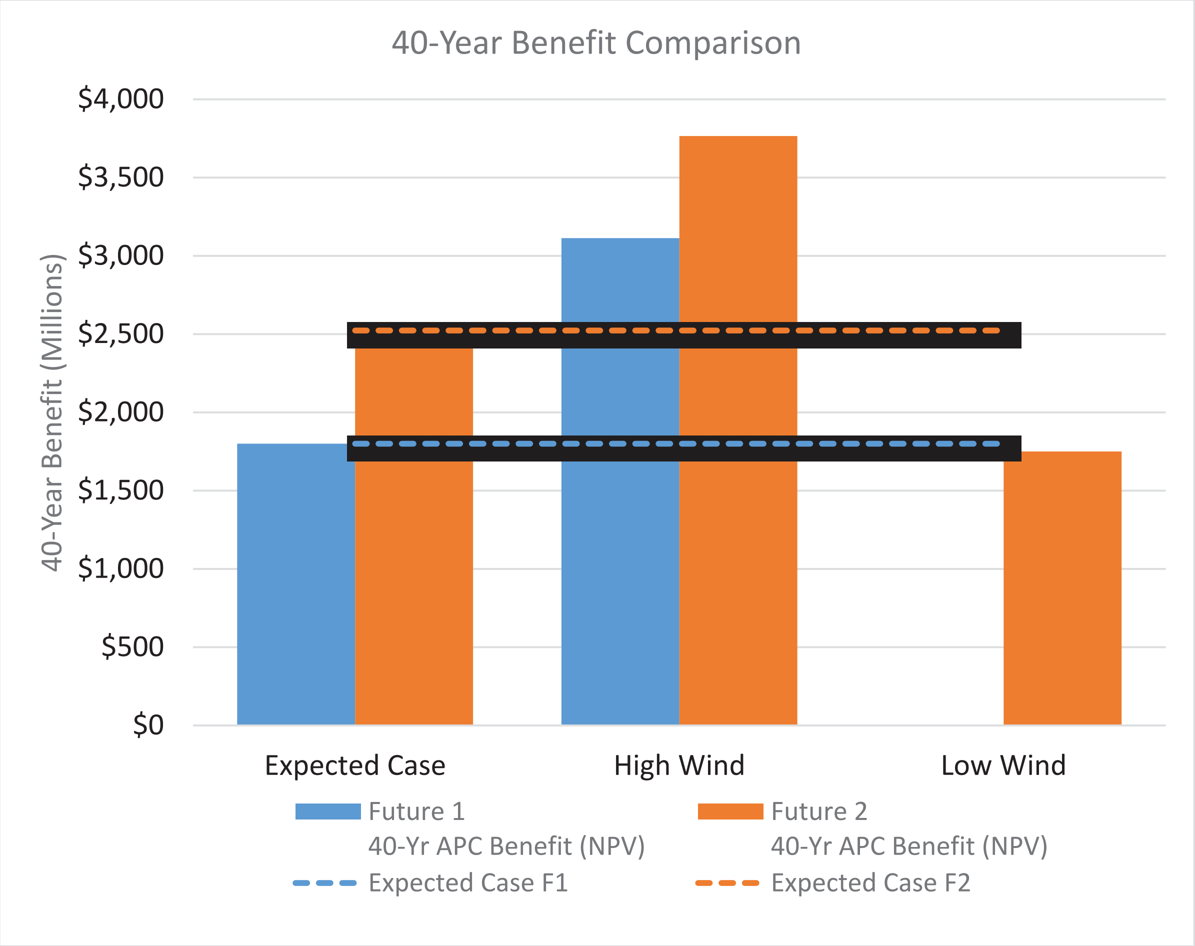


Figure 8.6: 40-Year Benefit Comparison (Wind Capacity Sensitivity)

8.3.4 SOLAR CAPACITY SENSITIVITY

Performance of the portfolio was assessed under varying solar capacity and energy assumptions. In this sensitivity, solar capacity and energy was scaled to the projected amounts shown in Table 8.21.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Solar (GW)	**Low**	0	0	0	0
	Expected	4	7	5	9
	High	9	11	10	13

Table 8.21: Solar Capacity Sensitivity

Like the wind sensitivity, increased solar capacity and energy reduces the overall cost of energy available to the system. This leads to similar changes in portfolio performance as those seen in the wind sensitivity, except for the high solar sensitivity in Future 2. The increased solar capacity and energy is competing with higher amounts of energy from wind resources with a lower cost of energy, which results in a negligible change due to the increase solar in Future 2.

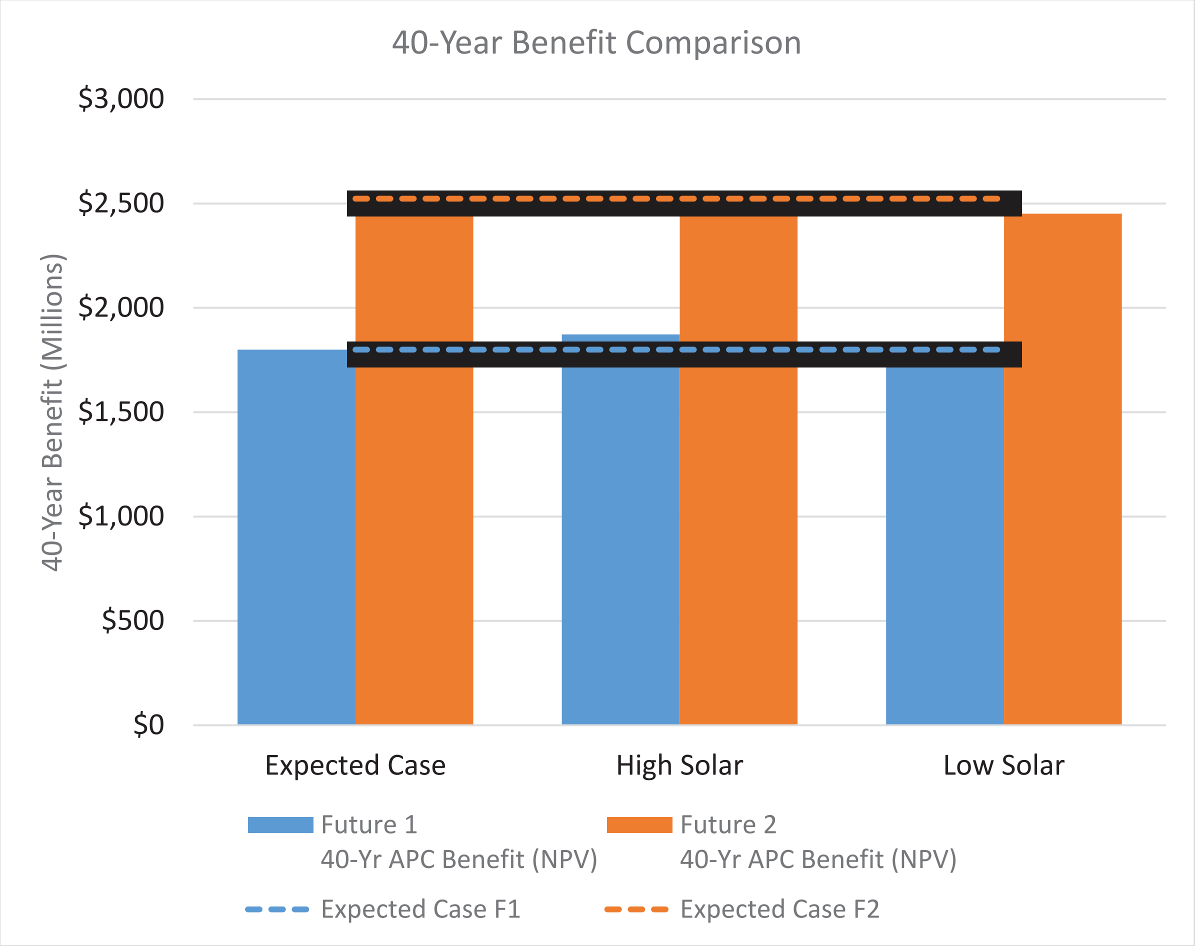


Figure 8.7: 40-Year Benefit Comparison (Solar Capacity Sensitivity)

8.3.5 ENERGY STORAGE SENSITIVITY

The 2020 ITP was the first study to incorporate the development of energy storage resources. To understand the impacts of energy storage on the portfolio a sensitivity was conducted. Energy storage amounts were scaled to the amounts shown in Table 8.22.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Energy Storage (GW)	**Low**	0.0	0.0	0.0	0.0
	Expected	0.8	1.4	1.7	3.1
	High	1.5	2.7	3.3	6.1

Table 8.22: Energy Storage Sensitivity

As illustrated in Figure 8.8 below, modifying the amounts of energy storage caused negligible effect on the benefits observed by the portfolio in an hourly simulation. More impacts would generally be expected in a sub-hourly simulation due to increased volatility.

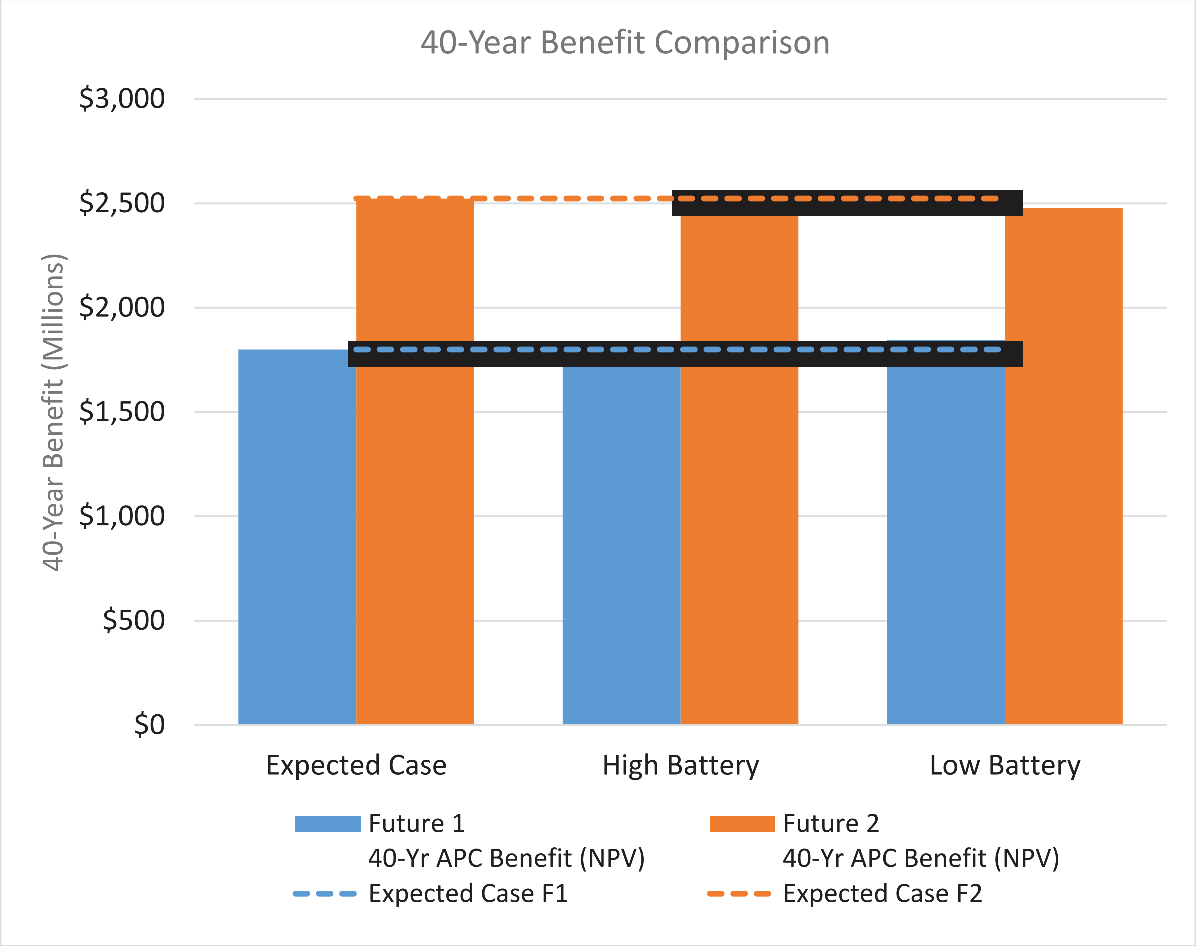


Figure 8.8: 40-Year Benefit Comparison (Energy Storage Sensitivity)

8.3.6 UNIT RETIREMENTS SENSITVITY

Retirement assumptions for the 2020 ITP resulted in additional capacity retirements compared to the 2019 ITP. As a result of stakeholders' concerns related to this assumption a sensitivity was conducted to understand the effect of varying this assumption. Table 8.23 shows the change in the amount of retirements, in gigawatts, for the low, expected, and high retirement amounts. For the low retirement sensitivity, the conventional resource plan units were deactivated from the simulation and the previously retired units were placed back in service. The high retirements sensitivity targeted coal facilities from the 2017 ITP10 with a lower than average capacity factor under emission restrictions, which were replaced by combustion turbines primarily at the same locations to maintain zonal reserve margins.

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Unit Retirements (GW)	**Low**	0	0	0	0
	Expected	6	11	13	17
	High	17	20	23	25

Table 8.23: Unit Retirements Sensitivity

All four scenarios of this sensitivity experienced increased congestion for the portfolio to address, which was somewhat unexpected. This can be explained by the wide range of variables as it relates to the SPP fleet. Locations of added/removed retirements, the large change in resource mix, and system congestion patterns all play a significant role in the APC of the system.

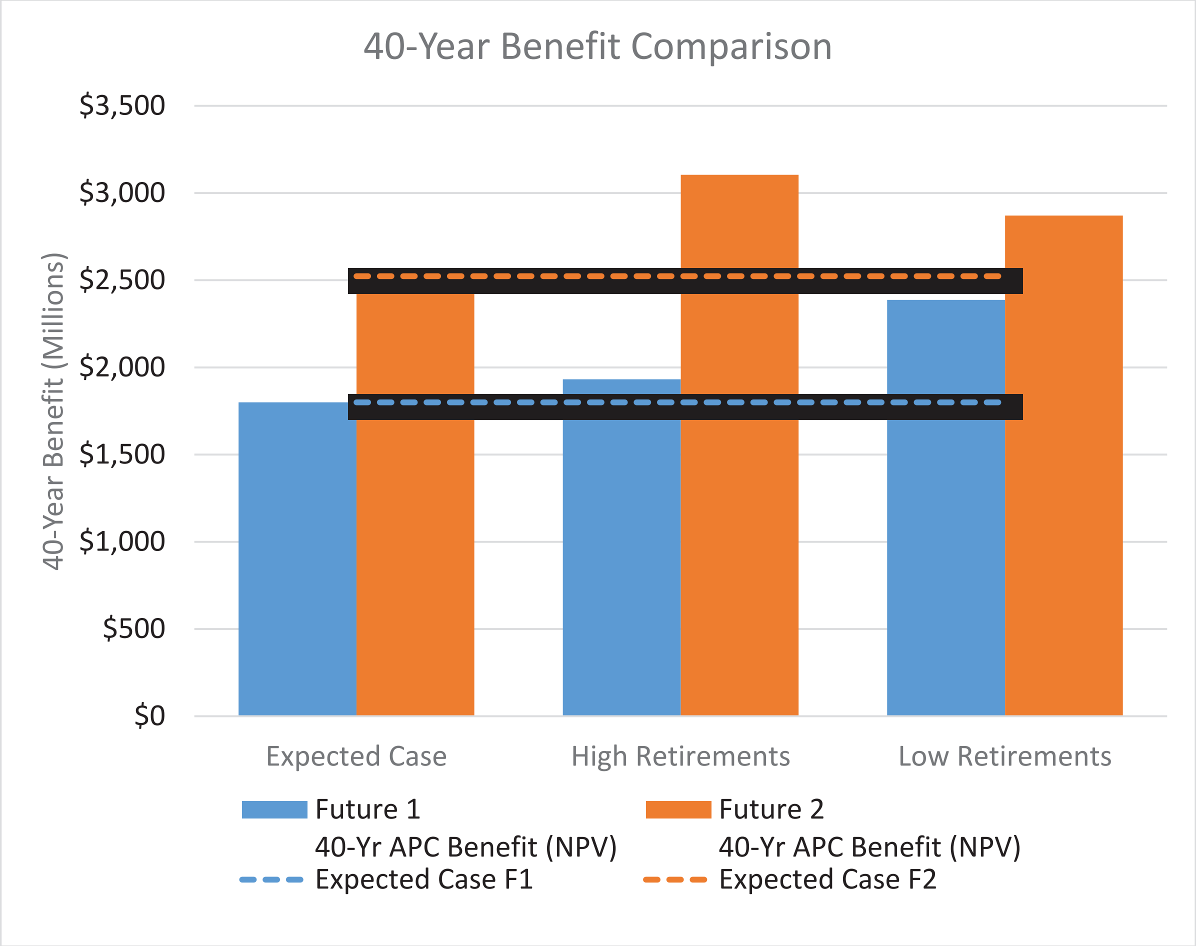


Figure 8.9: 40-Year Benefit Comparison (Unit Retirements Sensitivity)

8.4 VOLTAGE STABILITY ASSESSMENT

A voltage stability assessment was conducted with the recommended portfolio using Future 1 and 2 market powerflow models to assess the transfer limit (GW) from renewables in SPP to conventional thermal generation in SPP, and from renewables in SPP to conventional thermal generation in external areas.[39] The assessment was performed to determine whether the generation dispatch with the recommended portfolios adversely impacts system voltage stability. The assessment was intentionally scoped to determine how the planned system performs under high renewable dispatch, given the projected renewable amounts assumed for the 2020 ITP assessment.

The planned system supports the future-specific renewable generation dispatches observed in the reliability hours after modeling the consolidated portfolio, reaching either minimum internal conventional thermal generation levels or thermal limits prior to reaching voltage stability limits.

8.4.1 METHODOLOGY

To determine the amount of generation transfer that could be accommodated by the planned system, generation in the source zone was increased and generation in the sink zone was decreased. Table 8.24 identifies the transfer zones and boundaries.

Transfer Zones	Zone Boundaries
SPP renewables	SPP conventional thermal generation
SPP renewables	First-Tier and Second-Tier conventional thermal generation

Table 8.24: Generation Zones

Table 8.25 shows the transfers that were performed on the 2030 light load and 2030 summer models by scaling both on-line and off-line renewables from the source zone and scaling down the sink zone. Utility scale solar was not included in the source zone for the 2030 light for the 2029 light load model due to the reliability hour being identified as 4 a.m.

---

[39] See TWG 11/13/2018 meeting minutes and attachments for the TWG-approved 2020 ITP Voltage Stability Scope.

Model	Source Zone	Sink Zone
2030 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2030 Light Load	SPP renewables (Wind)	First-Tier and Second-Tier conventional thermal generation
2030 Summer	SPP renewables (Wind and Utility Scale Solar)	First-Tier and Second-Tier conventional thermal generation
2030 Summer	SPP renewables (Wind and Utility Scale Solar)	SPP conventional thermal generation

Table 8.25: Transfers by Model

Single contingencies (N-1) for all SPP branches, transformers, and ties greater than or equal to 345 kV were analyzed. SPP and first-tier 100 kV and above facilities were monitored for voltage and thermal violations. The initial condition for each model was the source zone sum of real power generation output (MW). The maximum source zone transfer capability was the real power maximum generation (Pmax). The transfers were performed on each model in 200 MW steps until voltage collapse occurred in the pre-contingency and post-contingency (N-1, 345 kV and 500 kV facilities) conditions. Each future was evaluated for increasing generation transfer amounts to determine different voltage collapse points of the transmission system. Source and sink generation was scaled on a pro-rata basis to reach the pre-contingency maximum power transfer limit, or the voltage stability limit (VSL). Multiple transfer limits were determined based on the worst N-1 contingency and independently evaluating the next worst contingency to determine the top five post-contingency VSL.

8.4.2 SUMMARY

Figure 8.2 shows a summary of the voltage stability assessment limits by future, model and transfer path. The table includes the transfer path, source and sink generation pre-transfer levels, critical contingency, post transfer level when VSL is reached, incremental transfer limit amount, and whether or not thermal overloads occur prior to voltage collapse. The table shows in all instances either minimum internal conventional thermal generation levels or when a thermal limit is reached prior to the VSL.

Transfer Source -->Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
Future 1: 2030 Light Load							
Wind -->Internal			Reached Minimum Sink				N/A
Wind -->External Thermal	19.7	18.3	Blackberry-Wolf Creek	21.5	17.0	1.8	Yes
"	19.7	18.3	Sooner-Wekiwa	21.5	17.0	1.8	Yes

Transfer Source -->Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
"	19.7	18.3	Terry Road-Sunnyside	21.5	17.0	1.8	Yes
Future 1: 2030 Summer Peak							
Solar & Wind -->Internal	21.1	28.7	Crossroad-Eddy County	26.2	23.8	5.2	Yes
"	21.1	28.7	Holt-S3458	26.2	23.8	5.2	Yes
Solar & Wind -->External	21.1	72.1	Ketchem-Sibley	26.7	67.5	5.4	Yes
"	21.1	72.1	La Cygne-Stillwell	26.6	67.5	5.4	Yes
"	21.1	72.1	JEC-Hoyt	26.8	67.3	5.7	Yes
Future 2: 2030 Light Load							
Wind -->Internal			Reached Minimum Sink				N/A
Wind -->External	18.8	17.9	Hugo-Sunnyside	21.0	16.1	1.8	Yes
"	18.8	17.9	Blackberry-Wolf Creek	21.6	15.7	2.2	Yes
"	18.8	17.9	Fort Smith-ANO	21.6	15.7	2.2	Yes
Future 2: 2030 Summer Peak							
Solar & Wind -->Internal	25.2	24.6	Crossroad-Eddy County	29.6	20.4	4.1	Yes
"	25.2	24.6	Terry Road-Sunnyside	39.0	11.6	13.0	Yes
"	25.2	24.6	Mathewson-Northwest	39.8	10.9	13.7	Yes
Solar & Wind -->External	25.2	70.5	Ketchem-Sibley	30.4	66.2	4.4	Yes
"	25.2	70.5	La Cygne-Stilwell	30.6	66.0	4.5	Yes
"	25.2	70.5	Blackberry-Wolf Creek	31.0	65.7	4.6	Yes

Table 8.26: Post-Contingency Voltage Stability Transfer Limit Summary

Table 8.27 shows a summary of the voltage stability assessment limits and thermal limits by future, model, and transfer path. The table includes the transfer path, total renewable capacity, post transfer level when thermal violations and VSLs are reached, and a comment summarizing either the minimum internal conventional thermal generation levels or when a thermal limit is reached prior to the VSL

Transfer Source-->Sink	Total Renewable Capacity (GW)	VSL Limit (GW)	Thermal Limit (GW)	Comment
Future 1: 2030 Light Load				
Wind-->Internal	**25.6**	N/A	N/A	
Wind-->External	**26.9**	21.5	20.2	
Future 1: 2030 Summer Peak				
Solar & Wind -->Internal	**33.1**	26.2	23.4	
Solar & Wind -->External	**33.1**	26.7	23.8	
Future 2: 2030 Light Load				
Wind-->Internal	**30.1**	N/A	N/A	
Wind-->External	**30.8**	21.0	20.2	
Future 2: 2030 Summer Peak				
Solar & Wind -->Internal	**40.2**	29.6	28.0	
Solar & Wind -->External	**41.2**	30.4	28.2	

Table 8.27: Voltage Stability Results Summary

8.4.3 CONCLUSION

The analysis demonstrates the planned system does not reach a VSL prior to system thermal limits; therefore, the potential benefits attributed to the consolidated portfolio are validated. Voltage collapse occurs at renewable levels less than the projected renewable capacity amounts. However, thermal issues (*i.e.*, causing renewable curtailments) occur prior to voltage collapse when thermal issues are captured in the market economic models as congestion. The APC benefit of the consolidated portfolio generally derives from relieving congestion on thermal issues. Voltage collapse occurs at aggregate renewable levels greater than what is observed in the reliability hours after modeling the consolidated portfolio.

8.5 FINAL RELIABILITY ASSESSMENT

8.5.1 METHODOLOGY

Thermal and voltage violations were identified in the market powerflow portfolio rebuilt models following the same methods in the base reliability powerflow assessment. There were three thermal violations identified a result of the new market dispatch and portfolio additions, although they were reclassified and invalidated as reliability violations per section 4.2.5 of the ITP Manual. No additional voltage violations were observed and no supplementary solutions were developed to accommodate the market powerflow models.

8.5.1.1 Short-Circuit Model

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2020 ITP year-two summer maximum fault current model to find percent increases in fault currents in relation to the base case model on which the needs assessment was performed. All consolidated portfolio projects expected to alter or need zero sequence data were added to the model regardless of their in-service dates.

After performing this analysis, it was found that 113 of the 9,888 buses monitored experienced a 5 percent increase in fault current. Only nine of the 113 buses appeared to exceed common breaker duty ratings of 20kA. The subsequent short-circuit analysis performed next cycle will confirm whether or not the duty ratings are exceeded given the latest modeling assumptions.

8.5.2 SUMMARY

8.5.2.1 Base Reliability Models

The resulting thermal and voltage violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, identification of invalid contingencies, non-load-serving buses, and facilities not under SPP's functional control. Additional rebuilds were identified as needed for portfolio inclusion based on downstream overloads resulting from rebuilds already selected in the proposed portfolio. Due to the fact that these sections of the Deaf Smith 115kV corridor were not up to minimum design standard, they have all been identified as rebuild projects. Per the ITP manual, base reliability projects driving additional needs require portfolio project adjustment or additions in order to fully mitigate the resulting needs. The details of the additional rebuilds are listed below.

Rebuild Projects	Portfolio Need Identification
Deaf Smith #6-Hereford 115 kV rebuild	Base Reliability
Deaf Smith #6-Friona 115 kV rebuild	Base Reliability
Cargill-Friona 115 kV rebuild	Final Reliability Assessment
Cargill-Deaf Smith #24 115 kV rebuild	Final Reliability Assessment
Parmer-Deaf Smith #24 115 kV rebuild	Final Reliability Assessment
Parmer-Deaf Smith #20 115 kV rebuild	Final Reliability Assessment
Curry-Deaf Smith #20 115 kV rebuild	Final Reliability Assessment

Table 8.28: Additional Identified Reliability Rebuilds

8.5.2.2 Market Powerflow Models

The resulting thermal and voltage violations identified in the market powerflow portfolio rebuilt models were generated using the same methods in the base reliability powerflow assessment. There were three thermal violations identified as resultant of the new market dispatch and portfolio additions, although they were reclassified and invalidated as reliability violations per Section 4.2.5 of the ITP Manual. Of the fifteen voltage violations identified, thirteen were related to local planning more stringent monitoring criteria and only two were low voltage per the SPP Planning Criteria. Per the ITP manual, no new solutions were developed for these identified violations, and the facilities will be monitored in the 2021 ITP for any further issues.

8.5.2.3 Short-Circuit Model

The final reliability assessment for the short-circuit model did not show any new fault-interrupting equipment to have its duty ratings exceeded by the maximum available fault current (potential violation) due to the addition of the consolidated portfolio.

8.5.3 CONCLUSION

Overall, only the Base Reliability assessment yielded any additional needs which were addressed by portfolio project additions per the direction provided in the ITP Manual.

9 NTC RECOMMENDATIONS

SPP staff makes NTC recommendations for projects included in the consolidated portfolio based on results from the staging process and SPP Business Practice 7060. If financial expenditure is required within four years from board approval, the project is generally recommended for an NTC or NTC-C. To determine the date when financial expenditure is required, the project's lead time is subtracted from its need date. Expected lead times for transmission projects are determined using historical data on construction timelines from SPP's project tracking process. NTC-Cs are issued for projects with an operating voltage greater than 100 kV and a Study Estimate greater than $20 million.

Two exceptions to this process for the 2020 ITP are the Eddy County-North Loving 345 kV line identified as a reliability project with a June 2028 need date and the Split Rock 345/115 kV terminal equipment identified as an economic project with a January 2025 need date for the reasons discussed in section 7.1.7 and 7.3.10, warranting additional analysis necessary in future planning studies before move forwarded with the planned projects.

As discussed throughout the report the eastern New Mexico area is extremely complex. Both economic and reliability issues are present and a comprehensive solution is necessary to address the thermal loading, low voltage, and voltage collapse conditions. The Eddy County-North Loving 345 kV line does not address some of these conditions as it is not a comprehensive solution. Additionally, there are some out of scope compliance events NERC TPL 001-4 P3 planning events that are also known to cause concerns in the area. SPP Operations staff is also currently working to update interface ratings due to transmission topology being placed in service in the near future. SPP expects to continue studying this in the 2021 ITP assessment with the goal of utilizing information gathered in the 2020 ITP along with new analysis to provide a comprehensive solution to address the system conditions in the area.

The terminal equipment that would require replacement to increase the rating of the Split Rock 345/115 kV transformers, which is not an SPP tariff facility and would require FERC filings to support SPP regionally beneficial seams project cost allocation. The project was also identified and assessed during the 2020 MISO-SPP CSP, but was not found to be jointly beneficial. Additionally, the project marginally passed SPP's consolidation criteria.

For the reasons listed above the Eddy County-North Loving 345 kV line and the Split Rock 345/115 kV terminal equipment upgrades are not recommended for an NTC.

Table 9.1 below shows SPP's NTC recommendations when considering staging results, expected lead times, and other qualitative information related to the recommended projects.

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Watford 230/115 kV transformer circuit 1 terminal equipment, circuit 2 replacement	6/1/2022	24	11/17/2020	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Circleville-Goff 115 kV circuit 1 rebuild	6/1/2025	24	6/1/2023	NTC
Goff-Kelly 115 kV rebuild	6/1/2025	24	6/1/2023	NTC
South Shreveport-Wallace Lake 138 kV rebuild	6/1/2024	24	6/1/2022	NTC-C
Grady 138 kV capacitor bank	12/1/2022	24	12/1/2020	NTC
Richmond 115 kV substation, Richmond 115/69 kV transformer, Richmond-Aberdeen 115 kV line	12/1/2022	36	11/17/2020	NTC
Cushing Tap-Shell Cushing Tap-Shell Pipeline 69 kV rebuild	6/1/2023	24	6/1/2021	NTC
Bushland-Deaf Smith 230 kV terminal equipment	4/1/2022	18	11/17/2020	NTC
Newhart-Potter County 230 kV terminal equipment	4/1/2022	18	11/17/2020	NTC
Carlisle-Murphy 115 kV rebuild	6/1/2022	24	11/17/2020	NTC
Roswell 115/69 kV replace transformer #1	6/1/2022	24	11/17/2020	NTC
S3456-S3458 345 kV terminal equipment	6/1/2029	18	12/1/2027	No
Meadowlark-Tower 33 115 kV rebuild	6/1/2023	36	11/17/2020	NTC
Jones-Lubbock South 230 kV terminal equipment circuit 1	6/1/2028	18	12/1/2026	No
Jones-Lubbock South 230 kV terminal equipment circuit 2	6/1/2028	18	12/1/2026	No
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2022	18	11/17/2020	NTC
Newhart-Plant X230 kV terminal equipment	4/1/2022	18	5/17/2022	NTC
Lubbock South-Wolfforth 230 kV terminal equipment and clearance increase	6/1/2022	18	12/1/2020	NTC
Allen-Lubbock South 115 kV rebuild	6/1/2022	24	11/17/2020	NTC
Allen-Quaker 115 kV rebuild	6/1/2022	24	11/17/2020	NTC
Eddy County-North Loving 345 kV new line	6/1/2028	48	6/1/2024	No
Bismarck 115 kV reactors	4/1/2022	24	11/17/2020	NTC
Moorehead 230 kV reactor	4/1/2022	24	11/17/2020	NTC
Russell 115 kV capacitor bank	6/1/2022	24	11/17/2020	NTC
Maljamar 115 kV capacitor bank	6/1/2028	24	6/1/2026	No
Devil's Lake 115 kV reactor	4/1/2022	24	11/17/2020	NTC
Agate 115 kV reactor	4/1/2022	24	11/17/2020	NTC
Nixa-Nixa Espy 69 kV terminal equipment	6/1/2022	18	12/1/2020	No
Replace four breakers at Anadarko 138 kV	6/1/2022	18	12/1/2020	NTC
Replace three breakers at Northeast 161 kV	6/1/2022	18	12/1/2020	NTC
Replace one breaker at Stilwell 161 kV	6/1/2022	18	12/1/2020	NTC
Replace one breaker at Leeds 161 kV	6/1/2022	18	12/1/2020	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Replace one breaker at Shawnee Mission 161 kV	6/1/2022	18	12/1/2020	NTC
Replace one breaker at Southtown 161 kV	6/1/2022	18	12/1/2020	NTC
Replace two breakers at Lake Road 161 kV	6/1/2022	18	12/1/2020	NTC
Replace two breakers at Craig 161 kV	6/1/2022	18	12/1/2020	NTC
Anadarko-Gracemont 138 kV rebuild as double-circuit	1/1/2023	36	11/17/2020	NTC-Modify
Russett-South Brown 138 kV rebuild	1/1/2022	30	11/17/2020	NTC
Butler-Tioga 138 kV new line; wreck-out Butler-Altoona 138 kV	1/1/2024	36	1/1/2021	NTC-C
GRDA 1 345/161 kV circuit 1 and circuit 2 terminal equipment	1/1/2022	18	11/17/2020	NTC
Columbus East 230/115 kV transformer replacement	1/1/2039	24	1/1/2037	No
Franks-South Crocker-Lebanon 161 kV terminal equipment	1/1/2028	18	7/1/2026	No
Tap Woodward-Border 345 kV, Chisholm-Tap 345 kV new line	1/1/2022	48	11/17/2020	NTC-C
Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment	1/1/2022	18	11/17/2020	NTC
Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in	1/1/2025	48	1/1/2021	NTC-C
Split Rock 345/115 kV circuit 10 and 11 terminal equipment	1/1/2025	18	7/1/2023	No
Oahe-Sully Buttes-Whitlock 230 kV terminal equipment[40]	1/1/2028	18	7/1/2026	No
Deaf Smith #6-Hereford 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Deaf Smith #6-Friona 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Cargill-Friona 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Cargill-Deaf Smith #24 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Parmer-Deaf Smith #24 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Parmer-Deaf Smith #20 115 kV rebuild	4/1/2022	24	11/17/2020	NTC
Curry-Deaf Smith #20 115 kV rebuild	4/1/2022	24	11/17/2020	No

Table 9.1: NTC Recommendations

---

[40] Information in this table includes considerations of the updated cost estimate.

10 GLOSSARY

Acronym	Name
ABB	ABB Group licenses the PROMOD enterprise software SPP uses for economic simulations
APC	Adjusted production cost = Production Cost $ + Purchases $-Sales $
ARR	Auction Revenue Rights
ATC	Available transfer capacity
BAA	Balancing Authority Area
BAU	Business as usual
B/C	Benefit-to-Cost Ratio
BES	Bulk-Electric System
CC	Combined cycle
CLR	Cost per loading relief
CT	Combustion turbine
CVR	Cost per voltage relief
DPP	Detailed Project Proposal
E&C	Engineering and construction cost
ERCOT	Electric Reliability Council of Texas (ERCOT)
EHV	Extra-high voltage
ESWG	Economic Studies Working Group
FCITC	First contingency incremental transfer capacity
FERC	Federal Energy Regulatory Commission
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GOF	Generator outlet facilities
GW	Gigawatt
GWh	Gigawatt hour
HV	High voltage
IFTS	Interruption of firm transmission service
IRP	Integrated resource plan

Acronym	Name
IS	Integrated System, which includes the Western Area Power Administration's Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative, and the Heartland Consumers Power District
ITP	Integrated Transmission Planning
ITP Manual	Integrated Transmission Planning Manual
kV	Kilovolt
LMP	Locational Marginal Price = the market-clearing price for energy at a given Price Node equivalent to the marginal cost of serving demand at the Price Node, while meeting SPP Operating Reserve requirements
MISO	Midcontinent Independent System Operator
MTEP19	2019 MISO Transmission Expansion Plan
MTEP20	2020 MISO Transmission Expansion Plan
MTEP	MISO Transmission Expansion Plan
MDWG	Model Development Working Group
MMWG	Multi-regional Modeling Working Group
MOPC	Markets and Operations Policy Committee
MW	Megawatt
NERC	North American Electric Reliability Corporation
NITSA	Network Integration Transmission Service Agreement
NPV	Net present value
NREL	National Renewable Energy Laboratory
NCLL	Non-consequential load loss
NTC	Notification to Construct
PPA	Power Purchase Agreement
PST	Phase-shifting transformer
RCAR	Regional Cost Allocation Review
RPS	Renewable portfolio standards
SASK	Saskatchewan Power
SPC	Strategic Planning Committee
SPP OATT	SPP Open Access Transmission Tariff
TO	Transmission Owner
TSR	Transmission Service Request

Acronym	Name
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
US EIA	United States Energy Information Administration
VSL	Voltage stability limit

Table 10.1: Glossary

Project Name	Upgrade Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Project Status	From Bus Name	To Bus Name	Project Description/ Comments	Voltages (kV)
Line - Carlisle - Wolfforth 230 kV	Carlisle Interchange - Wolfforth Interchange 230 kV Ckt 1	Regional Reliability	3/27/2018	6/1/2017	Complete	Wolfforth Interchange 230 kV	Carlisle Interchange 230 kV	Build new 16.8-mile 230 kV line from Carlisle to Wolfforth South and install necessary terminal equipment.	230
Multi - Centre St. - Hereford NE 115 kV Ckt 1 and Centre St. and Hereford 115 kV Load Conversion	Centre St. - Hereford NE 115 kV Ckt 1	Regional Reliability	4/6/2018	6/1/2014	Complete	Northeast Hereford Interchange 115 kV	Hereford Centre Street Sub	Build new 5.1-mile 115 kV line from Centre St. to Hereford NE. Convert distribution transformer high side at Centre St. from 69 kV to 115 kV. Install any necessary terminal equipment at Hereford NE.	115
Line - Soncy convert load to 115 kV	Soncy Tap 115 kV - New Soncy 115 kV	Regional Reliability	12/31/2018	6/1/2015	Complete	Soncy Tap 115 kV	New Soncy 115 kV	Convert 1.04 miles of Z33 to 115 kV service by tapping the 115 kV line from Sunset Substation to Coulter Interchange at I-40 & Soncy Street. At Soncy Sub split the converted Z33 line off the 69 kV bus and terminate to a new 115/13.2 kV transformer to serve the Soncy distribution load. Install new 115/13.2 kV distribution transformer. Leave 69 kV underground cable to Lawrence Park to be fed by Y72 out of Coulter Interchange.	115
Line - Allen Sub - Lubbock South Interchange 115 kV Ckt 1	Allen Substation - Lubbock South Interchange 115 kV Ckt 1	Regional Reliability	4/26/2019	6/1/2019	Complete	Lubbock South Interchange 115 kV	Allen Sub 115 kV	Rebuild 6-mile 115 kV line from Lubbock South Interchange to Allen substation.	115
Line - Canyon East - Randall 115 kV Ckt 1 Rebuild	Canyon East Sub - Randall County Interchange 115 kV Ckt 1 Rebuild	Regional Reliability	3/20/2020	2/1/2014	Complete	Randall County Interchange 115 kV	Canyon East Sub 115 kV	Rebuild 13.5-mile 4/0 segment of 115 kV line from Canyon East Sub to Randall County Interchange.	115
Multi - Tuco - Yoakum 345/230 kV Ckt 1	Tuco - Yoakum 345 kV Ckt 1	Regional Reliability	6/1/2020	6/1/2017	Complete	TUCO Interchange 345 kV		Construct new 107-mile 345 kV line from Tuco to Yoakum. Install any necessary 345 kV terminal equipment at Yoakum associated with new 345/230 kV transformer.	345
Multi - Tuco - Yoakum 345/230 kV Ckt 1	Yoakum 345/230 kV Ckt 1 Transformer	Regional Reliability	5/31/2019	6/1/2017	Complete		Amoco Switching Station 230 kV (Amoco Slaughter)	Install new 345/230 kV 640 MVA transformer at Yoakum substation. Install any necessary 230 kV terminal equipment.	345/230
Multi - Hobbs - Yoakum 345/230 kV Ckt 1	Hobbs - Yoakum 345 kV Ckt 1	High Priority	5/30/2019	6/1/2020	Complete		Hobbs Interchange 345 kV	Construct new 52-mile 345 kV line from Hobbs to Yoakum.	345
Device - Cochran 115 kV Cap Bank	Cochran 115 kV Cap Bank	Regional Reliability	12/31/2018	6/1/2016	Complete	Cochran Interchange 115 kV		Install 28.8-MVAR capacitor bank at Cochran 115 kV (two 14.4-MVAR stages).	115
Line - Atoka - Eagle Creek 115 kV Ckt 1	Atoka - Eagle Creek 115 kV Ckt 1	Regional Reliability	12/31/2018	6/1/2015	Complete	Atoka Interchange 115 kV	Eagle Creek 115 kV	Build new 12-mile 115 kV line from Atoka to Eagle Creek and install necessary terminal equipment.	115
Multi - Kilgore Switch - South Portales - Market St. - Portales 115 kV	Market St. - South Portales 115 kV Ckt 1	Regional Reliability	7/13/2018	6/1/2018	Complete	S Portales 115 kV	Market ST 115 kV	Build new 6-mile 115 kV line from South Portales to Market St. and install necessary terminal equipment.	115
Multi - Kilgore Switch - South Portales - Market St. - Portales 115 kV	Market St. - Portales 115 kV Ckt 1	Regional Reliability	2/7/2018	6/1/2018	Complete	Market ST 115 kV	Portales Interchange 115 kV	Build new 10.4-mile 115 kV line from Market St. to Portales and install necessary terminal equipment.	115
Line - Mustang - Shell CO2 115 kV Ckt 1	Mustang - Shell CO2 115 kV Ckt 1	Transmission Service	4/29/2019	6/1/2015	Complete	Mustang Interchange North Bus 115 kV	Shell Co2 Gas Sub 115 kV	Construct new 7.7-mile 115 kV line from Mustang to Shell CO2.	115
Line - Chavis - Price - CV Pines - Capitan 115 kV Ckt 1	CV Pines - Price 115 kV Ckt 1 Rebuild	Regional Reliability	1/30/2018	6/1/2017	Complete	PRICE 3 115 kV	CV-PINES 3 115 kV	Rebuild 3-mile 69 kV line from CV Pines to Price converting to 115 kV.	115

Project Name	Upgrade Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Project Status	From Bus Name	To Bus Name	Project Description/ Comments	Voltages (kV)
Line - Chavis - Price - CV Pines - Capitan 115 kV Ckt 1	Capitan - CV Pines 115 kV Ckt 1 Rebuild	Regional Reliability	1/30/2018	6/1/2017	Closed Out	CV-PINES 3 115 kV	Capitan 115 kV	Rebuild 5-mile 69 kV line from Capitan to CV Pines converting to 115 kV.	115
Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	Kiowa - North Loving 345 kV Ckt 1	High Priority	6/1/2018	6/1/2018	Complete			Construct new 20.4-mile 345 kV line from new Kiowa substation to North Loving.	345
Multi - China Draw - Yeso Hills 115 kV	China Draw - Yeso Hills 115 kV Ckt 1	High Priority	5/3/2019	6/1/2018	Complete	China Draw 115 kV		Construct new 18.4-mile 115 kV line from China Draw to new Yeso Hills substation.	115
Multi - Potash Junction - Road Runner 345 kV Conv. and Transformers at Kiowa and Road Runner	Kiowa - Potash Junction 345/115 kV Ckt 1	High Priority	4/30/2018	6/1/2018	Complete		Road Runner 345 kV	Construct 1-mile of double circuit structures from the new Kiowa substation to Potash Junction. Construct Circuit 1 with 345 kV conductor and Circuit 2 with 115 kV conductor.	345
Multi - Ponderosa - Ponderosa Tap 115 kV	Ponderosa 115 kV Substation	High Priority	6/1/2017	6/1/2018	Closed Out			Construct new 115 kV Ponderosa substation. Install any necessary 115 kV terminal equipment.	115
Multi - Ponderosa - Ponderosa Tap 115 kV	Ponderosa Tap 115 kV Substation	High Priority	6/1/2017	6/1/2018	Closed Out			Tap the existing 115 kV line from Ochoa to Whitten to construct new 115 kV Ponderosa Tap substation. Install any necessary 115 kV terminal equipment.	115
Line - Hopi Sub - North Loving - China Draw 115 kV Ckt 1	China Draw - North Loving 115 kV Ckt 1	High Priority	5/25/2015	6/1/2015	Closed Out	North Loving 115 kV	China Draw 115 kV	Construct new 19.7-mile 115 kV line from North Loving to China Draw.	115
XFR - Seminole 230/115 kV #1 and #2	Seminole 230/115 kV #1 Transformer	Regional Reliability	12/28/2018	6/1/2017	Complete	Seminole Interchange 230 kV	Seminole Interchange 115 kV	Replace first existing 230/115 transformer at Seminole.	230/115
XFR - Seminole 230/115 kV #1 and #2	Seminole 230/115 kV #2 Transformer	Regional Reliability	4/30/2019	6/1/2017	Complete	Seminole Interchange 230 kV	Seminole Interchange 115 kV	Replace second existing 230/115 transformer at Seminole.	230/115
XFR - Wolfforth 230/115 kV Ckt 1 Transformer	Wolfforth 230/115 kV Ckt 1 Transformer	Regional Reliability	4/15/2021	6/1/2021	On Schedule < 4	Wolfforth Interchange 230 kV	Wolfforth Interchange 115 kV	Replace 230/115 kV transformer at Wolfforth substation.	230/115
Multi - Ponderosa - Ponderosa Tap 115 kV	Ponderosa - Ponderosa Tap 115 kV Ckt 1	High Priority	6/1/2017	6/1/2018	Closed Out			Construct new 9.3-mile 115 kV line from new Ponderosa substation to new Ponderosa Tap substation.	115
Line - Northwest - Rolling Hills 115 kV Ckt 1	Northwest - Rolling Hills 115 kV Rebuild Ckt 1	Regional Reliability	5/15/2021	6/1/2021	On Schedule < 4		Northwest Interchange 115 kV	Rebuild 8.3-mile 115 kV line from Northwest to Rolling Hills.	115
Multi - Road Runner 115 kV Loop Rebuild	IMC #1 Tap - Livingston Ridge 115 kV Ckt 1 Rebuild	Regional Reliability	3/22/2019	6/1/2015	Complete	I. M. C. #1 Sub Tap 115 kV (International Mineral Co)		Rebuild 9.5-mile 115 kV line from Livingston Ridge to IMC #1 Tap.	115
Multi - Road Runner 115 kV Loop Rebuild	Ponderosa Tap - Whitten 115 kV Ckt 1 Rebuild	Regional Reliability	1/26/2018	6/1/2015	Complete		Whitten Sub 115 kV	Reconductor 5.9-mile 115 kV line from Ponderosa Tap to Whitten.	115
Multi - Road Runner 115 kV Loop Rebuild	Intrepid West - Potash Junction 115 kV Ckt 1 Rebuild	Regional Reliability	3/22/2019	6/1/2015	Complete		Potash Junction Interchange 115 kV	Rebuild 1.5-mile 115 kV line from Intrepid West Tap to Potash Junction.	115
Multi - Road Runner 115 kV Loop Rebuild	IMC #1 Tap - Intrepid West 115 kV Ckt 1 Rebuild	Regional Reliability	3/22/2019	6/1/2015	Complete		I. M. C. #1 Sub Tap 115 kV (International Mineral Co)	Rebuild 3.9-mile 115 kV line from Intrepid West Tap to IMC #2.	115
Multi - Battle Axe - Road Runner 115 kV	Battle Axe 115 kV Substation	High Priority	12/4/2015	6/1/2018	Closed Out			Construct new 115 kV Battle Axe substation. Install any necessary 115 kV terminal equipment.	115
Multi - China Draw - Yeso Hills 115 kV	Yeso Hills 115 kV Substation	High Priority	5/3/2019	6/1/2018	Complete			Construct new 115 kV Yeso Hills substation. Install any necessary 115 kV terminal equipment.	115

Project Name	Upgrade Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Project Status	From Bus Name	To Bus Name	Project Description/ Comments	Voltages (kV)
XFR - Tuco 230/115 kV Ckt 1	Tuco 230/115 kV Ckt 1 Transformer	Transmission Service	6/15/2019	6/1/2018	Complete	TUCO Interchange 230 kV	TUCO Interchange 115 kV	Upgrade 230/115 kV transformer at Tuco to 273 MVA.	230/115
XFR - Yoakum County Interchange 230/115 kV Ckts 1 and 2	Yoakum County Interchange 230/115 kV Ckt 1 Transformer	Transmission Service	3/15/2019	6/1/2019	Complete	Yoakum County Interchange 230 kV	Yoakum County Interchange 115 kV	Upgrade Yoakum County Interchange Ckt 1 230/115 kV transformer to 250 MVA.	230/115
XFR - Yoakum County Interchange 230/115 kV Ckts 1 and 2	Yoakum County Interchange 230/115 kV Ckt 2 Transformer	Regional Reliability	5/7/2019	6/1/2019	Complete	Yoakum County Interchange 230 kV	Yoakum County Interchange 115 kV	Upgrade Yoakum County Interchange Ckt 2 230/115 kV transformer to 250 MVA.	230/115
Sub - Amoco - Sundown 230 kV Terminal Upgrades	Amoco - Sundown 230 kV Terminal Upgrades	Regional Reliability	2/20/2019	1/1/2019	Complete	Sundown Interchange 230 kV	Amoco Switching Station 230 kV (Amoco Slaughter)	Upgrade switches and wave traps at Sundown and Amoco and increase the line clearance to increase the rating of the 230 kV line from Amoco to Sundown.	230
Sub - Amarillo South 230 kV Terminal Upgrades	Amarillo South 230 kV Terminal Upgrades	Regional Reliability		4/1/2020	On Schedule < 4	Amarillo South Interchange 230 kV	Swisher County Interchange 230 kV	Replace wave trap at Amarillo South to increase the rating of the 230 kV line from Amarillo South to Swisher County.	230
XFR - Lynn County 115/69 kV Ckt 1 Transformer	Lynn County 115/69 kV Ckt 1 Transformer	Regional Reliability	5/15/2019	6/1/2019	Complete	Lynn County Interchange 115 kV	Lynn County Interchange 69 kV	Replace 115/69 kV transformer at Lynn County substation.	115/69
Multi - Walkemeyer Tap - Walkemeyer 345/115 kV	Stevens Co. 345 kV Substation	Regional Reliability	6/1/2018	6/1/2015	Complete	Walkemeyer Tap 345 kV		Tap the existing 345 kV line from Finney to Hitchland to construct the new Stevens Co. substation. Install any necessary 345 kV terminal equipment.	345
Multi - Road Runner 115 kV Loop Rebuild	National Enrichment Plant - Targa 115 kV Ckt 1	Regional Reliability	3/20/2019	6/1/2015	Complete	National Enrichment Plant Sub 115 kV	Whitten Sub 115 kV	Rebuild 4.3-mile 115 kV line from National Enrichment Plant to Targa.	115
XFR - Lynn County 115/69 kV Ckt 1 Transformer	Lynn County 115 kV Terminal Upgrades	Regional Reliability	5/15/2019	6/1/2019	Complete	Lynn County Interchange 115 kV		Install 115 kV terminal equipment at Lynn County substation necessary to replace 115/69 kV transformer.	115
Line - Cochran - Whiteface Tap 69 kV Ckt 1 Rebuild	Cochran - Whiteface Tap 69 kV Ckt 1 Rebuild	Regional Reliability	11/28/2018	6/1/2016	Complete			Rebuild 4.5-mile 69 kV line from Cochran to Whiteface Tap to 115 kV standards (operated at 69 kV).	69
Line - Cunningham - Monument Tap 115 kV Ckt 1 Rebuild	Cunningham - Monument Tap 115 kV Ckt 1 Rebuild	Regional Reliability	12/20/2019	6/1/2021	Complete	Cunningham Station 115 kV	Monument Tap 115 kV	Rebuild 6.5-mile 115 kV line from Cunningham to Monument Tap.	115
Sub - Eddy Co. 230 kV Bus Tie	Eddy Co. 230 kV Bus Tie	Transmission Service	12/20/2019	10/1/2017	Complete	Eddy County Interchange 230 kV		Reconfigure 230 kV bus tie at Eddy Co. substation to convert to a double bus and breaker scheme.	230
Sub - Potash Junction 230 kV Terminal Upgrade	Potash Junction 230 kV Terminal Upgrade	Regional Reliability	6/1/2018	6/1/2018	Complete	Potash Junction Interchange 230 kV		Replace wavetrap at Potash Junction 230 kV substation.	230
Line - National Enrichment Plant - Teague 115 kV Ckt 1 Rebuild	National Enrichment Plant - Teague 115 kV Ckt 1 Rebuild	Regional Reliability	12/14/2018	6/1/2018	Complete	National Enrichment Plant Tap 115 kV	Teague Sub 115 kV	Rebuild 6.8-mile 115 kV line from National Enrichment Plant to Teague.	115
Sub - Potter Co. - Harrington 230 kV Terminal Upgrades	Potter Co. - Harrington 230 kV Terminal Upgrades	Regional Reliability	5/16/2019	6/1/2019	Complete	Potter County Interchange 230 kV	Harrington Station East Bus 230 kV	Upgrade terminal equipment at both Potter Co. and Harrington 230 kV substations.	230
Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	Agave Red Hills - Road Runner 115 kV Ckt 1 New Line	Regional Reliability	3/20/2017	4/1/2020	Complete		Road Runner 115 kV	Construct new 115 kV line from Agave Red Hills to Road Runner.	115

Project Name	Upgrade Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Project Status	From Bus Name	To Bus Name	Project Description/ Comments	Voltages (kV)
Line - Road Runner - Agave Red Hills/Ochoa/Custer Mountain 115 kV New Line	Custer Mountain - Road Runner 115 kV Ckt 1 New Line	Regional Reliability	4/28/2017	4/1/2020	Complete		Road Runner 115 kV	Add new 1-mile segment to existing 115 kV line from Custer Mountain to Ochoa, re-terminating at Road Runner.	115
XFR - Sundown 230/115 kV Transformer	Sundown 230/115 kV Transformer	Regional Reliability	12/15/2020	6/1/2019	Closed Out	Sundown Interchange 230 kV	Sundown Interchange 115 kV	Upgrade the existing 230/115 kV transformer at Sundown and replace any terminal equipment required to meet the full rating of the new transformer.	230/115
Multi - Artesia County 115 kV	Artesia Country Club Tap 115 kV Line Tap	Regional Reliability	12/17/2018	6/1/2017	Complete	Eagle Creek 115 kV	Atoka Interchange 115 kV	Tap the 115 kV line from Atoka to Eagle Creek and install 3-way switch at tap point.	115
Line - Mustang - Seminole 115 kV Ckt 1 New Line	Mustang - Seminole 115 kV Ckt 1 New Line	Regional Reliability	12/15/2020	6/1/2017	Closed Out	Mustang Interchange North Bus 115 kV	Seminole Interchange 115 kV	Construct new 115 kV line from Mustang to Seminole.	115
Line - Mustang - Seminole 115 kV Ckt 1 New Line	Mustang 115 kV Terminal Upgrades	Regional Reliability	12/15/2020	6/1/2017	Closed Out	Mustang Interchange North Bus 115 kV		Install terminal upgrades at Mustang 115 kV substation needed to accommodate termination of new line from Seminole.	115
Line - Mustang - Seminole 115 kV Ckt 1 New Line	Seminole 115 kV Terminal Upgrades	Regional Reliability	12/15/2020	6/1/2017	Closed Out	Seminole Interchange 115 kV		Install terminal upgrades at Seminole 115 kV substation needed to accommodate termination of new line from Mustang.	115
Line - Canyon East Tap - Randall 115 kV Ckt 1 Rebuild	Canyon East Tap - Randall 115 kV Ckt 1 Rebuild	Regional Reliability	5/16/2019	6/1/2017	Complete	Canyon East Sub 115 kV	Randall County Interchange 115 kV	Rebuild 3-mile segment of 115 kV line from Canyon East Tap to Randall.	115
Sub - Terry Co. - Wolfforth 115 kV Terminal Upgrades	Terry Co. - Wolfforth 115 kV Terminal Upgrades	Regional Reliability	6/1/2018	4/1/2020	Complete	Terry County Interchange 115 kV	Wolfforth Interchange 115 kV	Upgrade terminal equipment at Terry Co. and Wolfforth to increase the rating of the 115 kV line from Terry Co. to Wolfforth.	115
Line - Livingston Ridge - Wipp 115 kV Ckt 1 Rebuild	Livingston Ridge - Wipp 115 kV Ckt 1 Rebuild	Regional Reliability	4/15/2021	6/1/2021	On Schedule < 4	Livingston Ridge Sub 69 kV	WIPP Sub 115 kV	Rebuild 2.8-mile 115 kV line from Livingston Ridge to Wipp.	115
Sub - Carlsbad - Pecos 115 kV Terminal Upgrades	Carlsbad - Pecos 115 kV Terminal Upgrades	Regional Reliability	6/1/2021	6/1/2021	On Schedule < 4	Carlsbad Interchange 115 kV	Pecos Interchange 115 kV	Install terminal upgrades at Carlsbad and/or Pecos to increase the rating of the 115 kV line between the substations.	115
SUB - TUCO 230kV Switching Station GEN-2012-020 Addition	TUCO 230kV Switching Station GEN-2012-020 Addition (TOIF)	Generation Interconnection	12/14/2018		On Schedule < 4			TUCO 230kV Switching Station: Communications; Revenue Metering; 230kV Line arrestors.	
Sub - Tuco - Stanton 115 kV Terminal Upgrades	Tuco - Stanton 115 kV Terminal Upgrades	Economic	12/31/2018	1/1/2017	In Service	TUCO Interchange 115 kV	Stanton Sub 115 kV	Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115 kV line between the two substations.	115
Sub - Indiana - SP-Erskine 115 kV Terminal Upgrades	Indiana - SP-Erskine 115 kV Terminal Upgrades	Economic	2/28/2020	1/1/2017	Delay - Mitigation	Indiana Sub 115 kV	South Plains REC-Erskine 115 kV	Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115 kV line between the two substations.	115
Line - Cox Interchange - Hale Co Interchange 115 kV Rebuild	Cox Interchange - Hale Co Interchange 115 kV Ckt 1	Regional Reliability	4/15/2021	6/1/2021	On Schedule < 4			Rebuild 19.88 miles of 115 kV transmission line from Cox Interchange to Hale Co Interchange.	115
Sub - Hockley County Interchange 115 kV Terminal Upgrades	Hockley County Interchange 115 kV Terminal Upgrades	Regional Reliability	11/15/2019	6/1/2021	Complete			Replace wave trap at Hockley County Interchange to increase the line capacity for Hockley County Interchange - Lamb County Interchange 115 kV Ckt 1.	115

Project Name	Upgrade Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Project Status	From Bus Name	To Bus Name	Project Description/ Comments	Voltages (kV)
Sub - Martin - Pantex N 115 kV Terminal Upgrades	Martin - Pantex North 115 kV Terminal Upgrades	Economic	3/15/2018	1/1/2017	Complete	Martin Sub 115 kV	Pantex North Sub 115 kV	Upgrade any necessary terminal equipment at Martin and/or Pantex North to increase the rating of the 115 kV line between the two substations.	115
Sub - Martin - Pantex N 115 kV Terminal Upgrades	Pantex South - Highland Tap 115 kV Terminal Upgrades	Economic	3/15/2018	1/1/2017	Complete	Pantex South Sub 115 kV	Highland Park Tap 115 kV	Upgrade any necessary terminal equipment at Pantex South and/or Highland Tap to increase the rating of the 115 kV line between the two substations.	115
Sub - Coulter 115 kV	Coulter 115 kV Terminal Upgrades	Regional Reliability	5/15/2020	6/1/2018	Closed Out	Coulter Interchange 115 kV		Install terminal upgrades on the 115 kV circuit W71 (Coulter - Puckett) at Coulter Substation.	115
Sub - Plant X - Sundown 230 kV	Plant X 230 kV Terminal Upgrades	Regional Reliability	12/31/2018	6/1/2018	Delay - Mitigation	Plant X Station 230 kV		Install terminal upgradeson the 230 kV circuit K46 (Plant X - Sundown) at Plant X.	230
Sub - Plant X - Sundown 230 kV	Sundown 230 kV Terminal Upgrades	Regional Reliability	12/31/2018	6/1/2018	Delay - Mitigation	Sundown Interchange 230 kV		Install terminal upgrades on the 230 kV circuit K46 (Plant X - Sundown) at Sundown.	230
Terry County - LG Clauene 115 kV Terminal Upgrades	Terry County - LG Clauene 115 kV Terminal Upgrades	Regional Reliability	12/31/2019	6/1/2019	Complete	Lyntegar REC-Clauene 115 kV		Replace terminal equipment on the Clauene-Terry (circuit V55) line and address any line clearance concerns to meet or exceed the line's conductor rating.	115
Sub - Texas County - Hitchland 115 kV bus	Texas County 115 kV Terminal Upgrades #1	Regional Reliability	12/31/2018	6/1/2018	Delay - Mitigation	Texas County Interchange 115 kV	Hitchland Interchange 115 kV	Upgrade terminal equipment on the Texas County - Hitchland 115 kV Ckt 1 at Texas County.	115
Sub - Texas County - Hitchland 115 kV bus	Texas County 115 kV Terminal Upgrades #2	Regional Reliability	12/31/2018	6/1/2018	Delay - Mitigation	Texas County Interchange 115 kV	Hitchland Interchange 115 kV	Upgrade terminal equipment on the Texas County - Hitchland 115 kV Ckt 2 at Texas County.	115
Sub - Nichols - 230 kV	Nichols 230 kV Terminal Upgrades	Regional Reliability	5/15/2020	12/1/2018	Closed Out	Nichols Station 230 kV	Amarillo South Interchange 230 kV	Install terminal upgrades on the Nichols - Amarillo 230 kV circuit at Nichols.	230
Line - Etter - Moore - 115 kV	Etter - Moore 115 kV Rebuild	Regional Reliability	12/15/2021	6/1/2018	Delay - Mitigation	Moore County Interchange East Bus 115 kV	Etter Rural Sub 115 kV	Rebuild 10.83-mile 115 kV line from Etter to Moore.	115
Carlisle - Murphy 115kV Terminal Upgrades	Carlisle - Murphy 115 kV Terminal Upgrades	Regional Reliability	3/11/2022	6/1/2022	On Schedule < 4	Carlisle Interchange 115 kV	Murphy Sub 115 kV	Replace terminal equipment on the Carlisle to Murphy (circuit V40) line and address any line clearance concerns to meet or exceed the conductor rating.	115
XFR - McDowell 230/115 kV Ckt 1	McDowell Creek 230/115kV Substation	Regional Reliability	4/16/2022	6/1/2019	Delay - Mitigation			Tap Moore-Potter 230kV and tap Exell-Fain 115kV and tie into a new substation at McDowell Creek.	230
XFR - McDowell 230/115 kV Ckt 1	McDowell Creek 230/115kV Transformer	Regional Reliability	4/16/2022	6/1/2019	Delay - Mitigation			Install a 230/115 kV transformer at the McDowell Creek substation	230/115
Multi - China Draw - Road Runner 345 kV	Bopco - Road Runner 345 kV Ckt 1 New Line	Regional Reliability	11/15/2021	12/1/2018	Delay - Mitigation		Road Runner 345 kV	Build new 21 mile 345 kV line from Bopco to Road Runner.	345
Multi - China Draw - Road Runner 345 kV	Bopco - China Draw 345 kV Ckt 1 New Line	Regional Reliability	11/15/2021	12/1/2021	On Schedule < 4			Build new 19 mile 345 kV line from Bopco to China Draw.	345
Multi - China Draw - Road Runner 345 kV	Bopco 345/115 kV Ckt 1 Transformer	Regional Reliability	11/15/2021	12/1/2018	Delay - Mitigation			Construct 345/115 kV transformer at Bopco substation.	345/115
Multi - China Draw - Road Runner 345 kV	Bopco 345/115 kV Ckt 2 Transformer	Regional Reliability	11/15/2021	12/1/2021	On Schedule < 4			Construct second 345/115 kV transformer at Bopco substation.	345/115
Line - Eddy County - Kiowa 345 kV New Line	Eddy County - Kiowa 345 kV Ckt 1 New Line	Regional Reliability	11/3/2020	6/1/2024	Closed Out	Eddy County Interchange 345 kV		Build new 34 mile 345 kV line from Eddy County to Kiowa.	345
Multi - China Draw - Road Runner 345 kV	Bopco 345 kV Substation	Regional Reliability	11/15/2021	12/1/2018	Delay - Mitigation			Build 345 kV portion of new 345/115 kV Bopco substation.	345
Multi - China Draw - Road Runner 345 kV	Bopco 115 kV Substation	Regional Reliability	11/15/2020	12/1/2018	In Service			Build 115 kV portion of new 345/115 kV Bopco substation. This includes work to reterminate the Wood Draw - Red Bluff 115 kV line into the new substation.	115

Project Name	Upgrade Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Project Status	From Bus Name	To Bus Name	Project Description/ Comments	Voltages (kV)
Sub - Carlsbad Interchange 115 kV	Carlsbad Interchange 115 kV Breaker	Regional Reliability		6/1/2021	On Schedule < 4	Carlsbad Interchange 115 kV		Replace 1 breaker at Carlsbad Interchange 115 kV with 40 kA breakers	115
Sub - Hale Cty Interchange 115 kV	Hale County Interchange 115 kV Breakers	Regional Reliability	12/18/2020	6/1/2021	On Schedule < 4	Hale Co Interchange 115 kV		Replace 3 breakers at Hale County Interchange 115 kV with 40 kA breakers	115
Sub - Denver City Interchange 115 kV North	Denver City Interchange North 115 kV Breaker	Regional Reliability	3/15/2021	6/1/2021	On Schedule < 4	Denver City Interchange N. 115 kV		Replace 1 breaker at Denver City Interchange North 115 kV with 40 kA breaker	115
Sub - Denver City Interchange South 115 kV	Denver City Interchange South 115 kV Breakers	Regional Reliability	3/15/2021	6/1/2021	On Schedule < 4	Denver City Interchange S. 115 kV		Replace 2 breakers at Denver City Interchange South 115 kV with 40 kA breakers	115
Sub - Amoco - Sundown 115 kV	Amoco - Sundown 115kV Terminal Upgrades	Economic	6/1/2020	1/1/2023	Closed Out	Sundown Interchange 115 kV	Amoco Tap 115 kV	Upgrade any necessary terminal equipment at Sundown and/or Amoco Tap to increase the summer emergency rating to 175 MVA	115/115
Line - Hansford - Spearman 115kV	Hansford - Spearman 115 kV Rebuild	Economic	4/15/2021	1/1/2021	On Schedule < 4	Spearman Interchange 115 kV	Hansford County Switch Station 115 kV (POI: JD Wind #4 80MW)	Rebuild 1.2 miles of 115 kV line from Spearman to Hansford and replace structures at Hansford and/or Spearman as needed to increase the summer emergency rating to 233 MVA	115/115
Multi-Hobbs Interchange-Millen 115kV	Hobbs Interchange to Millen Rebuild 115 kV Ckt1	Regional Reliability	6/1/2022	6/1/2022	On Schedule < 4	Hobbs Interchange 115 kV	Millen Sub 115 kV	Rebuild 10.5 miles of Hobbs Interchange to Millen 115kV Line	
Multi-Hobbs Interchange-Millen 115kV	Johnson Draw 115 kV Capacitor Bank	Regional Reliability	6/1/2022	6/1/2022	On Schedule < 4	Johnson Draw 115 kV		New 28.8 MVAR capacitor bank addition at Johnson Draw 115kV	115
Line - Allen - Quaker 115kV	Allen - Quaker 115 kV Ckt 1 Rebuild	Regional Reliability		6/1/2022	On Schedule < 4	Allen Sub 115 kV	South Plains REC-Quaker 115 kV	Rebuild 3.6 miles 115 kV line from Allen to Quaker and upgrade any necessary terminal equipment to achieve a summer emergency rating of 300 MVA	
Line - Allen - Lubbock South 115kV	Allen - Lubbock South 115 kV Ckt 1 Rebuild	Regional Reliability		6/1/2022	On Schedule < 4	Allen Sub 115 kV	Lubbock South Interchange 115 kV	Rebuild 5.98 miles of 115 kV line from Allen to Lubbock and upgrade any necessary terminal equipment to achieve a summer emergency rating of 300 MVA.	
Sub - Bushland - Deaf Smith 230 kV	Bushland - Deaf Smith 230 kV Terminal Upgrades	Regional Reliability	4/15/2022	4/1/2022	Delay - Mitigation Window	Bushland Interchange 230 kV (POI: Wildorado Wind, 160MW)	Deaf Smith County Interchange 230 kV	Increase clearances and upgrade any necessary terminal equipment at Bushland and/or Deaf Smith 230 kV to achieve a summer emergency rating of 546 MVA.	
Sub - Newhart - Potter 230 kV	Newhart - Potter 230 kV Terminal Upgrades	Regional Reliability	12/15/2022	4/1/2022	On Schedule < 4	Newhart Interchange 230 kV	Potter County Interchange 230 kV	Increase clearances and upgrade any necessary terminal equipment at Newhart and/or Potter 230 kV to achieve a summer emergency rating of 540 MVA.	
Sub - Deaf Smith #6 - Friona 115 kV	Deaf Smith #6 - Friona 115 kV Rebuild	Regional Reliability	4/1/2022	4/1/2022	Delay - Mitigation Window	Deaf Smith REC-#6 115 kV	Friona Sub 115 kV	Rebuild 18.9 miles of 115 kV line from Deaf Smith #6 to Friona and upgrade any necessary terminal equipment at Deaf Smith #6 and/or Friona to achieve a summer emergency rating of 120 MVA	
Line - Carlisle - Murphy 115 kV #2	Carlisle - Murphy 115 kV Ckt 1 Rebuild	Regional Reliability	6/1/2022	6/1/2022	On Schedule < 4	Carlisle Interchange 115 kV	Murphy Sub 115 kV	Rebuild 4.0 miles of 115 kV line from Carlisle to Murphy and upgrade any necessary terminal equipment to achieve a summer emergency rating of 240 MVA	
Line - Deaf Smith #6 - Hereford 115 kV	Deaf Smith #6 - Hereford 115 kV Ckt 1 Rebuild	Regional Reliability	4/1/2022	4/1/2022	On Schedule < 4	Deaf Smith REC-#6 115 kV	Hereford Interchange 115 kV	Rebuild 2.33 miles of 115 kV line from Deaf Smith #6 to Hereford and upgrade any necessary terminal equipment to achieve a summer emergency rating of 239 MVA	

Project Name	Upgrade Name	Project Type	Project Owner Indicated In-Service Date	RTO Determined Need Date	Project Status	From Bus Name	To Bus Name	Project Description/ Comments	Voltages (kV)
Sub - Lubbock South - Wolfforth 230 kV	Lubbock South - Wolfforth 230 kV Ckt 1 Terminal Upgrades #2	Regional Reliability	6/1/2022	6/1/2022	On Schedule < 4	Lubbock South Interchange 230 kV	Wolfforth Interchange 230 kV	: Increase clearances and upgrade any necessary terminal equipment at Lubbock South and/or Wolfforth to achieve a summer emergency rating of 550 MVA	
Line - Cargill - Friona 115 kV	Cargill - Friona 115 kV Ckt 1 Rebuild	Regional Reliability		4/1/2022	On Schedule < 4			Rebuild 1.15 miles of existing 115 kV line from Cargill to Friona and upgrade any necessary terminal equipment to achieve a summer emergency rating of 240 MVA	
Line - Cargill - Deaf Smith #24 115 kV	Cargill - Deaf Smith #24 115 kV Ckt 1 Rebuild	Regional Reliability		4/1/2022	On Schedule < 4			Rebuild 7.74 miles of 115 kV line from Cargill to Deaf Smith #24 and upgrade any necessary terminal equipment to achieve a summer emergency rating of 240 MVA	
Line - Parmer - Deaf Smith #24 115 kV	Parmer - Deaf Smith #24 115 kV Ckt 1 Rebuild	Regional Reliability		4/1/2022	On Schedule < 4			Rebuild 1.16 miles of 115 kV line from Parmer - Deaf Smith #24 and upgrade any necessary terminal equipment to achieve a summer emergency rating of 240 MVA	
Line - Parmer - Deaf Smith #20 115 kV	Parmer - Deaf Smith #20 115 kV Ckt 1 Rebuild	Regional Reliability		4/1/2022	On Schedule < 4			Rebuild 7.6 miles of 115 kV line from Parmer - Deaf Smith #20 and upgrade any necessary terminal equipment to achieve a summer emergency rating of 240 MVA	

Q2 2021 Quarterly Project Tracking Appendix 1 - Project Status Definitions	
CLOSED OUT	Upgrade is operation, all project activities are complete, & all close-out requirements fulfilled
COMPLETE	Upgrade is operation and all project activities are complete
DELAY - MITIGATION	Behind schedule, interim mitigation provided or project may change but time permits the implementation of project; asterisk (*) indicates interim mitigation plan provided by SPP
IDENTIFIED	Upgrade identified and included in Board approved study results
IN SERVICE	Upgrade is in service, but not all project activities are complete
NTC - COMMITMENT WINDOW	NTC/NTC-C issued, still within the 90 day written commitment to construct window and no commitment received
NTC-C PROJECT ESTIMATE WINDOW	Within the NTC-C Project Estimate (CPE) window
ON SCHEDULE < 4	On Schedule within 4-year horizon
ON SCHEDULE > 4	On Schedule beyond 4-year horizon
RE-EVALUATION	NTC/NTC-C active; pending re-evaluation
RFP ISSUED	Request for proposal has been issued for competitive upgrade
RFP PENDING	Request for proposal issuance for a competitive upgrade is pending
SUSPENDED	NTC/GIA suspended

APPENDIX D – ELECTRIC ENERGY AND DEMAND FORECAST

- ***Current Load Forecast Tables:*** This appendix contains tables of the base case energy sales and coincident peak demand forecasts for each year within the planning period, 2022-2041:
  - Annual sales of energy and coincident peak demand on a system-wide basis;
  - Annual sales of energy and coincident peak demand by customer class;
  - Annual sales of energy and coincident peak demand disaggregated between Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states;
  - Annual Sales of Energy and Coincident Peak Demand by Retail and Wholesale Customer Class
  - Annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system;
  - Assumptions for economic and demographic factors relied on in load forecasting; and
  - Expected capacity and energy impacts of existing and proposed demand-side resources.
  - Annual Actual and Forecasted Firm Peak Demand for Base, and Forecasted Firm Peak Demand for Low and High Probable Scenario
  - Annual Actual and Forecasted Energy Sales for Base, and Forecasted Energy Sales for Low and High Probable Scenario
  - Annual Energy Sales Forecast Comparison
  - Annual Coincident Peak Demand Forecast Comparison
  - Annual Weather Normalized Firm Peak Demand Forecast Comparison

Table D-1: SPS's Base Case Energy Sales and Coincident Peak Demand Forecasts in the Context of the Last Twelve Years of History

	Energy Sales (GWh)	Annual Increase (GWh)	Peak Demand (MW)	Annual Increase (MW)
2010	27,935	568	4,951	(36)
2011	28,843	908	5,155	204
2012	26,614	(2,229)	5,145	(10)
2013	27,443	829	5,026	(119)
2014	26,162	(1,281)	4,844	(182)
2015	24,584	(1,578)	4,643	(201)
2016	24,678	93	4,800	157
2017	24,223	(455)	4,344	(456)
2018	25,433	1,210	4,618	274
2019	24,677	(756)	3,888	(730)
2020	23,082	(1,595)	3,748	(140)
2021	23,338	256	4,060	312
2022	23,731	393	3,969	(91)
2023	23,671	(60)	3,874	(94)
2024	23,748	77	3,899	24
2025	23,987	239	3,937	38
2026	23,772	(214)	3,867	(69)
2027	23,650	(123)	3,905	38
2028	23,808	159	3,934	29
2029	23,994	185	3,961	26
2030	24,145	151	3,982	21
2031	24,290	145	4,007	25
2032	24,451	161	4,033	26
2033	24,647	196	4,061	28
2034	24,849	202	4,085	24
2035	25,104	255	4,122	37
2036	25,267	163	4,153	31
2037	25,527	260	4,183	30
2038	25,722	196	4,207	24
2039	25,976	254	4,241	34
2040	26,212	235	4,275	35
2041	26,418	206	4,302	27

Table D-2: Forecasted Annual Sales of Energy and Coincident Peak Demand by Customer Class

	Energy Sales (GWh)					Coincident Peak Demand (MW)				
	Residential	Commercial & Industrial	Other	Resale	Total	Residential	Commercial & Industrial	Other	Resale	Total
2021	3,577	16,876	520	2,365	23,338	1,128	2,388	107	436	4,060
2022	3,582	17,632	514	2,003	23,731	1,142	2,417	109	301	3,969
2023	3,603	18,239	516	1,314	23,671	1,167	2,471	111	125	3,874
2024	3,618	18,742	514	874	23,748	1,183	2,503	113	100	3,899
2025	3,639	19,047	512	788	23,987	1,195	2,528	114	100	3,937
2026	3,669	19,262	509	333	23,772	1,204	2,548	115	-	3,867
2027	3,701	19,443	506	-	23,650	1,216	2,574	116	-	3,905
2028	3,742	19,565	502	-	23,808	1,225	2,593	117	-	3,934
2029	3,785	19,708	500	-	23,994	1,233	2,610	117	-	3,961
2030	3,830	19,818	497	-	24,145	1,240	2,624	118	-	3,982
2031	3,878	19,918	494	-	24,290	1,248	2,641	119	-	4,007
2032	3,942	20,019	490	-	24,451	1,256	2,658	120	-	4,033
2033	4,023	20,135	489	-	24,647	1,264	2,676	120	-	4,061
2034	4,124	20,239	486	-	24,849	1,272	2,692	121	-	4,085
2035	4,233	20,388	483	-	25,104	1,283	2,716	122	-	4,122
2036	4,348	20,439	479	-	25,267	1,293	2,737	123	-	4,153
2037	4,463	20,586	478	-	25,527	1,302	2,757	124	-	4,183
2038	4,579	20,669	475	-	25,722	1,310	2,772	125	-	4,207
2039	4,696	20,809	472	-	25,976	1,320	2,795	126	-	4,241
2040	4,810	20,933	469	-	26,212	1,331	2,817	127	-	4,275
2041	4,937	21,013	467	-	26,418	1,340	2,835	128	-	4,302

Table D-3: Forecasted Annual Sales of Energy and Coincident Peak Demand by Jurisdiction

	Energy Sales (GWh)				Coincident Peak Demand (MW)			
	Commission	FERC	Other States	Total	Commission	FERC	Other States	Total
2021	7,680	2,365	13,293	23,338	1,214	436	2,411	4,060
2022	8,242	2,003	13,486	23,731	1,228	301	2,439	3,969
2023	8,721	1,314	13,637	23,671	1,256	125	2,494	3,874
2024	9,189	874	13,685	23,748	1,272	100	2,526	3,899
2025	9,462	788	13,737	23,987	1,285	100	2,552	3,937
2026	9,660	333	13,779	23,772	1,295	-	2,572	3,867
2027	9,822	-	13,827	23,650	1,308	-	2,597	3,905
2028	9,932	-	13,877	23,808	1,318	-	2,617	3,934
2029	10,060	-	13,934	23,994	1,326	-	2,634	3,961
2030	10,153	-	13,992	24,145	1,333	-	2,648	3,982
2031	10,230	-	14,060	24,290	1,342	-	2,665	4,007
2032	10,309	-	14,141	24,451	1,351	-	2,682	4,033
2033	10,397	-	14,250	24,647	1,360	-	2,701	4,061
2034	10,474	-	14,374	24,849	1,368	-	2,717	4,085
2035	10,589	-	14,515	25,104	1,380	-	2,741	4,122
2036	10,617	-	14,650	25,267	1,391	-	2,762	4,153
2037	10,736	-	14,791	25,527	1,401	-	2,782	4,183
2038	10,790	-	14,933	25,722	1,409	-	2,798	4,207
2039	10,898	-	15,078	25,976	1,420	-	2,821	4,241
2040	10,988	-	15,223	26,212	1,432	-	2,844	4,275
2041	11,020	-	15,398	26,418	1,441	-	2,862	4,302

Table D-4: Historical and Forecasted Annual Sales of Energy and Coincident Peak Demand by Retail and Wholesale Customer Class

	Energy (GWh)			Peak (MW)		
	Retail Firm	Wholesale Firm	System Firm	Retail Firm	Wholesale Firm	System Firm
2010	18,575	9,359	27,935	3,361	1,590	4,951
2011	18,639	10,204	28,843	3,297	1,858	5,155
2012	18,532	8,082	26,614	3,378	1,767	5,145
2013	18,768	8,675	27,443	3,285	1,741	5,026
2014	19,108	7,055	26,162	3,316	1,531	4,847
2015	19,127	5,457	24,584	3,304	1,344	4,648
2016	19,259	5,419	24,678	3,436	1,370	4,806
2017	19,305	4,917	24,223	3,407	941	4,348
2018	20,450	4,982	25,433	3,590	1,032	4,622
2019	21,027	3,650	24,677	3,542	521	4,063
2020	20,574	2,508	23,082	3,507	417	3,924
2021	20,973	2,365	23,338	3,624	436	4,060
2022	21,728	2,003	23,731	3,668	301	3,969
2023	22,358	1,314	23,671	3,749	125	3,874
2024	22,874	874	23,748	3,799	100	3,899
2025	23,199	788	23,987	3,837	100	3,937
2026	23,440	333	23,772	3,867	0	3,867
2027	23,650	0	23,650	3,905	0	3,905
2028	23,808	0	23,808	3,934	0	3,934
2029	23,994	0	23,994	3,961	0	3,961
2030	24,145	0	24,145	3,982	0	3,982
2031	24,290	0	24,290	4,007	0	4,007
2032	24,451	0	24,451	4,033	0	4,033
2033	24,647	0	24,647	4,061	0	4,061
2034	24,849	0	24,849	4,085	0	4,085
2035	25,104	0	25,104	4,122	0	4,122
2036	25,267	0	25,267	4,153	0	4,153
2037	25,527	0	25,527	4,183	0	4,183
2038	25,722	0	25,722	4,207	0	4,207
2039	25,976	0	25,976	4,241	0	4,241
2040	26,212	0	26,212	4,275	0	4,275
2041	26,418	0	26,418	4,302	0	4,302

Table D-5: Forecasted Coincident Peak Demand System Losses (MW)

	Retail						
	Secondary Distribution	Primary Distribution	Sub-Transmission	Backbone Transmission	Total Retail	FERC	Total System
2021	281	62	4	22	369	29	399
2022	284	63	4	23	374	31	404
2023	290	64	4	23	382	30	412
2024	294	65	4	23	387	30	417
2025	297	66	4	24	391	16	407
2026	300	66	5	24	394	16	410
2027	302	67	5	24	398	17	415
2028	305	68	5	24	401	0	401
2029	307	68	5	24	404	0	404
2030	308	68	5	24	406	0	406
2031	310	69	5	25	408	0	408
2032	312	69	5	25	411	0	411
2033	315	70	5	25	414	0	414
2034	316	70	5	25	416	0	416
2035	319	71	5	25	420	0	420
2036	322	71	5	25	423	0	423
2037	324	72	5	26	426	0	426
2038	326	72	5	26	429	0	429
2039	328	73	5	26	432	0	432
2040	331	73	5	26	436	0	436
2041	333	74	5	26	439	0	439

Table D-6: Economic and Demographic Assumptions Used in Load Forecasting

Variable	Real Gross County Product - New Mexico Service Area		Real Gross County Product - Texas Service Area		Consumer Price Index		Real Personal Income - New Mexico Service Territory		Real Personal Income - Texas Service Territory	
Units	Millions of 2009 $	Pct Chg	Millions of 2009 $	Pct Chg	1982-84=1.00	Pct Chg	Millions of 2009 $	Pct Chg	Millions of 2009 $	Pct Chg
2021	24,469		42,035		2.65		13,801		25,747	
2022	25,503	4.2%	43,472	3.4%	2.72	2.6%	14,106	2.2%	26,332	2.3%
2023	26,286	3.1%	46,118	6.1%	2.78	2.2%	14,481	2.7%	27,189	3.3%
2024	26,761	1.8%	47,884	3.8%	2.84	2.1%	14,818	2.3%	27,769	2.1%
2025	27,187	1.6%	48,799	1.9%	2.90	2.2%	15,207	2.6%	28,369	2.2%
2026	27,902	2.6%	49,927	2.3%	2.96	2.3%	15,614	2.7%	29,044	2.4%
2027	28,754	3.1%	51,320	2.8%	3.04	2.4%	16,030	2.7%	29,734	2.4%
2028	29,768	3.5%	52,646	2.6%	3.11	2.5%	16,498	2.9%	30,411	2.3%
2029	30,625	2.9%	53,900	2.4%	3.19	2.4%	16,973	2.9%	31,059	2.1%
2030	31,396	2.5%	55,326	2.6%	3.26	2.4%	17,446	2.8%	31,727	2.2%
2031	31,981	1.9%	56,651	2.4%	3.34	2.3%	17,891	2.6%	32,348	2.0%
2032	32,586	1.9%	57,939	2.3%	3.42	2.3%	18,290	2.2%	32,993	2.0%
2033	33,156	1.7%	59,226	2.2%	3.50	2.3%	18,736	2.4%	33,662	2.0%
2034	33,763	1.8%	60,412	2.0%	3.58	2.4%	19,166	2.3%	34,326	2.0%
2035	34,332	1.7%	61,620	2.0%	3.67	2.4%	19,647	2.5%	35,010	2.0%
2036	34,853	1.5%	62,726	1.8%	3.75	2.4%	20,059	2.1%	35,700	2.0%
2037	35,437	1.7%	63,816	1.7%	3.84	2.4%	20,464	2.0%	36,331	1.8%
2038	36,091	1.8%	64,907	1.7%	3.93	2.4%	20,849	1.9%	36,918	1.6%
2039	36,703	1.7%	66,000	1.7%	4.03	2.4%	21,266	2.0%	37,488	1.5%
2040	37,289	1.6%	67,127	1.7%	4.12	2.4%	21,693	2.0%	38,070	1.6%
2041	37,870	1.6%	68,163	1.5%	4.22	2.4%	22,090	1.8%	38,658	1.5%

Table D-7: Economic and Demographic Assumptions Used in Load Forecasting (continued)

Variable	Non-farm Employment - New Mexico		Non-farm Employment - Texas		Real Gross Domestic Product		Household - Texas Service Territory		Household - New Mexico Service Territory	
Units	Thousands	Pct Chg	Thousands	Pct Chg	Billions of 2012 $	Pct Chg	Thousands	Pct Chg	Thousands	Pct Chg
2021	119		237		18,982		200		103	
2022	121	1.4%	240	1.2%	19,464	2.5%	201	0.7%	105	1.4%
2023	122	1.4%	244	1.5%	19,945	2.5%	202	0.6%	106	1.2%
2024	124	1.5%	246	1.0%	20,528	2.9%	203	0.6%	107	1.0%
2025	126	1.1%	248	0.6%	21,142	3.0%	204	0.5%	108	0.9%
2026	127	1.0%	249	0.5%	21,717	2.7%	206	0.7%	109	1.0%
2027	128	1.0%	250	0.4%	22,290	2.6%	207	0.7%	110	1.0%
2028	129	0.9%	251	0.3%	22,853	2.5%	208	0.6%	111	1.0%
2029	130	0.8%	251	0.3%	23,373	2.3%	210	0.6%	112	0.9%
2030	131	1.0%	252	0.4%	23,898	2.2%	211	0.7%	113	0.9%
2031	132	0.6%	253	0.4%	24,411	2.1%	213	0.7%	114	0.8%
2032	133	0.7%	255	0.6%	24,939	2.2%	214	0.7%	115	0.7%
2033	134	0.8%	256	0.6%	25,487	2.2%	216	0.7%	115	0.6%
2034	135	0.8%	258	0.6%	26,035	2.2%	217	0.6%	116	0.5%
2035	137	0.8%	259	0.6%	26,613	2.2%	218	0.6%	117	0.5%
2036	138	0.8%	261	0.6%	27,156	2.0%	219	0.5%	117	0.4%
2037	139	0.7%	262	0.5%	27,676	1.9%	220	0.4%	118	0.3%
2038	139	0.6%	263	0.4%	28,191	1.9%	221	0.4%	118	0.2%
2039	140	0.6%	264	0.4%	28,707	1.8%	222	0.4%	118	0.2%
2040	141	0.7%	265	0.5%	29,244	1.9%	223	0.3%	118	0.2%
2041	142	0.4%	266	0.3%	29,781	1.8%	224	0.3%	118	0.1%

Table D-8: Economic and Demographic Assumptions Used in Load Forecasting (continued)

Variable	Chained Price Index for Gross Domestic Product		Resident Population - New Mexico Service Territory		Resident Population - Texas Service Territory		Average Price of West Texas Intermediate Crude		Industrial production-- Oil and gas extraction	
Units	index 2012=100.0	Pct Chg	Thousands	Pct Chg	Thousands	Pct Chg	$ per barrel	Pct Chg	index 2012=100.0	Pct Chg
2021	115.82		272		564		43.91		122.80	
2022	118.15	2.0%	274	0.5%	564	0.0%	52.61	19.8%	126.42	2.9%
2023	120.60	2.1%	275	0.6%	565	0.2%	56.22	6.9%	129.10	2.1%
2024	123.12	2.1%	277	0.6%	566	0.2%	57.37	2.0%	131.83	2.1%
2025	125.71	2.1%	278	0.6%	567	0.2%	59.82	4.3%	134.95	2.4%
2026	128.44	2.2%	280	0.6%	569	0.3%	64.34	7.6%	139.10	3.1%
2027	131.39	2.3%	282	0.6%	571	0.4%	69.29	7.7%	141.64	1.8%
2028	134.52	2.4%	284	0.6%	573	0.4%	73.24	5.7%	142.62	0.7%
2029	137.74	2.4%	285	0.6%	575	0.4%	76.01	3.8%	143.10	0.3%
2030	141.05	2.4%	287	0.6%	578	0.4%	78.09	2.7%	143.33	0.2%
2031	144.30	2.3%	288	0.4%	580	0.4%	80.00	2.4%	143.43	0.1%
2032	147.60	2.3%	289	0.3%	582	0.4%	81.90	2.4%	144.50	0.7%
2033	150.97	2.3%	290	0.2%	584	0.4%	83.75	2.3%	144.30	-0.1%
2034	154.39	2.3%	290	0.2%	586	0.3%	85.64	2.3%	144.03	-0.2%
2035	157.89	2.3%	291	0.2%	588	0.3%	87.59	2.3%	145.12	0.8%
2036	161.44	2.2%	291	0.1%	589	0.2%	89.56	2.2%	146.39	0.9%
2037	165.03	2.2%	291	0.0%	590	0.2%	91.44	2.1%	146.81	0.3%
2038	168.72	2.2%	291	0.0%	591	0.2%	93.34	2.1%	146.96	0.1%
2039	172.48	2.2%	291	0.0%	592	0.1%	95.25	2.0%	147.36	0.3%
2040	176.37	2.3%	291	0.0%	593	0.1%	96.63	1.5%	147.28	-0.1%
2041	180.28	2.2%	291	-0.1%	593	0.1%	98.34	1.8%	146.91	-0.3%

Table D-9: Expected Capacity and Energy Impacts of Existing and Proposed Demand-Side Management Resources

	Existing Demand-Side Management Resources		Proposed Demand-Side Management Resources	
	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)
2021	58	13	6	1
2022	115	27	11	1
2023	173	40	17	1
2024	231	53	22	1
2025	288	66	27	1
2026	346	80	32	1
2027	404	93	37	1
2028	462	106	42	1
2029	519	119	47	2
2030	576	133	52	2
2031	634	146	57	2
2032	693	159	63	2
2033	749	172	68	2
2034	807	186	73	2
2035	830	191	81	3
2036	840	195	85	4
2037	847	198	88	4
2038	855	201	92	5
2039	863	204	95	6
2040	874	207	99	6
2041	872	207	98	6

Table D-10: Actual and Forecasted Firm Peak Demand

	MW			Annual Growth			Compound Growth to/from 2020		
	Base	Low	High	Base	Low	High	Base	Low	High
2010	4,951						-2.7%		
2011	5,155			4.1%			-3.5%		
2012	5,145			-0.2%			-3.9%		
2013	5,026			-2.3%			-4.1%		
2014	4,844			-3.6%			-4.2%		
2015	4,643			-4.1%			-4.2%		
2016	4,800			3.4%			-6.0%		
2017	4,344			-9.5%			0.0%		
2018	4,618			6.3%			11.0%		
2019	3,888			-15.8%			3.7%		
2020	3,748			-3.6%			0.0%		
2021	4,060	3,867	4,141	8.3%	3.2%	10.5%	8.3%	3.2%	10.5%
2022	3,969	3,709	4,133	-2.2%	-4.1%	-0.2%	2.9%	-0.5%	5.0%

Table D-10: Actual and Forecasted Firm Peak Demand (continued)

	MW			Annual Growth			Compound Growth to/from 2020		
2023	3,874	3,528	4,115	-2.4%	-4.9%	-0.4%	1.1%	-2.0%	3.2%
2024	3,899	3,507	4,207	0.6%	-0.6%	2.2%	1.0%	-1.6%	2.9%
2025	3,937	3,484	4,269	1.0%	-0.7%	1.5%	1.0%	-1.4%	2.6%
2026	3,867	3,363	4,240	-1.8%	-3.5%	-0.7%	0.5%	-1.8%	2.1%
2027	3,905	3,376	4,333	1.0%	0.4%	2.2%	0.6%	-1.5%	2.1%
2028	3,934	3,363	4,403	0.7%	-0.4%	1.6%	0.6%	-1.3%	2.0%
2029	3,961	3,343	4,464	0.7%	-0.6%	1.4%	0.6%	-1.3%	2.0%
2030	3,982	3,308	4,522	0.5%	-1.1%	1.3%	0.6%	-1.2%	1.9%
2031	4,007	3,332	4,565	0.6%	0.7%	1.0%	0.6%	-1.1%	1.8%
2032	4,033	3,312	4,652	0.6%	-0.6%	1.9%	0.6%	-1.0%	1.8%
2033	4,061	3,322	4,706	0.7%	0.3%	1.2%	0.6%	-0.9%	1.8%
2034	4,085	3,307	4,767	0.6%	-0.5%	1.3%	0.6%	-0.9%	1.7%
2035	4,122	3,295	4,799	0.9%	-0.4%	0.7%	0.6%	-0.9%	1.7%
2036	4,153	3,298	4,890	0.8%	0.1%	1.9%	0.6%	-0.8%	1.7%
2037	4,183	3,324	4,952	0.7%	0.8%	1.3%	0.6%	-0.7%	1.7%
2038	4,207	3,278	4,987	0.6%	-1.4%	0.7%	0.6%	-0.7%	1.6%
2039	4,241	3,270	5,066	0.8%	-0.2%	1.6%	0.7%	-0.7%	1.6%
2040	4,275	3,285	5,125	0.8%	0.5%	1.2%	0.7%	-0.7%	1.6%
2041	4,302	3,283	5,182	0.6%	-0.1%	1.1%	0.7%	-0.6%	1.6%

Table D-11: Actual and Forecasted Annual Energy Sales

	GWh			Annual Growth			Compound Growth to/from 2020		
	Base	Low	High	Base	Low	High	Base	Low	High
2010	27,935								
2011	28,843			3.3%			-2.1%		
2012	26,614			-7.7%			-2.7%		
2013	27,443			3.1%			-2.0%		
2014	26,162			-4.7%			-2.8%		
2015	24,584			-6.0%			-2.5%		
2016	24,678			0.4%			-1.6%		
2017	24,223			-1.8%			-2.2%		
2018	25,433			5.0%			-2.4%		
2019	24,677			-3.0%			-9.2%		
2020	23,082			-6.5%			0.0%		
2021	23,338	22,178	24,408	1.1%	-3.9%	5.7%	1.1%	-3.9%	5.7%
2022	23,731	21,941	25,451	1.7%	-1.1%	4.3%	1.4%	-2.5%	5.0%

Table D-11: Actual and Forecasted Annual Energy Sales (continued)

	GWh			Annual Growth			Compound Growth to/from 2020		
2023	23,671	21,362	25,878	-0.3%	-2.6%	1.7%	0.8%	-2.5%	3.9%
2024	23,748	20,946	26,452	0.3%	-1.9%	2.2%	0.7%	-2.4%	3.5%
2025	23,987	20,730	27,108	1.0%	-1.0%	2.5%	0.8%	-2.1%	3.3%
2026	23,772	20,186	27,282	-0.9%	-2.6%	0.6%	0.5%	-2.2%	2.8%
2027	23,650	19,696	27,519	-0.5%	-2.4%	0.9%	0.3%	-2.2%	2.5%
2028	23,808	19,522	27,996	0.7%	-0.9%	1.7%	0.4%	-2.1%	2.4%
2029	23,994	19,398	28,470	0.8%	-0.6%	1.7%	0.4%	-1.9%	2.4%
2030	24,145	19,206	28,929	0.6%	-1.0%	1.6%	0.5%	-1.8%	2.3%
2031	24,290	19,074	29,371	0.6%	-0.7%	1.5%	0.5%	-1.7%	2.2%
2032	24,451	18,913	29,807	0.7%	-0.8%	1.5%	0.5%	-1.6%	2.2%
2033	24,647	18,839	30,342	0.8%	-0.4%	1.8%	0.5%	-1.6%	2.1%
2034	24,849	18,762	30,882	0.8%	-0.4%	1.8%	0.5%	-1.5%	2.1%
2035	25,104	18,638	31,400	1.0%	-0.7%	1.7%	0.6%	-1.4%	2.1%
2036	25,267	18,466	31,885	0.6%	-0.9%	1.5%	0.6%	-1.4%	2.0%
2037	25,527	18,451	32,503	1.0%	-0.1%	1.9%	0.6%	-1.3%	2.0%
2038	25,722	18,304	32,996	0.8%	-0.8%	1.5%	0.6%	-1.3%	2.0%
2039	25,976	18,276	33,556	1.0%	-0.2%	1.7%	0.6%	-1.2%	2.0%
2040	26,212	18,155	34,137	0.9%	-0.7%	1.7%	0.6%	-1.2%	2.0%
2041	26,418	18,026	34,697	0.8%	-0.7%	1.6%	0.6%	-1.2%	2.0%

Table D-12: Energy Sales Forecast Comparison (GWh)

	Actual Energy Sales	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer
2013	27,443								25,981
2014	26,162							26,256	26,173
2015	24,584						24,909	26,941	26,441
2016	24,678					24,386	26,806	28,303	26,872
2017	24,223				24,327	24,310	27,901	29,821	26,895
2018	25,433			24,749	24,346	24,489	28,876	30,447	27,147
2019	24,677		25,041	23,984	23,737	23,879	28,273	29,703	25,949
2020	23,082	23,009	25,210	23,769	23,558	23,807	28,372	29,747	25,611

Table D-13: Forecast Sales less Actual Sales (GWh)

	Actual less Forecast (GWh)								Percent Difference							
	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer
2013								1,462								5.6%
2014							(94)	(11)							-0.4%	0.0%
2015						(325)	(2,357)	(1,857)						-1.3%	-8.7%	-7.0%
2016					292	(2,129)	(3,626)	(2,194)					1.2%	-7.9%	-12.8%	-8.2%
2017				(104)	(87)	(3,678)	(5,598)	(2,673)				-0.4%	-0.4%	-13.2%	-18.8%	-9.9%
2018			683	1,087	944	(3,443)	(5,015)	(1,714)			2.8%	4.5%	3.9%	-11.9%	-16.5%	-6.3%
2019		(364)	693	940	798	(3,596)	(5,026)	(1,272)		-1.5%	2.9%	4.0%	3.3%	-12.7%	-16.9%	-4.9%
2020	72	(2,128)	(688)	(477)	(725)	(5,290)	(6,665)	(2,529)	0.3%	-8.4%	-2.9%	-2.0%	-3.0%	-18.6%	-22.4%	-9.9%

Table D-14: Firm Load Obligation Coincident Peak Demand Forecast Comparison (MW)

	Actual Peak Demand	Interrupted Load at Peak	Available Interrupt Load 2020 Forecast	Available Interrupt Load 2019 Forecast	Available Interrupt Load 2018 Forecast	Available Interrupt Load 2017 Forecast	Available Interrupt Load 2016 Forecast	Available Interrupt Load 2015 Forecast	Available Interrupt Load 2014 Forecast	Available Interrupt Load 2013 Forecast	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer
2013	5,056	0								30								5,103
2014	4,871	0							31	34							4,940	5,102
2015	4,678	0						35	34	39						4,818	4,948	4,998
2016	4,836	0					41	36	36	44					4,748	4,993	5,199	5,077
2017	4,374	0				30	41	37	38	48				4,412	4,442	4,963	5,295	4,980
2018	4,648	0			32	30	42	38	40	53			4,423	4,452	4,496	5,158	5,443	5,053
2019	3,921	0		34	32	31	43	39	42	56		4,138	3,978	3,999	4,073	4,626	4,853	4,406
2020	3,774	0	28	26	32	31	43	40	43	59	4,008	4,161	4,023	4,045	4,146	4,757	4,982	4,485

Table D-15: Firm Load Obligation Actual Peak Demand less Firm Load Obligation Forecast Peak Demand (MW)

	Actual less Forecast (MW)								**Percent Difference**							
	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer
2013								(77)								-1.5%
2014							(99)	(265)							-2.0%	-5.2%
2015						(175)	(304)	(359)						-3.6%	-6.1%	-7.2%
2016					47	(194)	(400)	(285)					1.0%	-3.9%	-7.7%	-5.6%
2017				(68)	(110)	(626)	(960)	(654)				-1.6%	-2.5%	-12.6%	-18.1%	-13.1%
2018			193	165	110	(548)	(835)	(458)			4.4%	3.7%	2.4%	-10.6%	-15.3%	-9.1%
2019		(251)	(90)	(109)	(194)	(744)	(974)	(541)		-6.1%	-2.3%	-2.7%	-4.8%	-16.1%	-20.1%	-12.3%
2020	(263)	(413)	(282)	(302)	(416)	(1,023)	(1,251)	(770)	-6.6%	-9.9%	-7.0%	-7.5%	-10.0%	-21.5%	-25.1%	-17.2%

Table D-16: Weather Normalized Firm Load Obligation Coincident Peak Demand Forecast Comparison (MW)

	Actual Peak Demand	Interrupted Load at Peak	Available Interrupt Load 2020 Forecast	Available Interrupt Load 2019 Forecast	Available Interrupt Load 2018 Forecast	Available Interrupt Load 2017 Forecast	Available Interrupt Load 2016 Forecast	Available Interrupt Load 2015 Forecast	Available Interrupt Load 2014 Forecast	Available Interrupt Load 2013 Forecast	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer
2013	4,971	0				0	0	0	0	30								5,103
2014	4,889	0				0	0	0	31	34							4,940	5,102
2015	4,830	0				0	0	35	34	39						4,818	4,948	4,998
2016	4,753	0				0	41	36	36	44					4,748	4,993	5,199	5,077
2017	4,314	0				30	41	37	38	48				4,412	4,442	4,963	5,295	4,980
2018	4,511	0			32	30	42	38	40	53			4,423	4,452	4,496	5,158	5,443	5,053
2019	4,150	0		34	32	31	43	39	42	56		4,138	3,978	3,999	4,073	4,626	4,853	4,406
2020	3,868	0	28	26	32	31	43	40	43	59	4,008	4,161	4,023	4,045	4,146	4,757	4,982	4,485

Table D-17: Weather Normal Firm Load Obligation Peak Demand Less Firm Load Obligation Forecast Peak

	Actual less Forecast (MW)								Percent Difference							
	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer	2020 Forecast Summer	2019 Forecast Summer	2018 Forecast Summer	2017 Forecast Summer	2016 Forecast Summer	2015 Forecast Summer	2014 Forecast Summer	2013 Forecast Summer
2013								(163)								-3.2%
2014							(81)	(247)							-1.6%	-4.8%
2015						(23)	(152)	(207)						-0.5%	-3.1%	-4.1%
2016					(36)	(277)	(483)	(368)					-0.8%	-5.5%	-9.3%	-7.3%
2017				(128)	(170)	(686)	(1,020)	(714)				-2.9%	-3.8%	-13.8%	-19.3%	-14.3%
2018			56	28	(27)	(685)	(972)	(595)			1.3%	0.6%	-0.6%	-13.3%	-17.9%	-11.8%
2019		(22)	139	120	34	(515)	(745)	(312)		-0.5%	3.5%	3.0%	0.8%	-11.1%	-15.3%	-7.1%
2020	(168)	(319)	(187)	(207)	(321)	(929)	(1,157)	(675)	-4.2%	-7.7%	-4.7%	-5.1%	-7.7%	-19.5%	-23.2%	-15.1%

Southwestern Public Service Company
Hourly Load Profiles

This section contains 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.

The following monthly class load shapes are developed from company load research data for the year 2020. The following statistics were used for each requirement:

REQUIREMENT	STATISTIC
Peak Day	System Peak Day
Average Day	Average Weekday Excluding Holidays
Representative Off-Peak Day	Average Weekends and Holidays

The following pages contain tables and graphs for each of the load patterns described above.

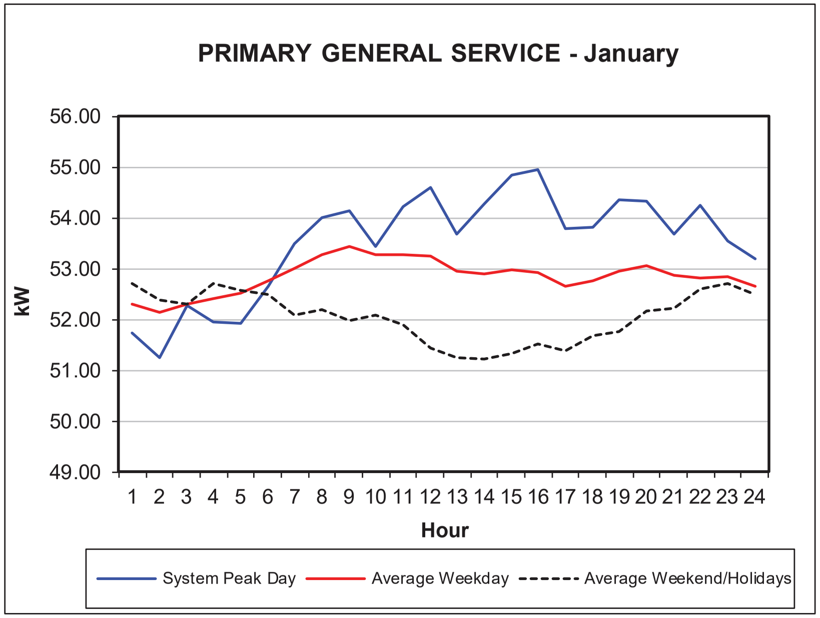
Primary General Service	Tables E-1.1 – E-1.12
Large Municipal and School	Tables E-2.1 – E-2.12
Small Municipal and School	Tables E-3.1 – E-3.12
Secondary General Service	Tables E-4.1 – E-4.12
Large General 69 kV	Tables E-5.1 – E-5.12
Large General Transmission Customers	Tables E-6.1 – E-6.12
Residential Regular	Tables E-7.1 – E-7.12
Residential Heat	Tables E-8.1 – E-8.12
Small General Service	Tables E-9.1 – E-9.12
Irrigation Power Service	Tables E-10.1 – E-10.12

Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	51.7257	52.3106	52.7106
2	51.2606	52.1350	52.3720
3	52.2814	52.3069	52.2953
4	51.9641	52.4187	52.7200
5	51.9168	52.5201	52.5755
6	52.6431	52.7617	52.4857
7	53.5030	53.0102	52.0912
8	53.9943	53.2836	52.1847
9	54.1367	53.4473	51.9871
10	53.4316	53.2681	52.0810
11	54.2230	53.2640	51.9067
12	54.5837	53.2491	51.4298
13	53.6688	52.9408	51.2506
14	54.2732	52.9053	51.2292
15	54.8444	52.9784	51.3255
16	54.9400	52.9220	51.5313
17	53.7904	52.6605	51.3832
18	53.8217	52.7498	51.6911
19	54.3586	52.9570	51.7649
20	54.3241	53.0660	52.1567
21	53.6750	52.8756	52.2329
22	54.2495	52.8281	52.6061
23	53.5526	52.8341	52.6993
24	53.1935	52.6547	52.4826

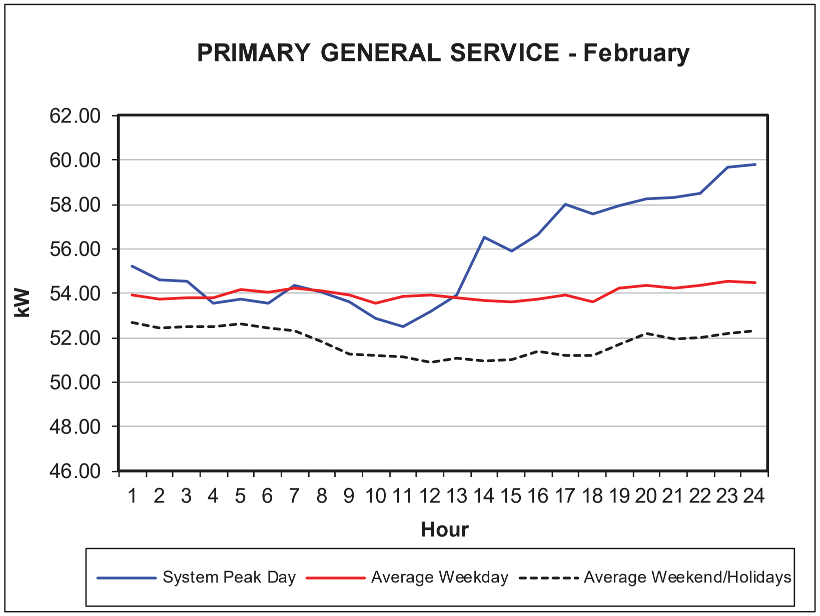


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	55.2179	53.9446	52.6591
2	54.6186	53.7354	52.4536
3	54.5307	53.7703	52.4896
4	53.5444	53.8184	52.5038
5	53.7296	54.1785	52.6379
6	53.5783	54.0221	52.4267
7	54.3839	54.2393	52.3227
8	54.0467	54.0771	51.8173
9	53.6191	53.9395	51.2338
10	52.8927	53.5244	51.1757
11	52.4834	53.8794	51.1093
12	53.2047	53.9156	50.9076
13	53.9344	53.8254	51.0748
14	56.5144	53.6770	50.9568
15	55.9007	53.6356	51.0360
16	56.6239	53.7118	51.3587
17	58.0271	53.9357	51.2182
18	57.5677	53.6107	51.2078
19	57.9461	54.2617	51.6999
20	58.2644	54.3496	52.1665
21	58.3195	54.2240	51.9652
22	58.5200	54.3382	52.0238
23	59.6428	54.5233	52.1681
24	59.8169	54.5063	52.3372

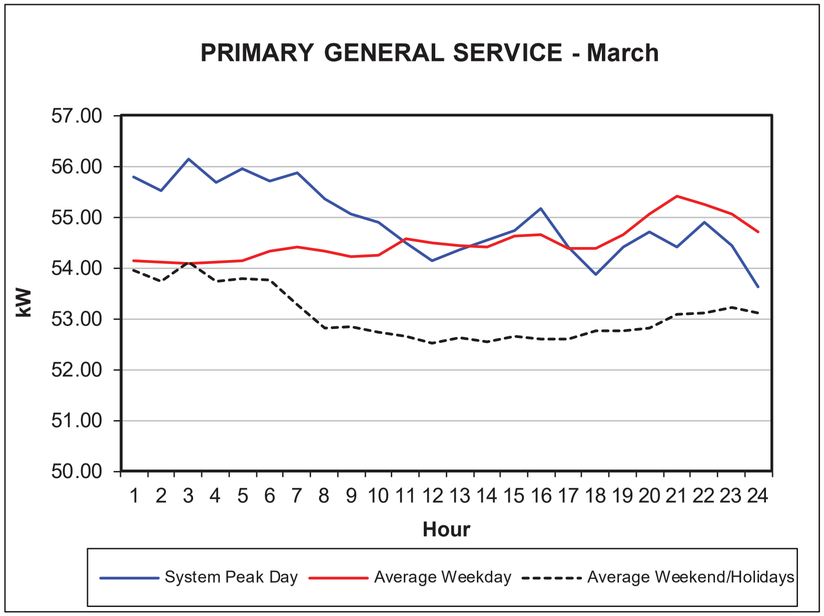


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	55.8011	54.1503	53.9446
2	55.5180	54.1014	53.7318
3	56.1315	54.0840	54.1018
4	55.6737	54.1224	53.7317
5	55.9523	54.1368	53.7794
6	55.6992	54.3296	53.7549
7	55.8744	54.4230	53.2865
8	55.3549	54.3188	52.8246
9	55.0488	54.2078	52.8291
10	54.9084	54.2514	52.7281
11	54.5006	54.5701	52.6577
12	54.1330	54.4784	52.5241
13	54.3653	54.4280	52.6275
14	54.5346	54.4071	52.5482
15	54.7457	54.6378	52.6578
16	55.1573	54.6625	52.5948
17	54.3970	54.3917	52.6006
18	53.8767	54.3830	52.7482
19	54.4095	54.6431	52.7716
20	54.7165	55.0701	52.8066
21	54.4148	55.4179	53.0808
22	54.9039	55.2590	53.1211
23	54.4267	55.0553	53.2062
24	53.6255	54.6951	53.1031

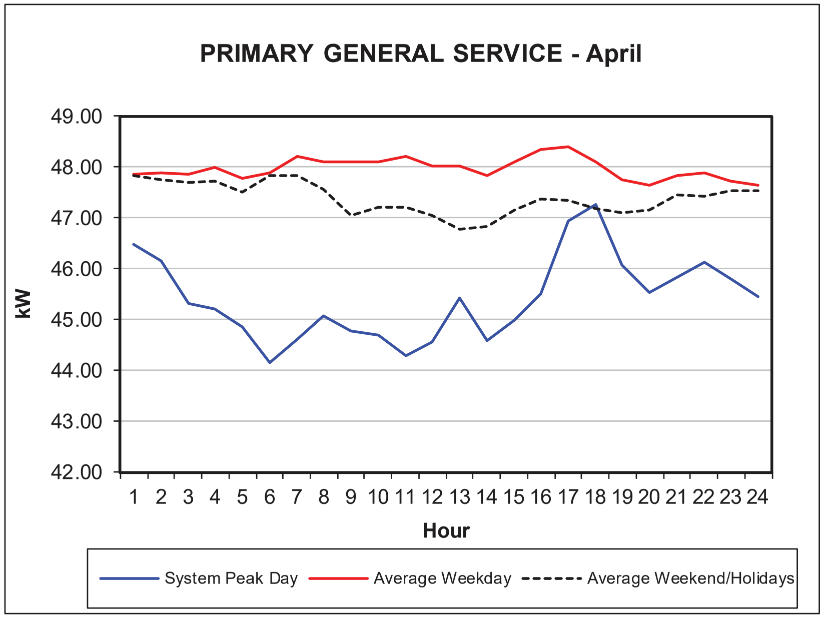


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	46.4903	47.8498	47.8437
2	46.1441	47.8853	47.7487
3	45.3061	47.8463	47.6924
4	45.2209	47.9976	47.7298
5	44.8487	47.7668	47.4985
6	44.1569	47.8778	47.8317
7	44.6043	48.2214	47.8218
8	45.0650	48.1114	47.5650
9	44.7883	48.1098	47.0423
10	44.6812	48.1154	47.2072
11	44.2844	48.2074	47.2024
12	44.5677	48.0134	47.0611
13	45.4373	48.0176	46.7765
14	44.5761	47.8335	46.8416
15	44.9989	48.1149	47.1493
16	45.5154	48.3421	47.3729
17	46.9293	48.4002	47.3579
18	47.2708	48.0994	47.1963
19	46.0693	47.7390	47.1048
20	45.5289	47.6373	47.1479
21	45.8274	47.8309	47.4644
22	46.1182	47.8889	47.4371
23	45.8011	47.7350	47.5292
24	45.4573	47.6494	47.5449

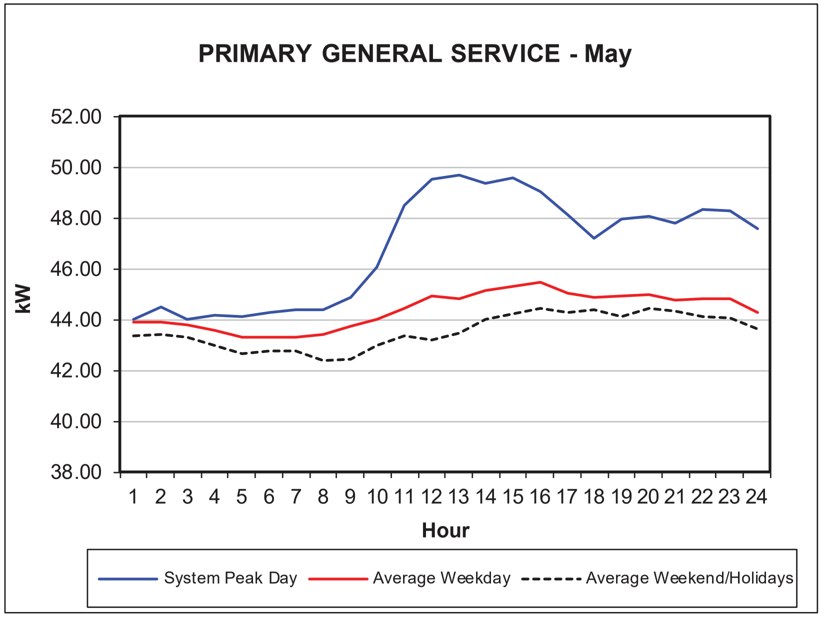


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	43.9854	43.8965	43.3718
2	44.5020	43.9223	43.4092
3	44.0038	43.7630	43.3208
4	44.1731	43.5548	43.0002
5	44.1254	43.3107	42.6297
6	44.2528	43.3194	42.7536
7	44.3849	43.2823	42.7402
8	44.3705	43.4021	42.3715
9	44.8613	43.7516	42.4599
10	46.0469	44.0198	42.9629
11	48.4965	44.4323	43.3656
12	49.5281	44.9023	43.1907
13	49.6796	44.8166	43.4589
14	49.3792	45.1453	44.0281
15	49.5708	45.3220	44.2152
16	49.0470	45.4914	44.4455
17	48.1247	45.0116	44.2844
18	47.2063	44.8520	44.3684
19	47.9714	44.9160	44.1285
20	48.0550	44.9585	44.4269
21	47.7922	44.7592	44.3134
22	48.3513	44.8210	44.1208
23	48.2575	44.8038	44.0782
24	47.5812	44.2754	43.6193

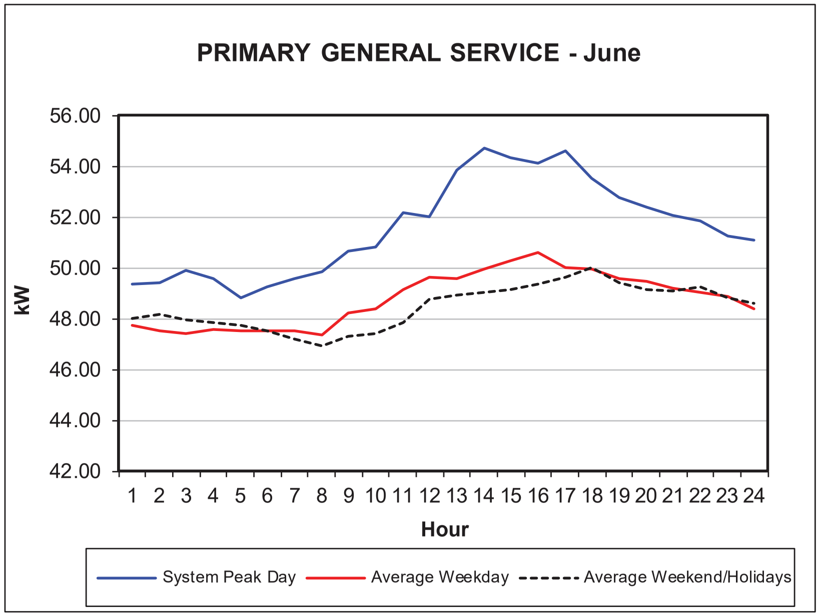


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	49.3698	47.7210	48.0245
2	49.4063	47.5206	48.1701
3	49.8783	47.4052	47.9631
4	49.5905	47.5554	47.8291
5	48.8294	47.5118	47.7588
6	49.2233	47.5227	47.4960
7	49.5513	47.5079	47.1699
8	49.8552	47.3531	46.9418
9	50.6563	48.1981	47.3037
10	50.8027	48.3923	47.4100
11	52.1690	49.1304	47.8304
12	52.0243	49.6435	48.7444
13	53.8443	49.5734	48.9183
14	54.6921	49.9302	49.0292
15	54.3173	50.2915	49.1334
16	54.1062	50.6280	49.3650
17	54.5923	49.9868	49.6476
18	53.5060	49.9365	50.0126
19	52.7482	49.5533	49.3996
20	52.3771	49.4663	49.1562
21	52.0785	49.1861	49.1029
22	51.8407	49.0405	49.2446
23	51.2647	48.8966	48.8122
24	51.1032	48.4002	48.5828

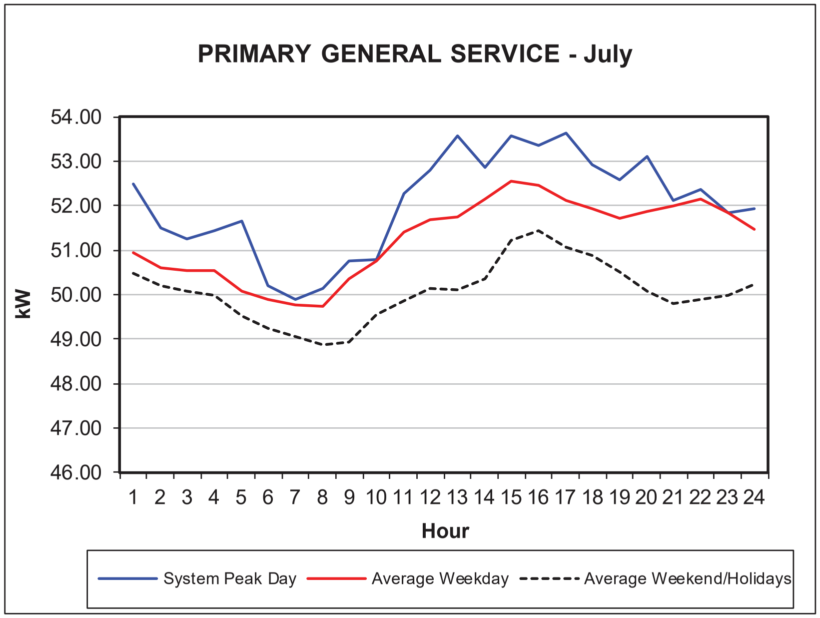


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	52.4880	50.9545	50.4836
2	51.5018	50.5991	50.2034
3	51.2410	50.5292	50.0657
4	51.4338	50.5460	49.9732
5	51.6658	50.0664	49.5290
6	50.1966	49.8799	49.2341
7	49.9005	49.7665	49.0586
8	50.1388	49.7403	48.8575
9	50.7429	50.3669	48.9418
10	50.7923	50.7471	49.5348
11	52.2545	51.3926	49.8603
12	52.7839	51.6837	50.1242
13	53.5570	51.7366	50.1057
14	52.8554	52.1423	50.3447
15	53.5541	52.5534	51.2096
16	53.3518	52.4567	51.4428
17	53.6306	52.1167	51.0619
18	52.9094	51.9380	50.8665
19	52.5663	51.7211	50.5061
20	53.0920	51.8788	50.0755
21	52.1180	51.9919	49.7821
22	52.3634	52.1366	49.8894
23	51.8416	51.8365	49.9677
24	51.9379	51.4651	50.2417

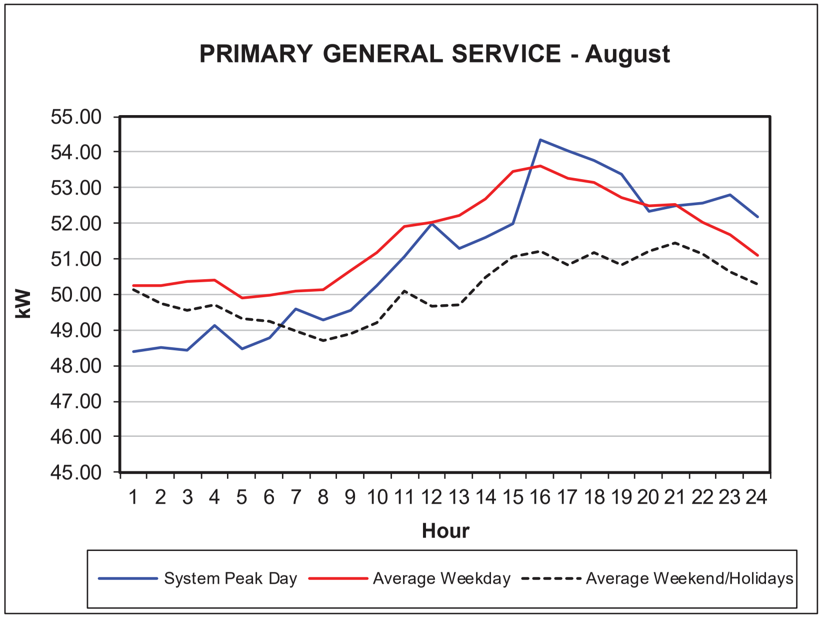


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	48.4087	50.2323	50.1308
2	48.5211	50.2480	49.7294
3	48.4471	50.3550	49.5521
4	49.1207	50.4108	49.6944
5	48.4744	49.9173	49.3344
6	48.7643	49.9722	49.2288
7	49.5828	50.1071	48.9686
8	49.2652	50.1498	48.7034
9	49.5491	50.6538	48.9072
10	50.2660	51.1570	49.2113
11	51.0526	51.9271	50.0882
12	51.9787	52.0143	49.6519
13	51.2770	52.2065	49.7157
14	51.6186	52.6785	50.4662
15	51.9949	53.4565	51.0635
16	54.3334	53.6130	51.2004
17	54.0374	53.2677	50.8291
18	53.7825	53.1519	51.1906
19	53.3936	52.7330	50.8312
20	52.3362	52.5041	51.1964
21	52.5075	52.5216	51.4409
22	52.5660	52.0395	51.1416
23	52.7818	51.6641	50.6461
24	52.1906	51.0920	50.2779

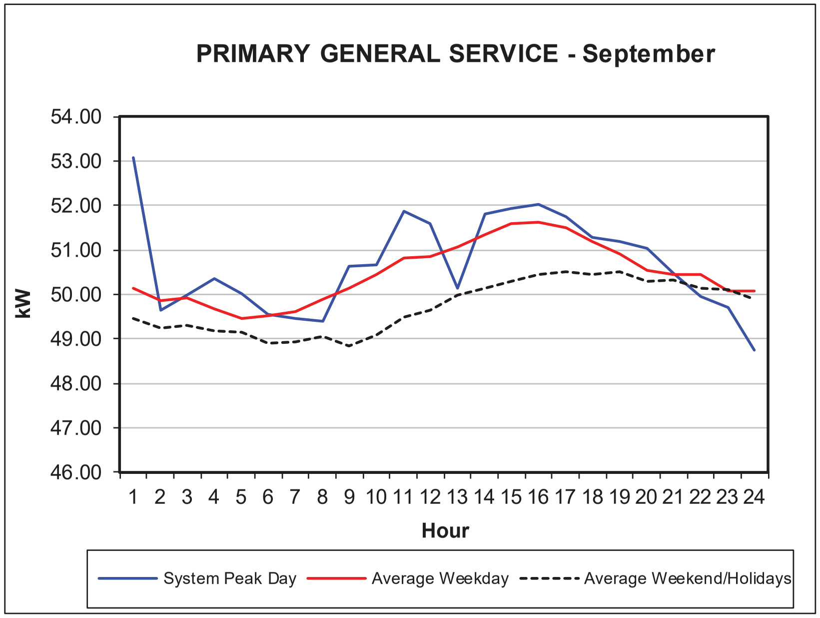


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	53.0611	50.1463	49.4708
2	49.6479	49.8465	49.2450
3	49.9849	49.9310	49.2926
4	50.3636	49.6648	49.1704
5	50.0155	49.4580	49.1386
6	49.5637	49.5047	48.8956
7	49.4618	49.5988	48.9205
8	49.4069	49.8841	49.0467
9	50.6347	50.1298	48.8421
10	50.6630	50.4321	49.0811
11	51.8611	50.8274	49.5015
12	51.5874	50.8576	49.6418
13	50.1265	51.0510	49.9863
14	51.8148	51.3532	50.1379
15	51.9266	51.5959	50.2943
16	52.0205	51.6358	50.4371
17	51.7447	51.4826	50.5096
18	51.2877	51.1978	50.4594
19	51.1818	50.8945	50.5133
20	51.0294	50.5329	50.2964
21	50.4867	50.4514	50.3309
22	49.9516	50.4304	50.1407
23	49.7108	50.0880	50.1199
24	48.7527	50.0742	49.8965

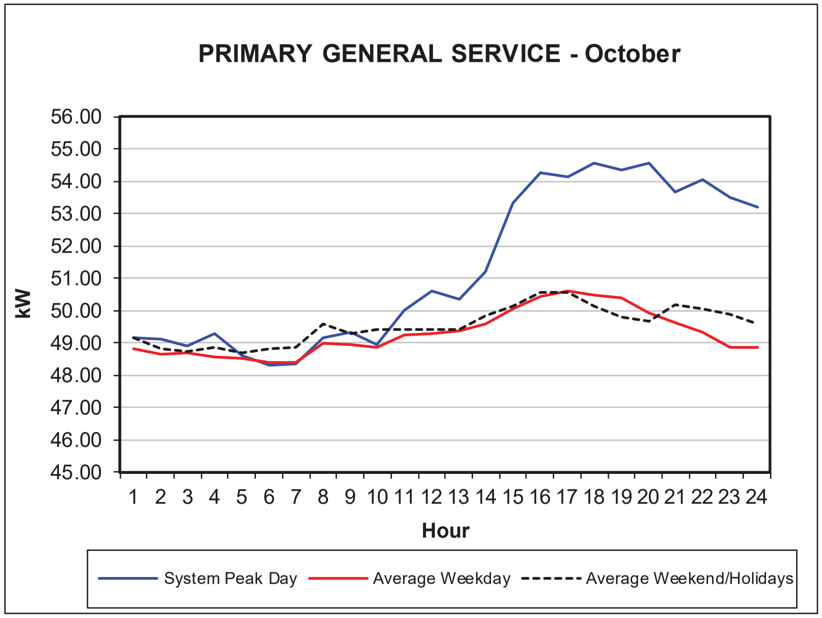


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	49.1643	48.8309	49.1528
2	49.1027	48.6359	48.8358
3	48.9072	48.7094	48.7134
4	49.2799	48.5417	48.8777
5	48.6245	48.5375	48.7070
6	48.3132	48.3833	48.8360
7	48.3601	48.3814	48.8549
8	49.1359	48.9724	49.5691
9	49.3093	48.9316	49.2993
10	48.9246	48.8738	49.4126
11	49.9975	49.2491	49.4145
12	50.6230	49.2996	49.3991
13	50.3578	49.3619	49.4254
14	51.1876	49.5654	49.8300
15	53.3271	50.0643	50.1358
16	54.2597	50.4379	50.5410
17	54.1182	50.6077	50.5684
18	54.5473	50.4793	50.1382
19	54.3529	50.3785	49.7885
20	54.5602	49.9186	49.6659
21	53.6433	49.6277	50.1941
22	54.0433	49.3133	50.0355
23	53.5030	48.8744	49.8713
24	53.1957	48.8454	49.6029

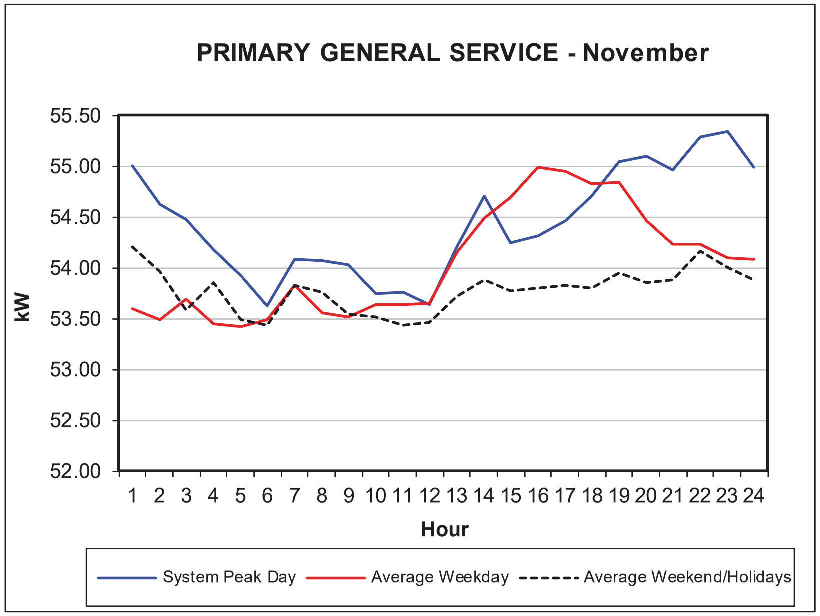


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	55.0085	53.5977	54.1993
2	54.6287	53.4916	53.9555
3	54.4755	53.6869	53.5866
4	54.1723	53.4517	53.8511
5	53.9223	53.4192	53.4947
6	53.6228	53.4841	53.4318
7	54.0880	53.8265	53.8259
8	54.0632	53.5595	53.7559
9	54.0320	53.5202	53.5453
10	53.7455	53.6307	53.5139
11	53.7617	53.6425	53.4359
12	53.6410	53.6437	53.4658
13	54.2093	54.1493	53.7146
14	54.6993	54.4846	53.8860
15	54.2397	54.6894	53.7733
16	54.3153	54.9841	53.7989
17	54.4677	54.9424	53.8296
18	54.7105	54.8267	53.8039
19	55.0452	54.8393	53.9439
20	55.0946	54.4672	53.8471
21	54.9567	54.2276	53.8761
22	55.2857	54.2294	54.1665
23	55.3405	54.0988	53.9987
24	54.9917	54.0894	53.8789

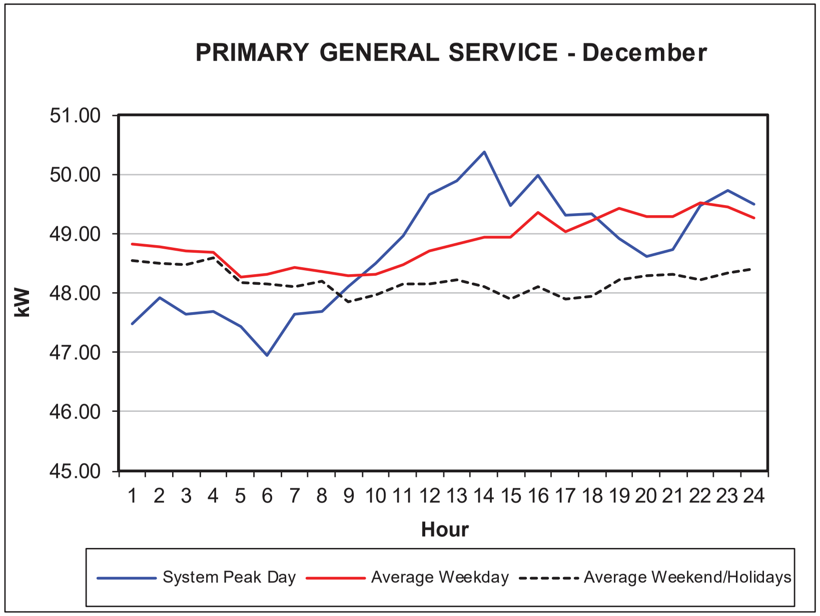


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-1.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	47.4839	48.8218	48.5369
2	47.9219	48.7840	48.4994
3	47.6504	48.7065	48.4737
4	47.7003	48.6905	48.5955
5	47.4298	48.2700	48.1741
6	46.9468	48.3080	48.1484
7	47.6411	48.4404	48.1078
8	47.6792	48.3639	48.1941
9	48.1075	48.2846	47.8626
10	48.5035	48.3160	47.9597
11	48.9712	48.4774	48.1423
12	49.6525	48.7055	48.1613
13	49.8835	48.8199	48.2203
14	50.3731	48.9481	48.1177
15	49.4833	48.9392	47.8870
16	49.9962	49.3653	48.1132
17	49.3109	49.0454	47.8982
18	49.3291	49.2201	47.9547
19	48.9111	49.4389	48.2191
20	48.6279	49.2932	48.2950
21	48.7363	49.3003	48.3123
22	49.4861	49.5165	48.2246
23	49.7353	49.4618	48.3298
24	49.5003	49.2653	48.4186

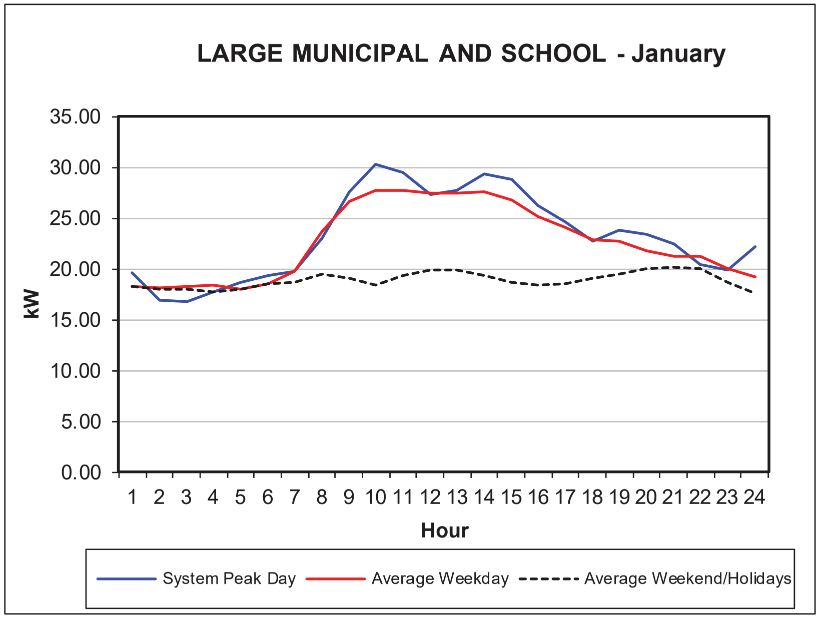


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.6477	18.2490	18.2753
2	16.9769	18.0652	18.0198
3	16.7492	18.3334	17.9626
4	17.7754	18.3887	17.6670
5	18.6856	18.0588	17.9497
6	19.3915	18.4740	18.4729
7	19.7311	19.7858	18.6672
8	23.0107	23.6844	19.4392
9	27.6072	26.5928	19.0154
10	30.3452	27.7786	18.3463
11	29.4099	27.7104	19.2824
12	27.3583	27.4817	19.8432
13	27.7269	27.4932	19.8597
14	29.2969	27.5810	19.3082
15	28.7849	26.7535	18.7113
16	26.1836	25.1456	18.4610
17	24.6153	24.1358	18.5910
18	22.6654	22.8732	19.1190
19	23.7530	22.6970	19.4243
20	23.3505	21.7256	20.0253
21	22.5064	21.2949	20.1972
22	20.4362	21.2599	20.0330
23	19.9445	20.0809	18.6100
24	22.1473	19.2261	17.5257

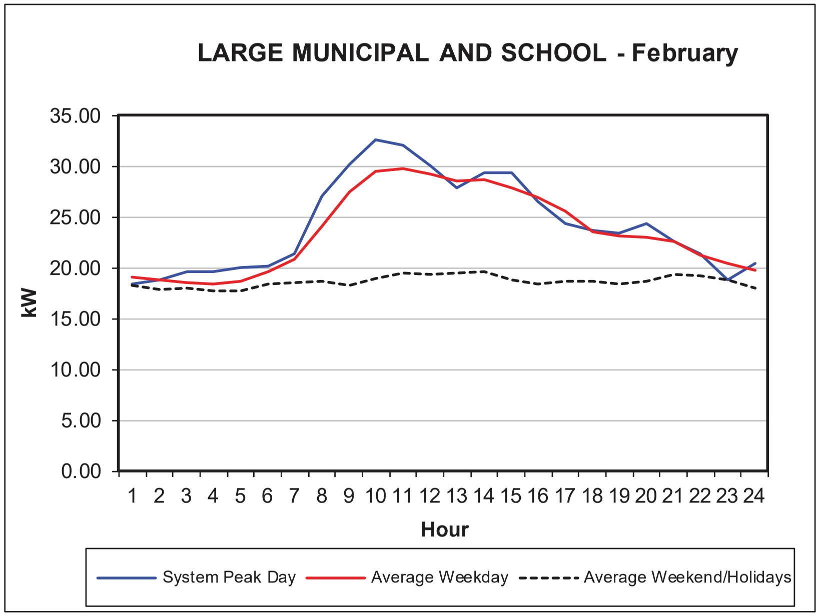


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18.4501	19.1115	18.2174
2	18.8069	18.7852	17.9052
3	19.6881	18.6048	18.0153
4	19.6679	18.3637	17.7472
5	20.0224	18.6727	17.7802
6	20.1323	19.6097	18.3668
7	21.3950	20.8557	18.5796
8	27.1206	24.0540	18.6599
9	30.1794	27.4257	18.2854
10	32.6399	29.4629	18.9342
11	32.0706	29.7692	19.4357
12	30.0590	29.2132	19.3956
13	27.8556	28.6024	19.4513
14	29.3499	28.6455	19.5890
15	29.3866	27.9311	18.8453
16	26.5766	26.9348	18.4633
17	24.4204	25.5469	18.6902
18	23.6276	23.5824	18.6987
19	23.4356	23.1065	18.3502
20	24.3041	23.0481	18.7327
21	22.6401	22.6389	19.3021
22	21.3419	21.2131	19.1878
23	18.8022	20.4205	18.8019
24	20.4553	19.7095	18.0692

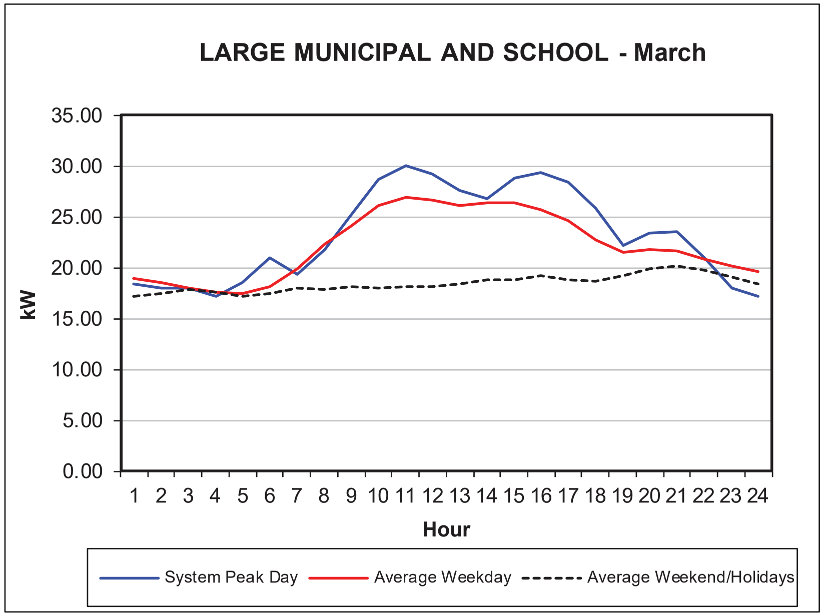


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18.3856	18.9507	17.1879
2	17.9567	18.5877	17.4654
3	18.0570	18.0396	17.9069
4	17.2152	17.5636	17.5284
5	18.5177	17.5115	17.1764
6	21.0308	18.1374	17.5070
7	19.3459	19.8172	17.9494
8	21.7452	22.3221	17.8231
9	25.1019	24.0504	18.0850
10	28.7001	26.1288	17.9521
11	30.0172	26.9603	18.1169
12	29.2104	26.7086	18.1453
13	27.5822	26.1463	18.3872
14	26.8370	26.3170	18.7936
15	28.8634	26.3733	18.8503
16	29.2994	25.7074	19.1610
17	28.4560	24.6117	18.7698
18	25.9034	22.7866	18.6827
19	22.1437	21.5415	19.1969
20	23.3514	21.7203	19.9236
21	23.5659	21.7033	20.1714
22	20.9631	20.7825	19.7612
23	17.9600	20.1697	19.1378
24	17.2209	19.6810	18.4263

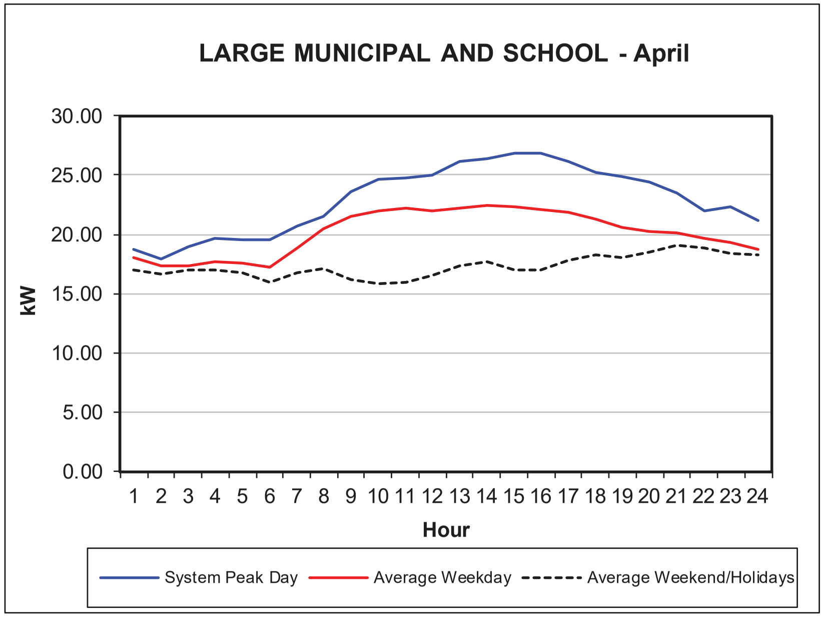


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18.7800	17.9977	17.0033
2	17.9474	17.3457	16.6053
3	18.9208	17.3729	17.0422
4	19.6475	17.6401	16.9412
5	19.5714	17.6335	16.7666
6	19.5669	17.2341	16.0100
7	20.7595	18.8195	16.7935
8	21.5713	20.4401	17.1614
9	23.6355	21.4859	16.2195
10	24.6080	21.9270	15.8395
11	24.7927	22.2380	15.9578
12	25.0190	22.0233	16.5820
13	26.1118	22.1827	17.3255
14	26.4023	22.4914	17.6992
15	26.8792	22.3686	17.0503
16	26.8390	22.1003	16.9717
17	26.0981	21.8879	17.7518
18	25.1951	21.2387	18.2267
19	24.9358	20.6357	18.0730
20	24.4618	20.2955	18.4488
21	23.4908	20.1784	19.0487
22	21.9346	19.6075	18.8428
23	22.3350	19.3227	18.4424
24	21.1450	18.7023	18.2351

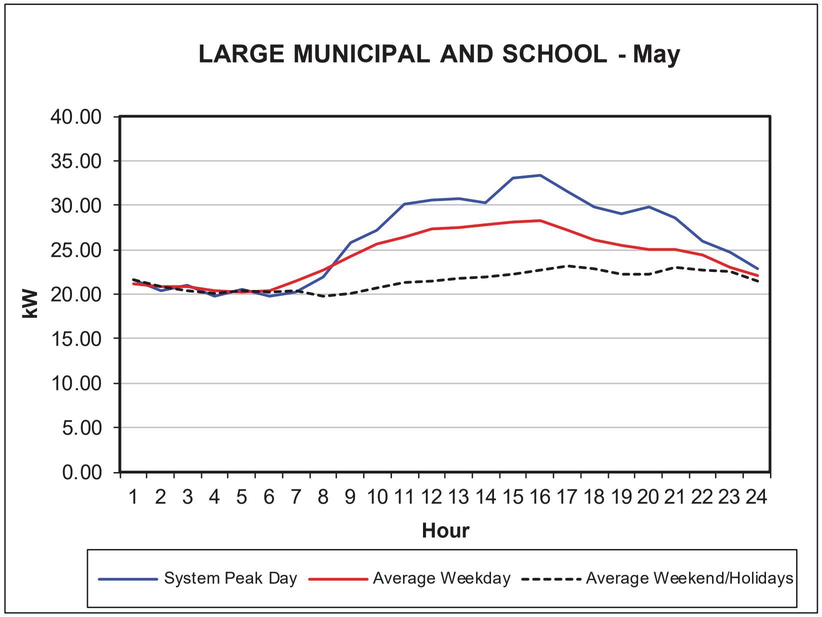


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	21.7076	21.2377	21.6648
2	20.4315	20.8567	20.8808
3	20.9659	20.8219	20.3785
4	19.7571	20.3960	20.0215
5	20.6376	20.2999	20.3300
6	19.8597	20.3572	20.2374
7	20.2200	21.4403	20.3501
8	22.0151	22.7267	19.8163
9	25.8374	24.2035	20.0310
10	27.2655	25.6019	20.7408
11	30.1357	26.4456	21.4020
12	30.5322	27.3525	21.5465
13	30.7145	27.4501	21.8286
14	30.2764	27.7744	21.9261
15	33.0178	28.0758	22.3150
16	33.3820	28.2794	22.7609
17	31.5428	27.2404	23.1302
18	29.9082	26.1292	22.8372
19	29.1390	25.5145	22.3299
20	29.8464	24.9761	22.1936
21	28.6404	25.1080	23.0376
22	25.9497	24.4061	22.6615
23	24.7106	23.0254	22.5310
24	22.8662	22.0777	21.4147

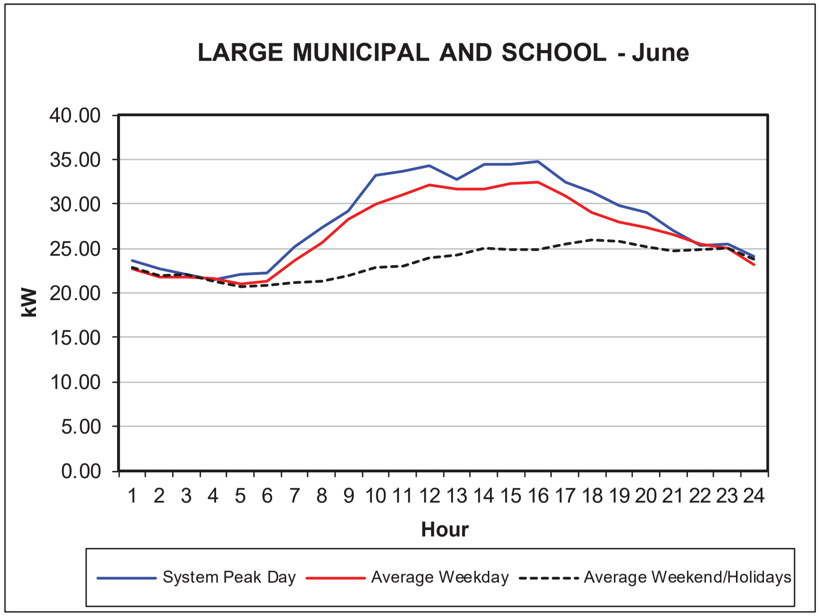


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	23.5799	22.7108	22.9042
2	22.7904	21.8326	22.0239
3	22.1006	21.8194	22.0564
4	21.4616	21.6991	21.3610
5	22.1559	21.1005	20.6593
6	22.2081	21.2815	20.8467
7	25.2008	23.7012	21.1199
8	27.3511	25.6538	21.3774
9	29.2449	28.2509	21.8836
10	33.2160	30.0282	22.8346
11	33.6432	31.0352	23.0875
12	34.3144	32.2177	23.9851
13	32.8285	31.7194	24.2502
14	34.4374	31.7388	25.0070
15	34.4493	32.2749	24.9569
16	34.8064	32.4668	24.8945
17	32.4224	30.8654	25.5049
18	31.4079	29.1237	26.0222
19	29.8001	28.0331	25.7761
20	28.9927	27.3313	25.1473
21	27.0626	26.6400	24.7266
22	25.3987	25.5644	24.9427
23	25.5450	25.0361	25.0467
24	24.0598	23.2295	23.7739

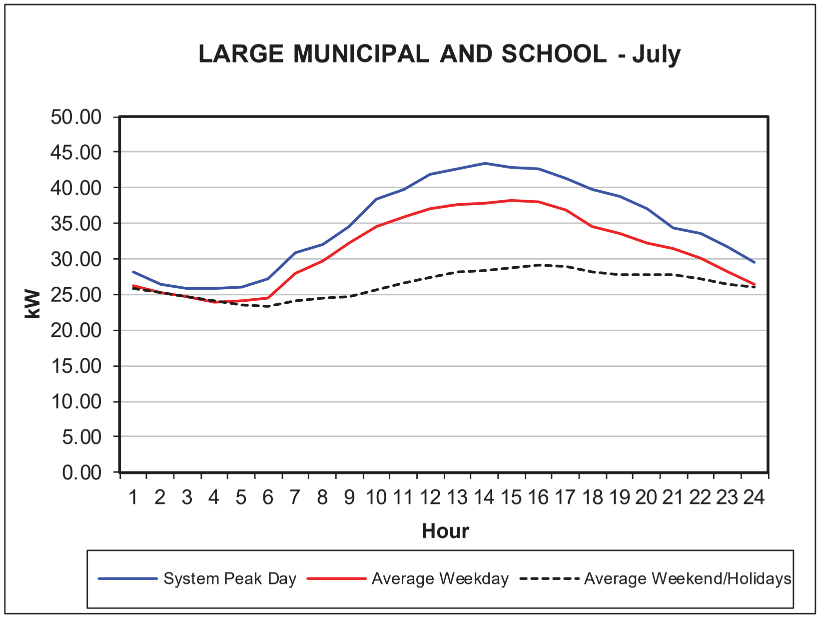


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	28.2088	26.1521	25.7802
2	26.4253	25.3055	25.3657
3	25.9281	24.6068	24.6789
4	25.9344	24.0135	24.0650
5	26.0189	24.0346	23.5278
6	27.1441	24.4816	23.3818
7	30.9525	27.9756	24.0869
8	32.1031	29.7966	24.4061
9	34.5664	32.2066	24.7449
10	38.3458	34.5191	25.7142
11	39.7151	35.8145	26.6753
12	41.8981	37.0045	27.4026
13	42.6929	37.6935	28.1120
14	43.3614	37.9144	28.2829
15	42.8197	38.2978	28.7370
16	42.7184	38.0351	29.1039
17	41.2788	36.9095	28.9229
18	39.7374	34.6119	28.1875
19	38.7049	33.5810	27.8269
20	37.0694	32.2989	27.8211
21	34.2674	31.4377	27.7653
22	33.5543	30.1638	27.1088
23	31.7386	28.2041	26.4260
24	29.5294	26.5241	26.0129

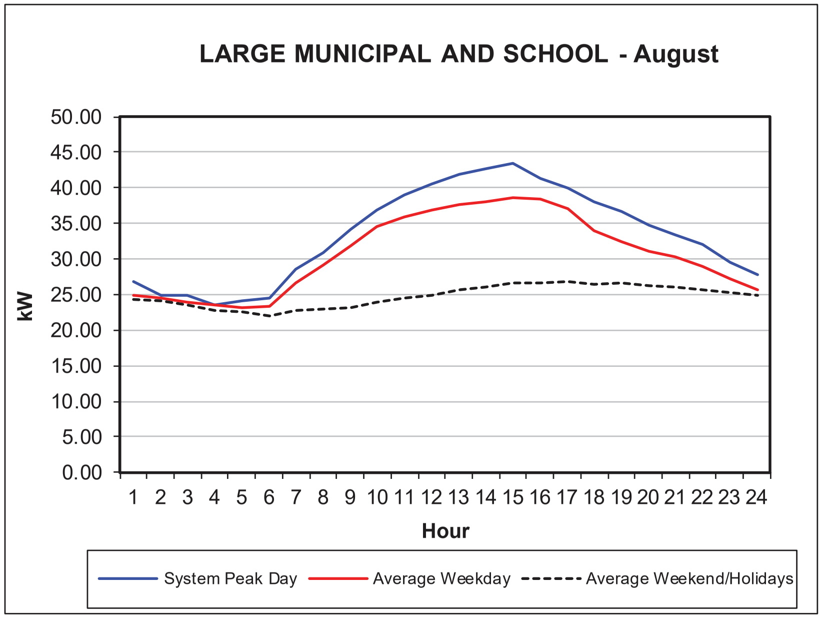


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	26.8491	24.9462	24.4018
2	24.8421	24.4047	24.0727
3	24.9576	24.0121	23.4627
4	23.6191	23.4691	22.8188
5	24.1151	23.1014	22.4866
6	24.5302	23.3964	21.9682
7	28.5282	26.5599	22.8404
8	30.9406	29.0948	22.9896
9	34.1616	31.8492	23.1812
10	36.8848	34.5831	23.8837
11	38.9262	35.8899	24.5298
12	40.5783	36.8696	24.9592
13	41.8351	37.6434	25.7388
14	42.7212	38.0438	26.1040
15	43.4762	38.6919	26.5622
16	41.3641	38.3581	26.6813
17	40.0512	36.9772	26.8067
18	38.0835	33.9952	26.4391
19	36.5774	32.4019	26.5612
20	34.8141	31.0045	26.2853
21	33.3735	30.2574	26.1275
22	31.9530	28.9505	25.5832
23	29.5818	27.2777	25.2939
24	27.7713	25.7379	24.9438

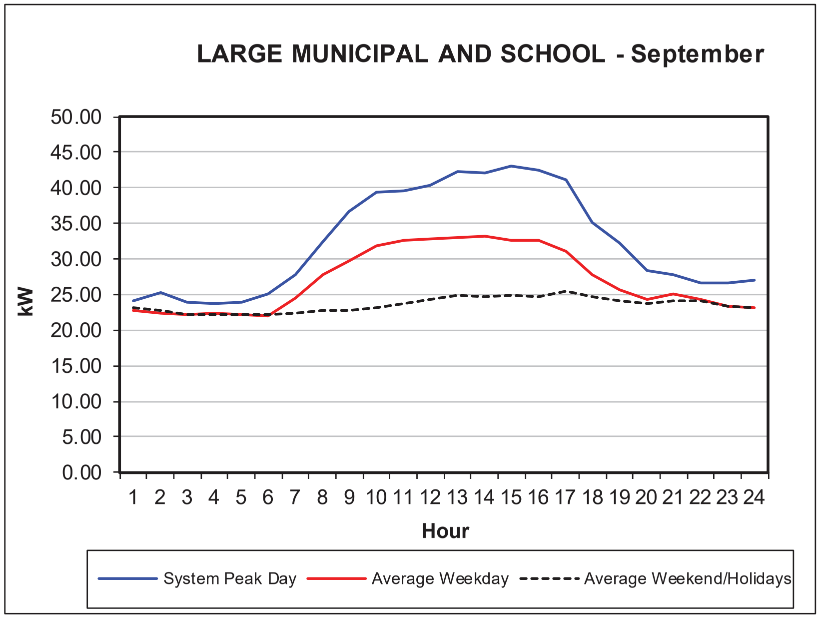


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	24.0678	22.7812	23.1691
2	25.2188	22.3931	22.7605
3	23.9562	22.1671	22.1413
4	23.6432	22.4403	22.1365
5	23.9559	22.2436	22.1166
6	25.0377	22.0813	22.1895
7	27.8697	24.5436	22.4248
8	32.5086	27.8466	22.7832
9	36.6989	29.6869	22.7073
10	39.3748	31.7586	23.1612
11	39.6580	32.5208	23.6673
12	40.3943	32.7992	24.3547
13	42.2058	33.0760	24.9320
14	42.0061	33.1392	24.7885
15	43.0479	32.6736	24.8242
16	42.5190	32.5252	24.7688
17	41.1075	31.1356	25.3746
18	35.0481	27.7621	24.7849
19	32.2980	25.6820	24.1380
20	28.3495	24.3654	23.7504
21	27.8074	25.0906	24.1910
22	26.5430	24.3583	24.1215
23	26.6556	23.3711	23.4358
24	27.0928	23.2039	23.1621

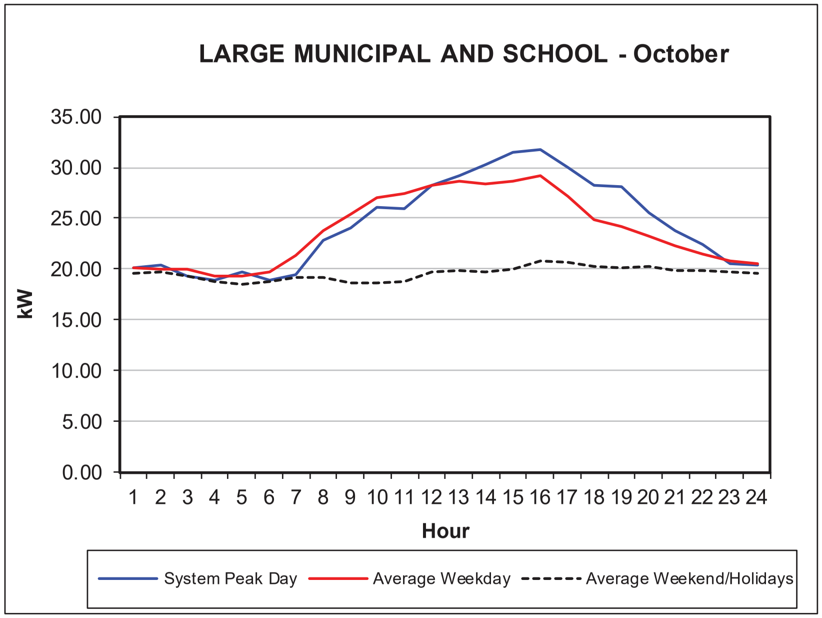


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	20.1081	20.0683	19.5633
2	20.4336	19.9968	19.6789
3	19.3241	19.9884	19.3133
4	18.8925	19.2722	18.7836
5	19.7749	19.2870	18.5605
6	18.8633	19.6713	18.8310
7	19.5066	21.3114	19.1291
8	22.8209	23.7273	19.1118
9	24.0000	25.4007	18.5882
10	26.0651	26.9842	18.5932
11	25.8946	27.4637	18.7246
12	28.2997	28.2069	19.6712
13	29.2182	28.6578	19.9043
14	30.2430	28.4086	19.6636
15	31.4272	28.7017	19.9533
16	31.7155	29.1212	20.7840
17	29.9817	27.1446	20.6071
18	28.2048	24.9103	20.2768
19	28.0420	24.1406	20.0729
20	25.5630	23.2603	20.3062
21	23.8417	22.3384	19.8985
22	22.4573	21.5213	19.8994
23	20.5068	20.8110	19.7089
24	20.3866	20.5042	19.5732

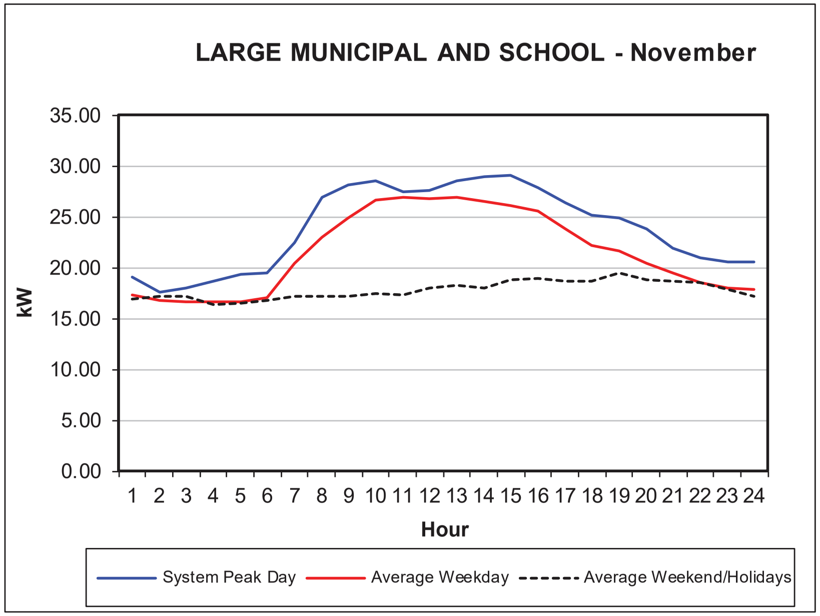


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.0788	17.2835	16.9184
2	17.6175	16.7735	17.2218
3	17.9778	16.6225	17.1813
4	18.6071	16.6979	16.3425
5	19.4026	16.6106	16.5163
6	19.4859	17.0571	16.7415
7	22.4197	20.4191	17.1924
8	26.8740	23.0031	17.1973
9	28.0967	24.8961	17.1581
10	28.5607	26.6859	17.4592
11	27.4876	26.9764	17.2829
12	27.6548	26.7931	17.9886
13	28.4786	26.8521	18.2982
14	28.9638	26.5020	17.9969
15	29.0538	26.0989	18.8496
16	27.9115	25.5241	18.9328
17	26.4124	23.8416	18.6245
18	25.1740	22.2408	18.7261
19	24.8233	21.6423	19.5002
20	23.8696	20.4726	18.7920
21	21.9157	19.4420	18.6825
22	20.9979	18.5628	18.5505
23	20.5957	18.0170	17.9132
24	20.5424	17.9013	17.1711

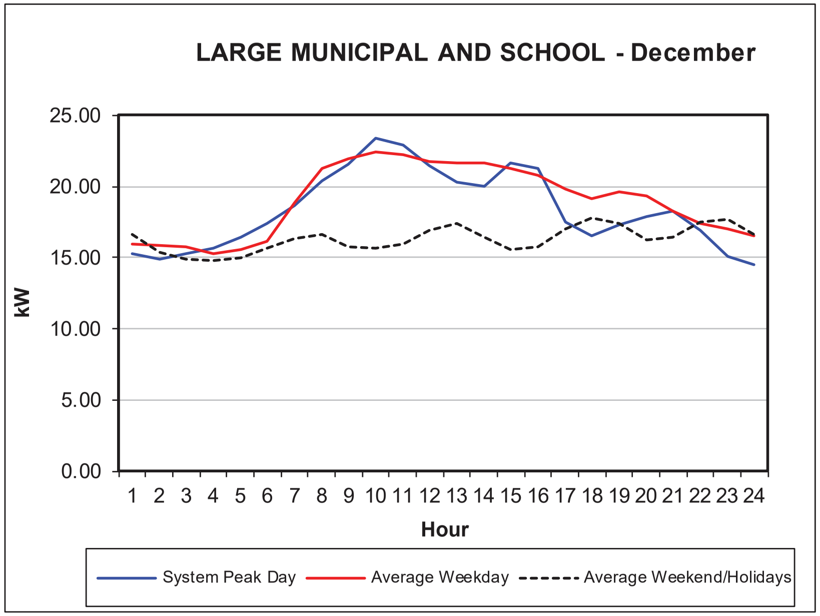


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-2.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.2375	15.9383	16.5863
2	14.8681	15.7994	15.3265
3	15.2776	15.7170	14.8509
4	15.6184	15.2613	14.7997
5	16.4607	15.5446	14.9884
6	17.3883	16.1585	15.6573
7	18.6379	18.8772	16.3346
8	20.3676	21.2546	16.5708
9	21.5176	21.9479	15.7827
10	23.3507	22.3722	15.6784
11	22.8872	22.1949	15.9592
12	21.4037	21.7688	16.8831
13	20.2650	21.6626	17.4101
14	20.0110	21.6290	16.4654
15	21.6250	21.2961	15.6001
16	21.2873	20.8017	15.7619
17	17.5067	19.8127	17.0125
18	16.5422	19.0894	17.7437
19	17.2913	19.6443	17.3752
20	17.8820	19.2969	16.2500
21	18.2830	18.3079	16.4215
22	16.9028	17.4203	17.4895
23	15.0391	16.9969	17.6717
24	14.4510	16.5038	16.6661

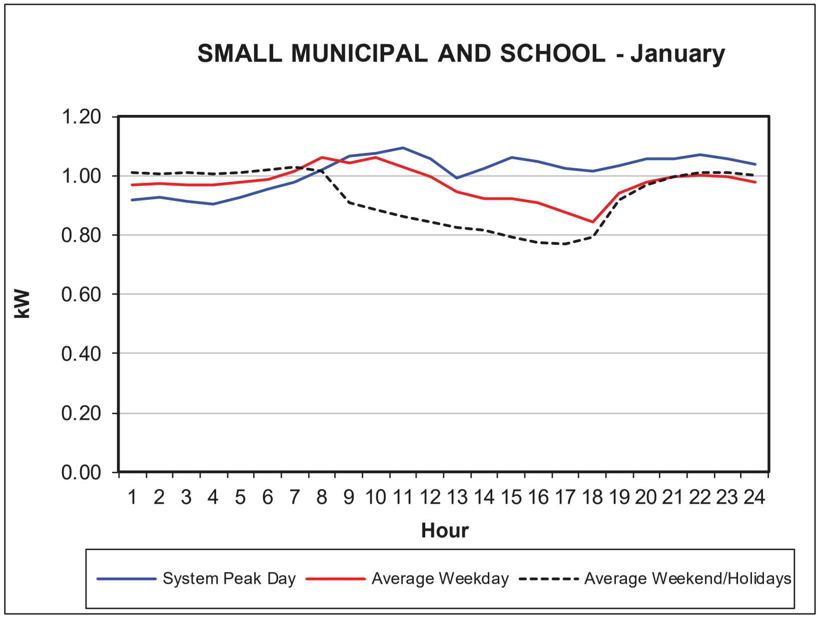


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9169	0.9701	1.0105
2	0.9274	0.9721	1.0077
3	0.9153	0.9698	1.0093
4	0.9056	0.9678	1.0077
5	0.9282	0.9760	1.0126
6	0.9561	0.9878	1.0189
7	0.9789	1.0127	1.0272
8	1.0207	1.0630	1.0138
9	1.0655	1.0449	0.9096
10	1.0743	1.0617	0.8852
11	1.0922	1.0300	0.8615
12	1.0572	0.9970	0.8445
13	0.9901	0.9475	0.8275
14	1.0230	0.9220	0.8152
15	1.0623	0.9222	0.7921
16	1.0454	0.9096	0.7750
17	1.0255	0.8761	0.7699
18	1.0160	0.8441	0.7931
19	1.0355	0.9404	0.9195
20	1.0554	0.9790	0.9707
21	1.0555	0.9968	0.9956
22	1.0686	0.9994	1.0120
23	1.0554	0.9961	1.0097
24	1.0366	0.9775	1.0025

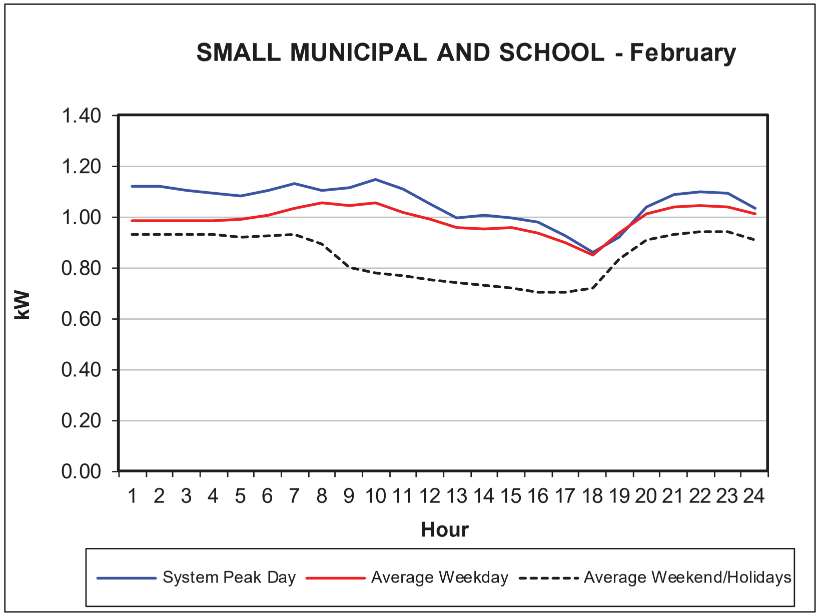


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1218	0.9861	0.9295
2	1.1229	0.9855	0.9324
3	1.1042	0.9834	0.9286
4	1.0942	0.9873	0.9303
5	1.0840	0.9929	0.9182
6	1.1040	1.0057	0.9271
7	1.1307	1.0352	0.9311
8	1.1031	1.0536	0.8930
9	1.1170	1.0431	0.8010
10	1.1485	1.0566	0.7818
11	1.1115	1.0159	0.7676
12	1.0479	0.9927	0.7531
13	0.9972	0.9582	0.7436
14	1.0070	0.9537	0.7317
15	0.9981	0.9581	0.7198
16	0.9818	0.9384	0.7037
17	0.9269	0.8980	0.7039
18	0.8584	0.8513	0.7190
19	0.9188	0.9374	0.8323
20	1.0384	1.0124	0.9089
21	1.0898	1.0374	0.9335
22	1.1009	1.0437	0.9407
23	1.0912	1.0393	0.9444
24	1.0347	1.0148	0.9078

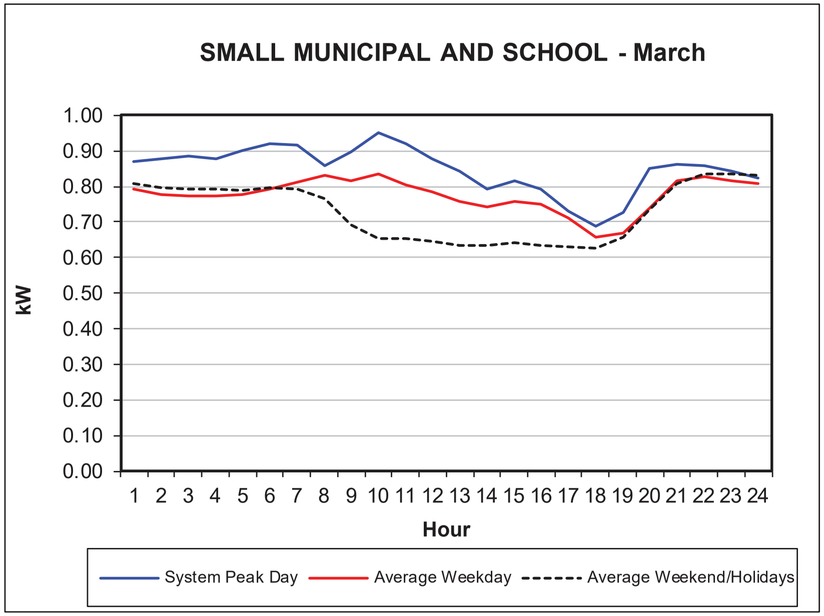


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8710	0.7911	0.8085
2	0.8761	0.7755	0.7955
3	0.8839	0.7745	0.7932
4	0.8788	0.7733	0.7941
5	0.8989	0.7762	0.7890
6	0.9183	0.7914	0.7970
7	0.9176	0.8100	0.7918
8	0.8583	0.8298	0.7635
9	0.8949	0.8167	0.6928
10	0.9491	0.8333	0.6545
11	0.9185	0.8023	0.6526
12	0.8786	0.7848	0.6455
13	0.8411	0.7565	0.6333
14	0.7935	0.7438	0.6355
15	0.8168	0.7570	0.6397
16	0.7938	0.7503	0.6341
17	0.7312	0.7120	0.6281
18	0.6871	0.6559	0.6257
19	0.7282	0.6700	0.6589
20	0.8496	0.7368	0.7345
21	0.8616	0.8150	0.8082
22	0.8566	0.8288	0.8359
23	0.8434	0.8164	0.8355
24	0.8232	0.8069	0.8299

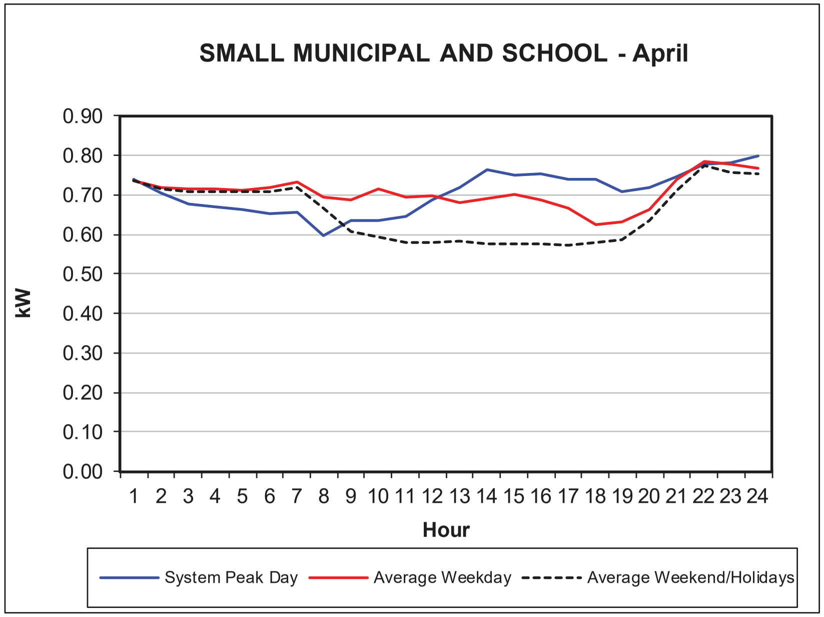


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7401	0.7356	0.7372
2	0.7043	0.7187	0.7165
3	0.6752	0.7162	0.7066
4	0.6704	0.7162	0.7084
5	0.6612	0.7118	0.7080
6	0.6526	0.7173	0.7094
7	0.6553	0.7317	0.7169
8	0.5965	0.6941	0.6658
9	0.6339	0.6862	0.6080
10	0.6367	0.7138	0.5917
11	0.6459	0.6949	0.5804
12	0.6866	0.6965	0.5787
13	0.7188	0.6794	0.5820
14	0.7647	0.6908	0.5750
15	0.7498	0.7000	0.5752
16	0.7522	0.6889	0.5757
17	0.7411	0.6662	0.5740
18	0.7382	0.6255	0.5793
19	0.7096	0.6311	0.5875
20	0.7195	0.6628	0.6337
21	0.7475	0.7407	0.7117
22	0.7785	0.7833	0.7730
23	0.7808	0.7769	0.7573
24	0.7985	0.7687	0.7523

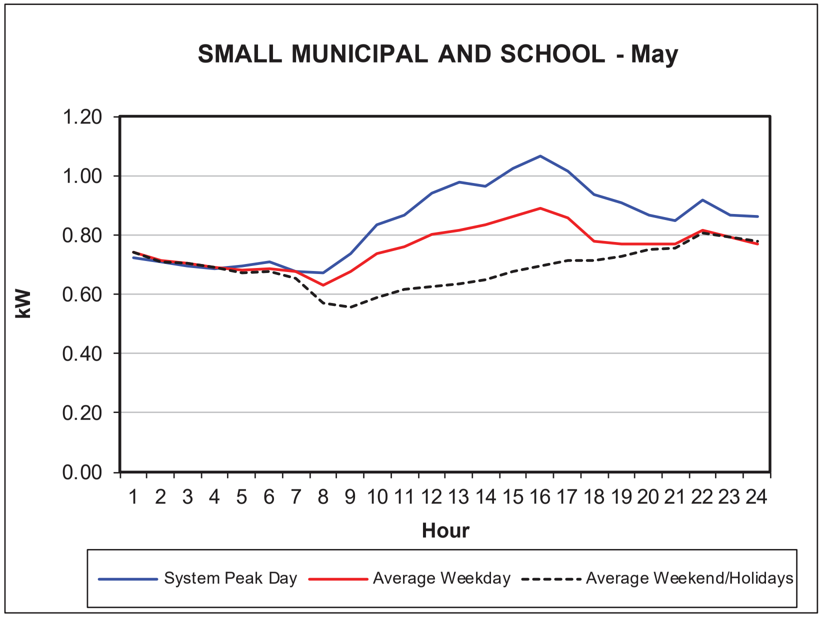


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7247	0.7406	0.7424
2	0.7088	0.7155	0.7099
3	0.6955	0.7039	0.7063
4	0.6850	0.6904	0.6901
5	0.6937	0.6830	0.6710
6	0.7094	0.6852	0.6754
7	0.6763	0.6778	0.6533
8	0.6746	0.6311	0.5721
9	0.7372	0.6750	0.5558
10	0.8328	0.7357	0.5879
11	0.8665	0.7612	0.6183
12	0.9433	0.8011	0.6241
13	0.9776	0.8152	0.6342
14	0.9629	0.8326	0.6502
15	1.0239	0.8608	0.6770
16	1.0659	0.8887	0.6953
17	1.0163	0.8587	0.7131
18	0.9385	0.7772	0.7154
19	0.9101	0.7696	0.7276
20	0.8673	0.7697	0.7506
21	0.8486	0.7691	0.7559
22	0.9180	0.8154	0.8083
23	0.8696	0.7936	0.7924
24	0.8634	0.7707	0.7810

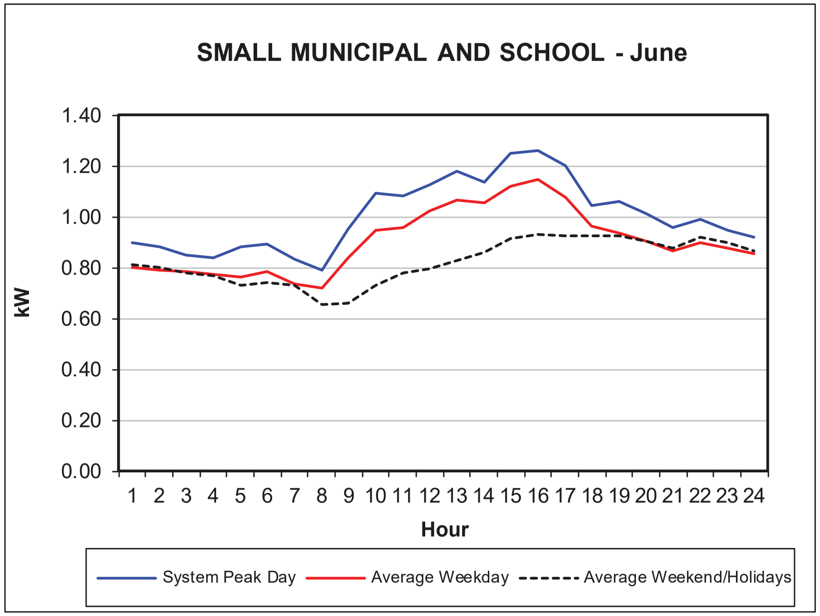


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8981	0.8028	0.8125
2	0.8796	0.7922	0.7981
3	0.8512	0.7848	0.7783
4	0.8408	0.7715	0.7664
5	0.8796	0.7621	0.7317
6	0.8948	0.7847	0.7392
7	0.8351	0.7373	0.7308
8	0.7921	0.7177	0.6560
9	0.9544	0.8380	0.6627
10	1.0951	0.9477	0.7327
11	1.0810	0.9580	0.7795
12	1.1240	1.0229	0.7971
13	1.1809	1.0632	0.8263
14	1.1387	1.0575	0.8621
15	1.2473	1.1198	0.9126
16	1.2608	1.1455	0.9279
17	1.1985	1.0777	0.9255
18	1.0441	0.9636	0.9269
19	1.0628	0.9361	0.9277
20	1.0113	0.9039	0.9026
21	0.9604	0.8672	0.8774
22	0.9891	0.8984	0.9178
23	0.9464	0.8786	0.9006
24	0.9187	0.8523	0.8659

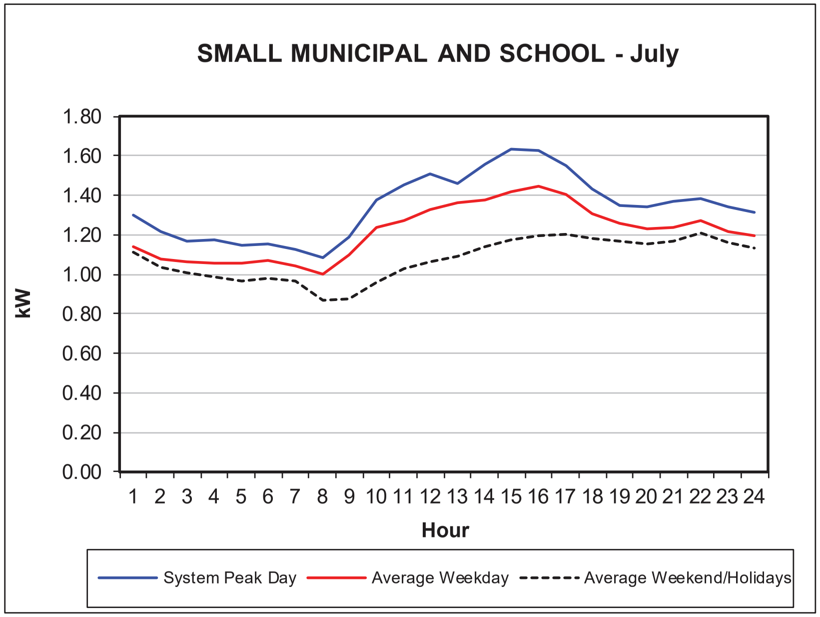


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.2983	1.1395	1.1096
2	1.2141	1.0781	1.0344
3	1.1675	1.0621	1.0105
4	1.1743	1.0544	0.9847
5	1.1492	1.0551	0.9646
6	1.1550	1.0716	0.9803
7	1.1262	1.0390	0.9673
8	1.0843	1.0013	0.8711
9	1.1873	1.1011	0.8726
10	1.3748	1.2340	0.9590
11	1.4525	1.2711	1.0312
12	1.5058	1.3277	1.0612
13	1.4607	1.3610	1.0930
14	1.5588	1.3769	1.1402
15	1.6303	1.4202	1.1716
16	1.6239	1.4478	1.1936
17	1.5466	1.4054	1.2007
18	1.4334	1.3091	1.1785
19	1.3494	1.2567	1.1661
20	1.3436	1.2325	1.1560
21	1.3706	1.2335	1.1676
22	1.3826	1.2698	1.2079
23	1.3414	1.2186	1.1626
24	1.3112	1.1958	1.1330

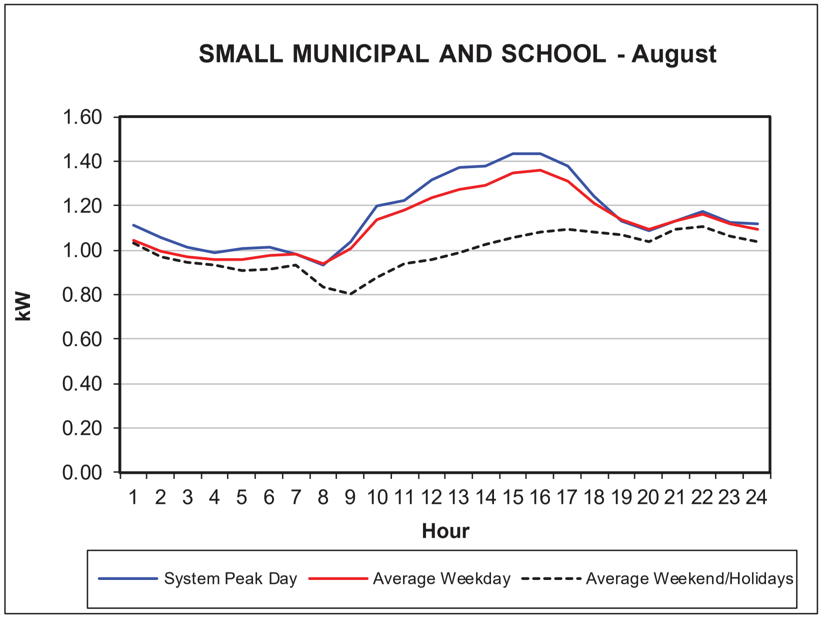


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1096	1.0448	1.0322
2	1.0544	0.9920	0.9709
3	1.0098	0.9709	0.9426
4	0.9904	0.9583	0.9298
5	1.0054	0.9601	0.9055
6	1.0146	0.9761	0.9121
7	0.9810	0.9791	0.9300
8	0.9308	0.9379	0.8343
9	1.0404	1.0056	0.7995
10	1.1959	1.1351	0.8770
11	1.2204	1.1777	0.9364
12	1.3137	1.2323	0.9601
13	1.3737	1.2717	0.9851
14	1.3791	1.2940	1.0221
15	1.4321	1.3449	1.0530
16	1.4338	1.3586	1.0814
17	1.3803	1.3108	1.0935
18	1.2425	1.2110	1.0801
19	1.1290	1.1375	1.0664
20	1.0896	1.0914	1.0392
21	1.1299	1.1308	1.0932
22	1.1709	1.1584	1.1025
23	1.1252	1.1187	1.0643
24	1.1189	1.0958	1.0378

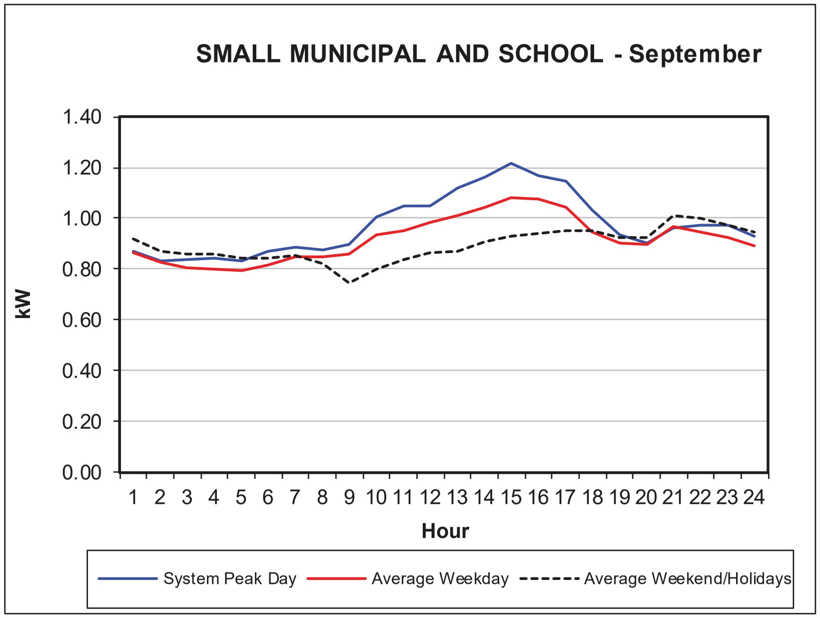


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8688	0.8649	0.9205
2	0.8299	0.8257	0.8712
3	0.8367	0.8069	0.8610
4	0.8410	0.7982	0.8598
5	0.8312	0.7947	0.8425
6	0.8698	0.8166	0.8433
7	0.8839	0.8481	0.8536
8	0.8729	0.8503	0.8187
9	0.8951	0.8608	0.7432
10	1.0048	0.9351	0.8001
11	1.0507	0.9498	0.8363
12	1.0480	0.9831	0.8626
13	1.1178	1.0124	0.8710
14	1.1643	1.0418	0.9092
15	1.2144	1.0828	0.9320
16	1.1697	1.0737	0.9401
17	1.1441	1.0407	0.9492
18	1.0316	0.9449	0.9489
19	0.9337	0.9036	0.9233
20	0.9048	0.8945	0.9267
21	0.9612	0.9693	1.0127
22	0.9746	0.9469	0.9978
23	0.9709	0.9267	0.9733
24	0.9270	0.8909	0.9469

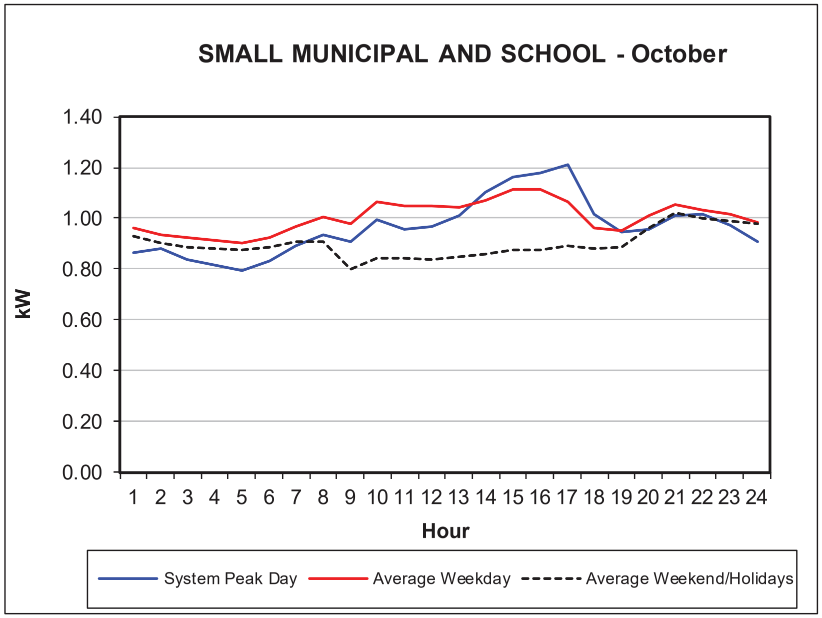


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8624	0.9599	0.9300
2	0.8834	0.9368	0.9044
3	0.8359	0.9214	0.8878
4	0.8179	0.9117	0.8804
5	0.7964	0.9035	0.8748
6	0.8344	0.9228	0.8847
7	0.8894	0.9655	0.9059
8	0.9332	1.0038	0.9060
9	0.9077	0.9800	0.8016
10	0.9965	1.0654	0.8422
11	0.9566	1.0460	0.8455
12	0.9665	1.0489	0.8376
13	1.0130	1.0436	0.8458
14	1.1013	1.0727	0.8612
15	1.1627	1.1117	0.8731
16	1.1793	1.1109	0.8763
17	1.2092	1.0648	0.8927
18	1.0137	0.9642	0.8823
19	0.9477	0.9513	0.8867
20	0.9579	1.0091	0.9636
21	1.0112	1.0535	1.0194
22	1.0166	1.0299	0.9978
23	0.9708	1.0136	0.9911
24	0.9070	0.9826	0.9763

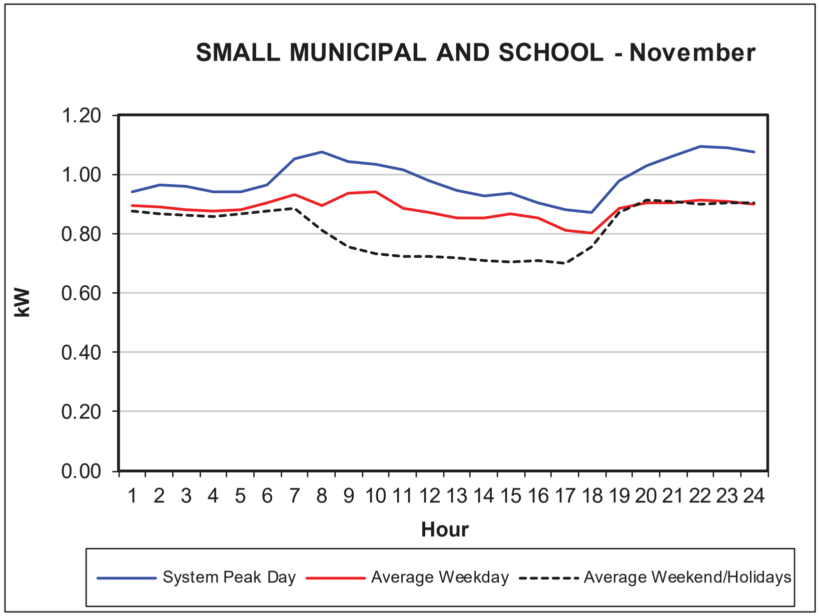


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9397	0.8947	0.8769
2	0.9652	0.8910	0.8678
3	0.9592	0.8832	0.8607
4	0.9431	0.8780	0.8601
5	0.9393	0.8822	0.8683
6	0.9626	0.9041	0.8750
7	1.0527	0.9313	0.8850
8	1.0747	0.8960	0.8126
9	1.0442	0.9365	0.7550
10	1.0342	0.9428	0.7329
11	1.0169	0.8875	0.7247
12	0.9780	0.8717	0.7224
13	0.9452	0.8542	0.7177
14	0.9267	0.8516	0.7103
15	0.9369	0.8676	0.7066
16	0.9039	0.8517	0.7097
17	0.8816	0.8100	0.6988
18	0.8708	0.8007	0.7566
19	0.9792	0.8842	0.8696
20	1.0295	0.9066	0.9118
21	1.0606	0.9035	0.9105
22	1.0959	0.9116	0.8984
23	1.0894	0.9081	0.9029
24	1.0766	0.9015	0.9062

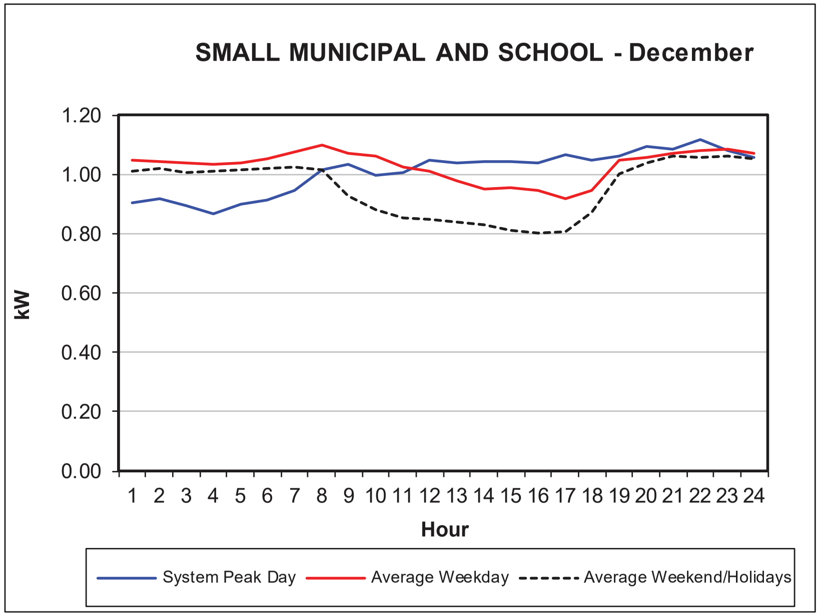


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-3.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9062	1.0467	1.0091
2	0.9176	1.0432	1.0202
3	0.8937	1.0404	1.0081
4	0.8676	1.0345	1.0125
5	0.9009	1.0388	1.0142
6	0.9157	1.0542	1.0205
7	0.9456	1.0777	1.0248
8	1.0138	1.0983	1.0153
9	1.0344	1.0724	0.9268
10	0.9979	1.0612	0.8815
11	1.0052	1.0235	0.8543
12	1.0485	1.0090	0.8496
13	1.0389	0.9773	0.8415
14	1.0414	0.9502	0.8298
15	1.0435	0.9550	0.8129
16	1.0366	0.9453	0.8041
17	1.0690	0.9192	0.8076
18	1.0458	0.9452	0.8727
19	1.0601	1.0483	1.0031
20	1.0924	1.0590	1.0386
21	1.0841	1.0699	1.0616
22	1.1162	1.0818	1.0591
23	1.0792	1.0867	1.0631
24	1.0578	1.0726	1.0505

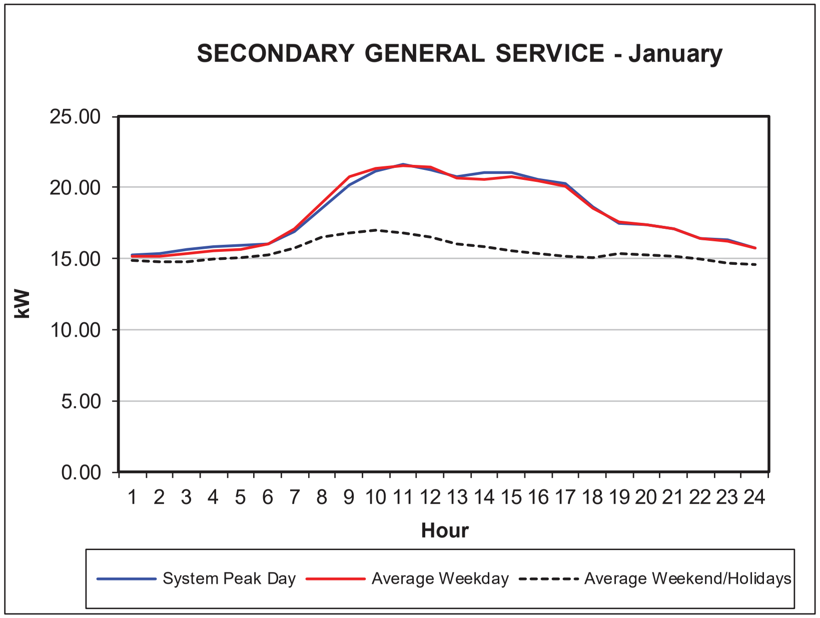


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.2726	15.2170	14.8479
2	15.4055	15.1932	14.7490
3	15.6165	15.3325	14.7857
4	15.8124	15.5211	14.9497
5	15.9068	15.6572	15.0431
6	16.0401	16.0633	15.2730
7	16.8895	17.0919	15.7583
8	18.5711	18.9468	16.5506
9	20.2153	20.7257	16.8403
10	21.1552	21.3788	16.9591
11	21.6742	21.5312	16.8331
12	21.2004	21.4187	16.4983
13	20.7918	20.6185	15.9976
14	21.0936	20.5908	15.8724
15	21.0499	20.7696	15.5976
16	20.5462	20.4571	15.3526
17	20.2793	20.1148	15.1600
18	18.6112	18.5690	15.1099
19	17.4620	17.6049	15.3528
20	17.3914	17.3815	15.2660
21	17.0728	17.0489	15.1705
22	16.4571	16.4574	14.9347
23	16.3690	16.2258	14.7060
24	15.7624	15.7576	14.5916



Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.0460	15.7999	14.8143
2	16.0199	15.7441	14.5902
3	15.9568	15.8857	14.5699
4	16.1197	16.1091	14.7684
5	16.0163	16.2152	14.8930
6	16.4662	16.5855	15.2014
7	17.2548	17.4664	15.6450
8	18.8598	19.2109	16.1753
9	20.6698	20.5669	16.3443
10	21.7931	21.3623	16.5194
11	22.1543	21.4820	16.4331
12	21.8881	21.4719	16.3822
13	21.0383	20.7534	16.1220
14	21.3401	20.9676	16.0323
15	21.3747	20.9271	15.6814
16	21.1110	20.5446	15.4227
17	20.5485	20.1906	15.2697
18	18.4035	18.7961	15.0779
19	17.2860	18.0075	15.0196
20	17.4395	17.9783	15.0395
21	16.9057	17.6202	14.7835
22	16.0159	17.0008	14.6105
23	15.8087	16.6990	14.4839
24	15.3841	16.3262	14.3629

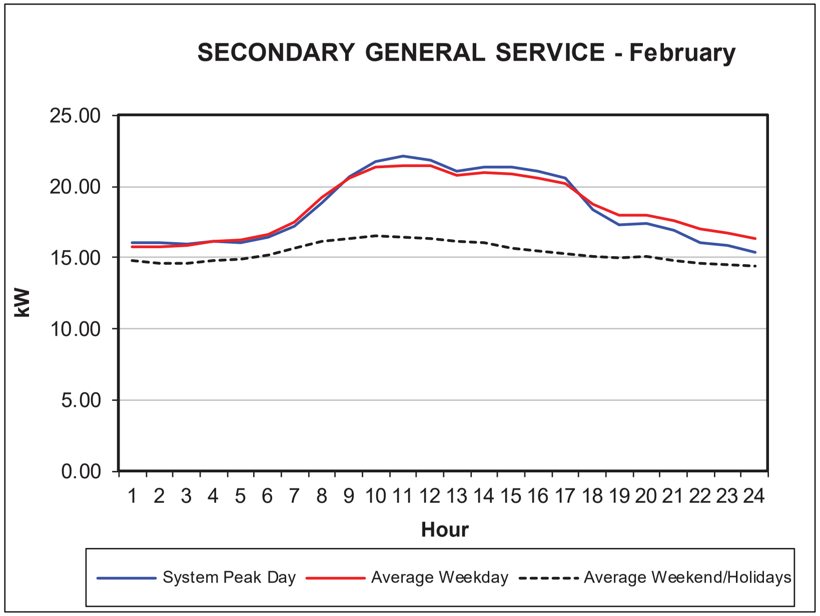
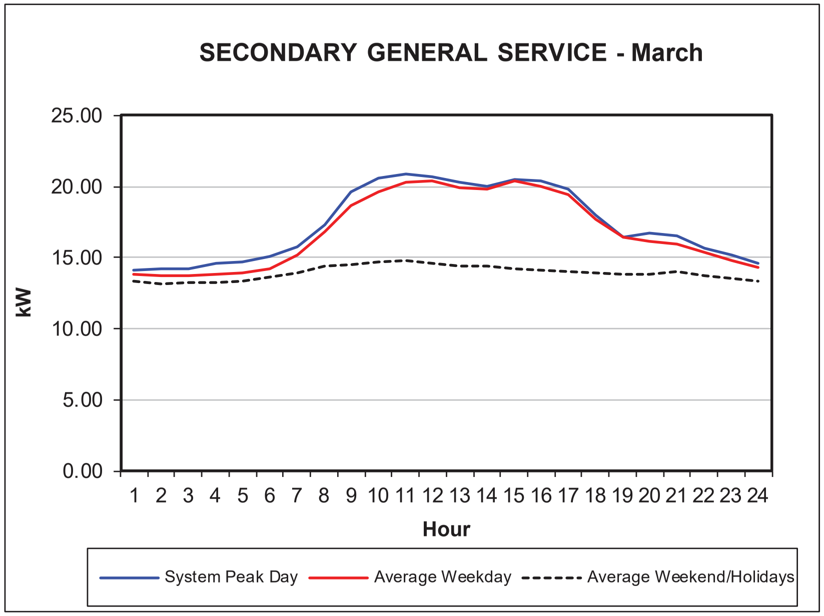


TABLE E-4.3

Southwestern Public Service Company
Hourly Load Profiles

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14.0723	13.8322	13.3554
2	14.1704	13.6876	13.1743
3	14.2272	13.7010	13.2017
4	14.5753	13.8079	13.2293
5	14.6930	13.8954	13.3450
6	15.0872	14.2230	13.5988
7	15.7406	15.1480	13.9138
8	17.3124	16.7837	14.3752
9	19.5837	18.6482	14.4671
10	20.5344	19.6388	14.6889
11	20.8983	20.2545	14.7549
12	20.6685	20.3986	14.6361
13	20.3060	19.8710	14.3558
14	19.9527	19.8420	14.3482
15	20.5115	20.3617	14.1766
16	20.3460	20.0366	14.0614
17	19.8316	19.4543	13.9645
18	17.9325	17.6557	13.8818
19	16.4566	16.3789	13.8143
20	16.6837	16.1075	13.8557
21	16.4961	15.9892	13.9704
22	15.6588	15.3484	13.6901
23	15.1287	14.8253	13.5105
24	14.5766	14.3247	13.2899

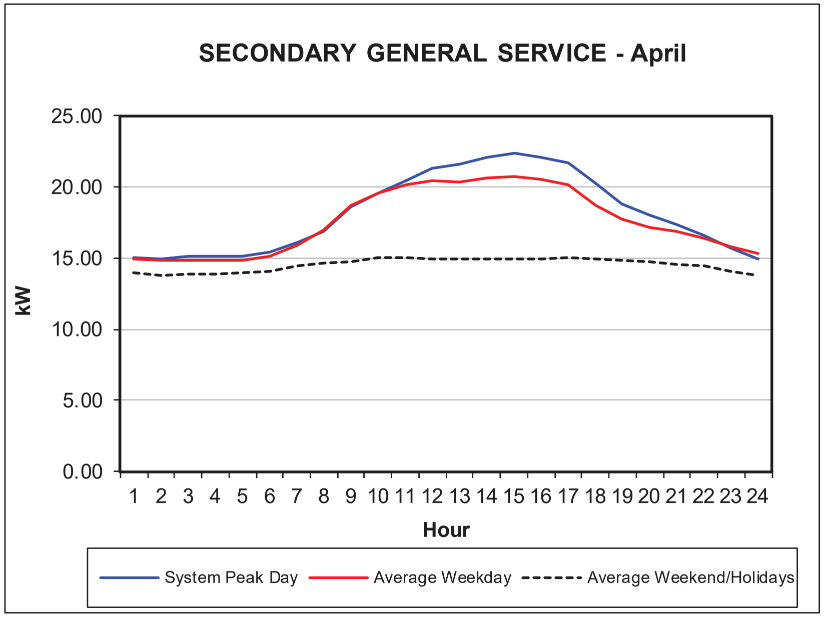


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.0350	14.9009	13.9562
2	14.9804	14.8042	13.8084
3	15.1095	14.8167	13.8274
4	15.1714	14.8676	13.8909
5	15.1306	14.8497	13.9333
6	15.4287	15.1165	14.0560
7	16.0770	15.9460	14.4509
8	16.8216	17.0126	14.6483
9	18.6438	18.6617	14.7820
10	19.6033	19.5888	15.0036
11	20.4215	20.1587	15.0374
12	21.2998	20.4225	14.9801
13	21.5633	20.3321	14.8938
14	22.0918	20.5926	14.8920
15	22.3878	20.7280	14.9587
16	22.1045	20.5321	14.9457
17	21.7197	20.1101	15.0221
18	20.2515	18.7018	14.8893
19	18.7803	17.7616	14.8457
20	18.0014	17.1665	14.6969
21	17.3824	16.9120	14.5936
22	16.5850	16.4154	14.4188
23	15.6911	15.8499	14.1013
24	14.8909	15.3537	13.7444

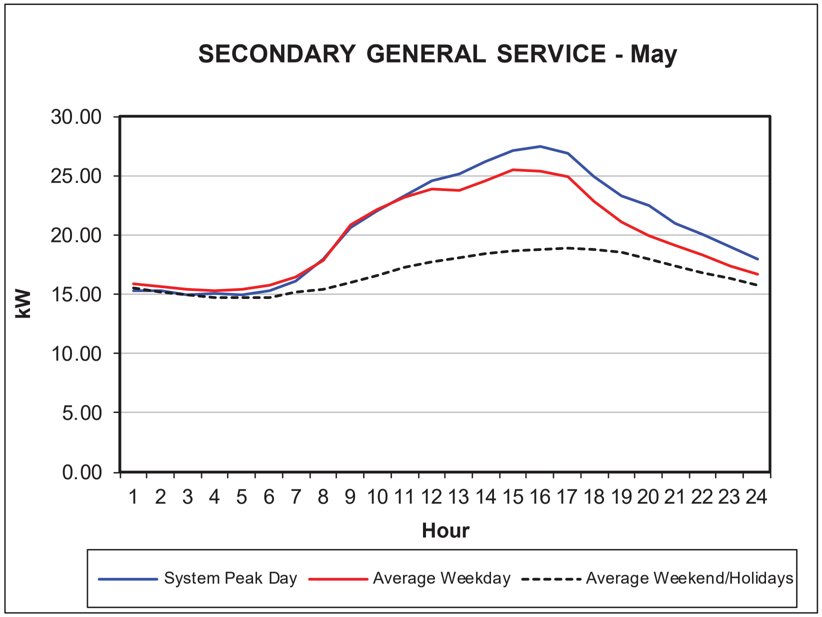


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.3496	15.9131	15.5749
2	15.2591	15.6354	15.1526
3	14.9522	15.3762	14.9108
4	15.0299	15.3366	14.7633
5	15.0117	15.3670	14.6686
6	15.3313	15.7531	14.7693
7	16.1539	16.4961	15.1836
8	17.9755	17.8486	15.3866
9	20.6827	20.8326	15.9480
10	22.0448	22.1658	16.5870
11	23.2800	23.2348	17.2558
12	24.5383	23.8748	17.7083
13	25.1285	23.7841	18.0497
14	26.2567	24.6200	18.3874
15	27.1407	25.5323	18.6646
16	27.4786	25.3436	18.8144
17	26.9240	24.8771	18.9146
18	24.9449	22.8533	18.7453
19	23.3486	21.0454	18.4980
20	22.5037	19.9894	17.9253
21	21.0197	19.1646	17.3386
22	20.0823	18.3152	16.8624
23	19.0003	17.3816	16.3894
24	18.0070	16.6757	15.7915

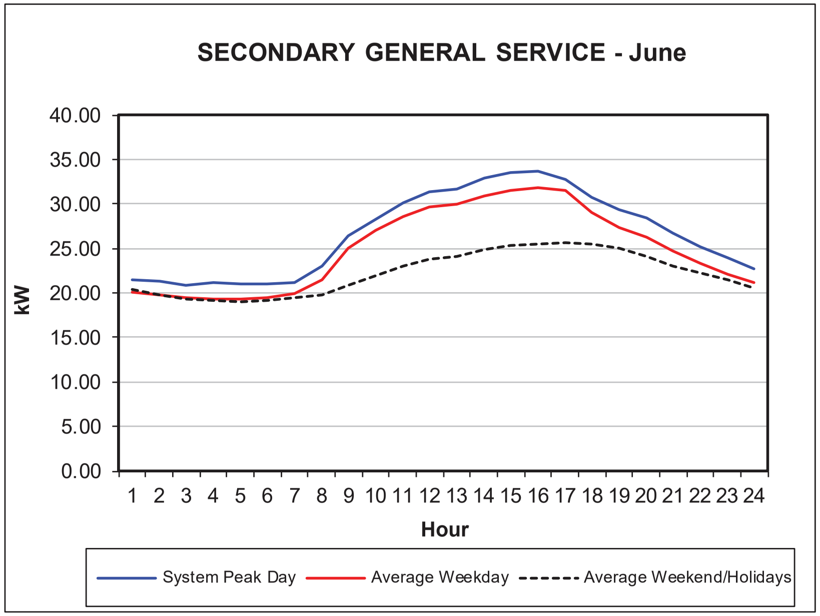


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	21.4623	20.1162	20.3803
2	21.2842	19.7787	19.8593
3	20.8705	19.4428	19.3766
4	21.1328	19.3487	19.1007
5	21.0979	19.2669	19.0172
6	20.9660	19.4369	19.1996
7	21.1860	20.0065	19.4733
8	23.0561	21.4862	19.7639
9	26.4547	24.9905	20.8299
10	28.2578	27.0143	21.9653
11	30.1139	28.5412	23.0589
12	31.3355	29.6973	23.8059
13	31.7676	29.9847	24.1241
14	32.9102	30.9491	24.8437
15	33.5353	31.5890	25.4074
16	33.6783	31.7844	25.5024
17	32.7254	31.4752	25.6883
18	30.8194	29.0142	25.5719
19	29.3014	27.3250	25.0658
20	28.3753	26.2143	24.1280
21	26.7726	24.7901	23.0071
22	25.1852	23.4069	22.3113
23	23.9132	22.0551	21.4170
24	22.7452	21.1494	20.6253

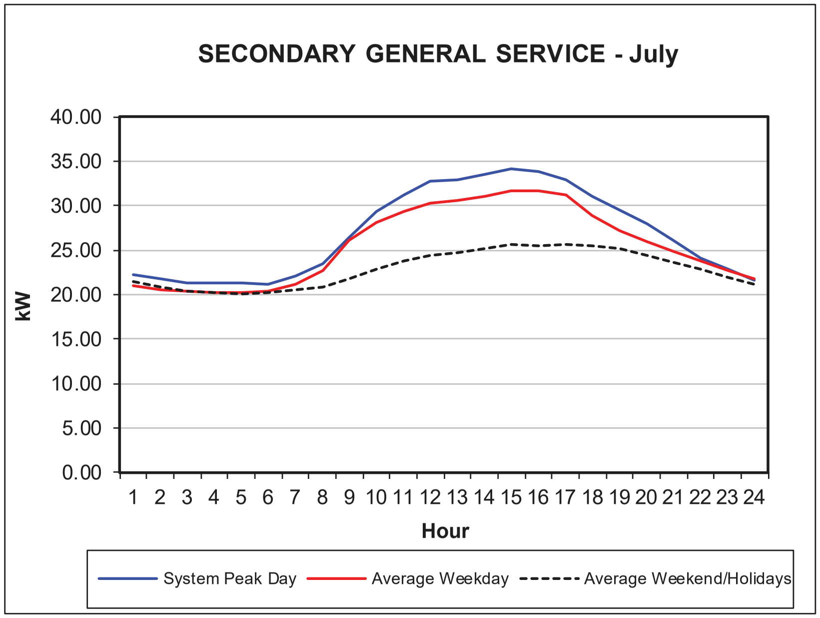


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	22.1574	20.9267	21.4017
2	21.8375	20.5742	20.8652
3	21.2933	20.3205	20.4495
4	21.3594	20.2372	20.2019
5	21.2524	20.2430	20.1258
6	21.1035	20.3910	20.1429
7	22.0423	21.1052	20.5934
8	23.3888	22.6820	20.8225
9	26.3995	26.1330	21.7261
10	29.2672	28.1018	22.7784
11	31.1669	29.3691	23.7766
12	32.7479	30.3349	24.3296
13	32.9138	30.6377	24.6478
14	33.4514	31.0251	25.1173
15	34.1093	31.7228	25.5605
16	33.8679	31.6404	25.4024
17	32.8210	31.2491	25.6123
18	30.9691	28.8587	25.5203
19	29.4653	27.1885	25.1120
20	27.9434	26.0110	24.3956
21	26.0486	24.8999	23.6046
22	24.0145	23.7085	22.8618
23	22.7849	22.6428	21.9122
24	21.6137	21.8335	21.1813

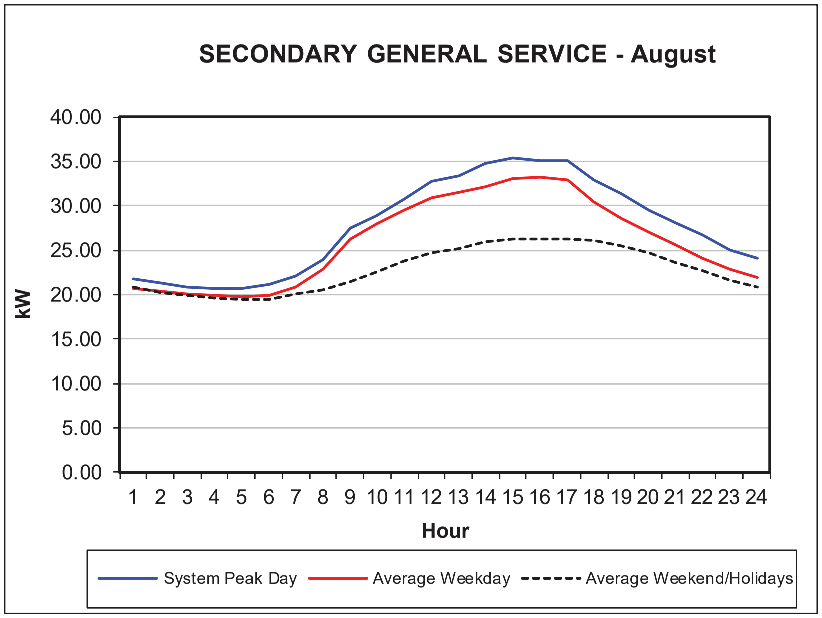


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	21.7811	20.6865	20.7999
2	21.2370	20.2996	20.2256
3	20.8568	20.0014	19.8664
4	20.6326	19.8584	19.5571
5	20.6071	19.6934	19.3748
6	21.1213	19.9472	19.4065
7	22.0731	20.8393	20.0461
8	23.8735	22.9104	20.5652
9	27.5025	26.2407	21.3997
10	28.8302	27.9447	22.5534
11	30.8058	29.5355	23.7528
12	32.6850	30.8375	24.7033
13	33.4300	31.5110	25.2088
14	34.7436	32.0583	25.8770
15	35.3206	33.1033	26.2007
16	34.9852	33.2373	26.2022
17	35.0414	32.8775	26.2652
18	32.8430	30.4407	26.0299
19	31.2753	28.4957	25.5110
20	29.5551	27.0198	24.6449
21	28.0936	25.5688	23.6707
22	26.7007	24.1600	22.7483
23	25.0216	22.9039	21.5716
24	24.0915	21.9465	20.7994

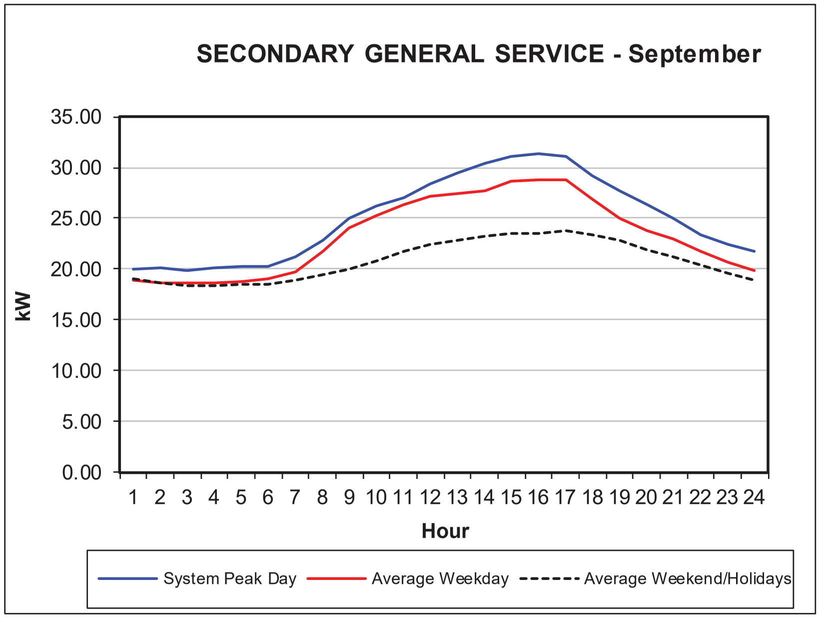


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.9436	18.9726	18.9788
2	20.1193	18.6839	18.6038
3	19.8627	18.5910	18.4300
4	20.0614	18.6774	18.3861
5	20.2060	18.8142	18.4666
6	20.2422	19.0398	18.5476
7	21.1911	19.7134	18.8809
8	22.8252	21.7690	19.5109
9	24.9414	24.0943	19.9406
10	26.2673	25.2519	20.8523
11	27.0444	26.3184	21.7740
12	28.4164	27.1214	22.4874
13	29.5141	27.4472	22.8442
14	30.4667	27.6858	23.2659
15	31.1317	28.6464	23.5037
16	31.3571	28.7529	23.5739
17	31.1316	28.7163	23.7165
18	29.1267	26.9482	23.4294
19	27.6585	25.0574	22.8105
20	26.2845	23.8369	21.8611
21	25.0198	22.9189	21.1645
22	23.4287	21.7216	20.3962
23	22.4526	20.6416	19.5405
24	21.6954	19.8548	18.8457

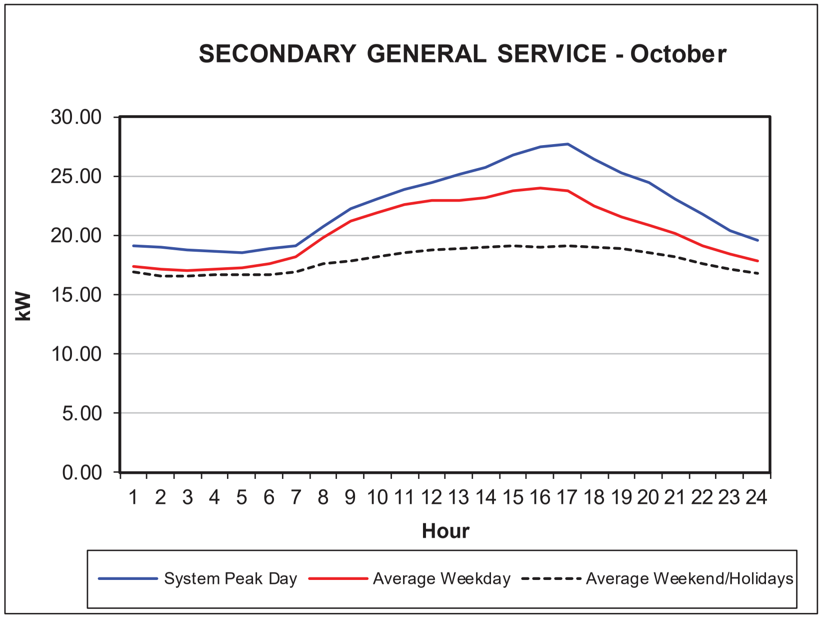


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.1245	17.3962	16.8470
2	18.9904	17.1906	16.6024
3	18.7347	17.0543	16.5782
4	18.6302	17.1448	16.6603
5	18.5548	17.2913	16.6430
6	18.8824	17.6070	16.7102
7	19.1588	18.1781	16.9593
8	20.7834	19.7801	17.5620
9	22.2297	21.1366	17.8445
10	23.0055	21.8415	18.1377
11	23.8939	22.5675	18.4864
12	24.3951	22.8937	18.7200
13	25.1149	22.9790	18.8344
14	25.7474	23.1652	18.9826
15	26.7351	23.7262	19.0486
16	27.4536	23.9514	18.9954
17	27.6855	23.7336	19.1338
18	26.3742	22.5060	19.0055
19	25.2440	21.4966	18.8295
20	24.4035	20.8094	18.5692
21	23.0986	20.0956	18.1543
22	21.7411	19.1324	17.6489
23	20.3246	18.3893	17.1626
24	19.6260	17.7963	16.7551

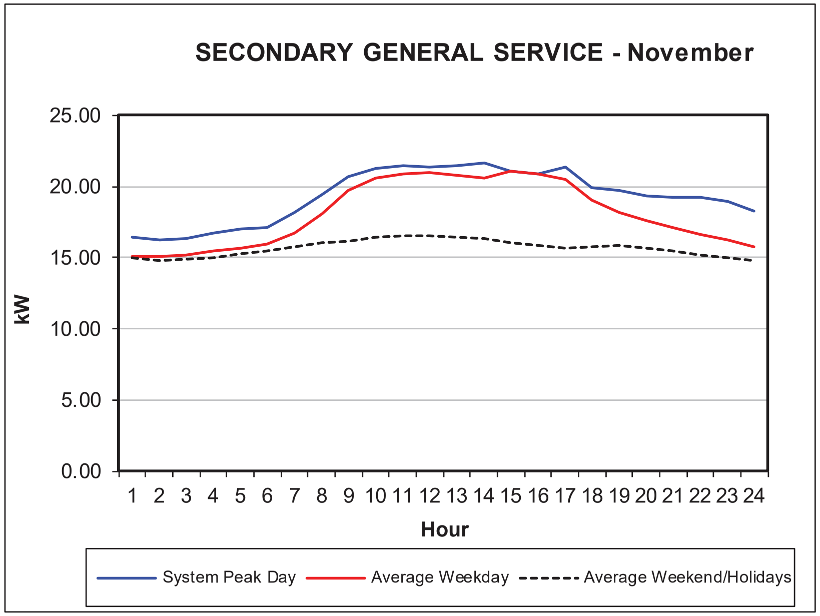


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.3874	15.1103	14.9904
2	16.2223	15.0920	14.7945
3	16.3625	15.1702	14.8978
4	16.7286	15.4480	14.9670
5	17.0090	15.6547	15.2926
6	17.1110	15.9831	15.4857
7	18.1488	16.7071	15.7876
8	19.4009	18.0958	16.0450
9	20.7140	19.6625	16.0972
10	21.2409	20.6232	16.4061
11	21.4888	20.9028	16.4821
12	21.3280	20.9474	16.4988
13	21.4599	20.7400	16.4104
14	21.5959	20.6144	16.3018
15	21.1107	21.0274	16.0715
16	20.8674	20.8422	15.8892
17	21.3714	20.4490	15.6744
18	19.8731	19.0617	15.7381
19	19.7476	18.1433	15.8821
20	19.3064	17.6039	15.6582
21	19.2709	17.1060	15.4389
22	19.1795	16.5801	15.1461
23	18.9629	16.2419	14.9424
24	18.2839	15.7870	14.7518

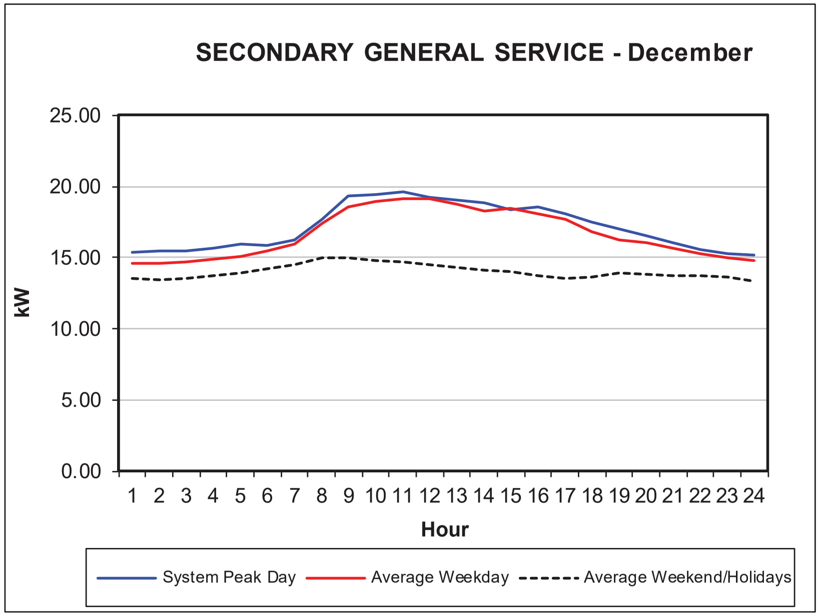


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-4.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.4101	14.5412	13.5483
2	15.4516	14.5584	13.4420
3	15.4332	14.6667	13.4944
4	15.6882	14.8583	13.7037
5	15.9017	15.0765	13.8907
6	15.8732	15.4161	14.1968
7	16.2690	15.9421	14.5041
8	17.7043	17.3535	14.9651
9	19.2984	18.5517	14.9661
10	19.4615	18.9682	14.8136
11	19.5707	19.1561	14.6508
12	19.2356	19.1150	14.5115
13	19.0267	18.7161	14.2757
14	18.8554	18.2781	14.1383
15	18.4013	18.4083	13.9815
16	18.5099	18.0948	13.7450
17	18.0652	17.6538	13.5183
18	17.4531	16.8068	13.5983
19	16.9869	16.2163	13.8925
20	16.4997	15.9911	13.8273
21	16.0261	15.6841	13.7303
22	15.5373	15.2875	13.7045
23	15.2749	15.0207	13.6023
24	15.1352	14.7458	13.3636

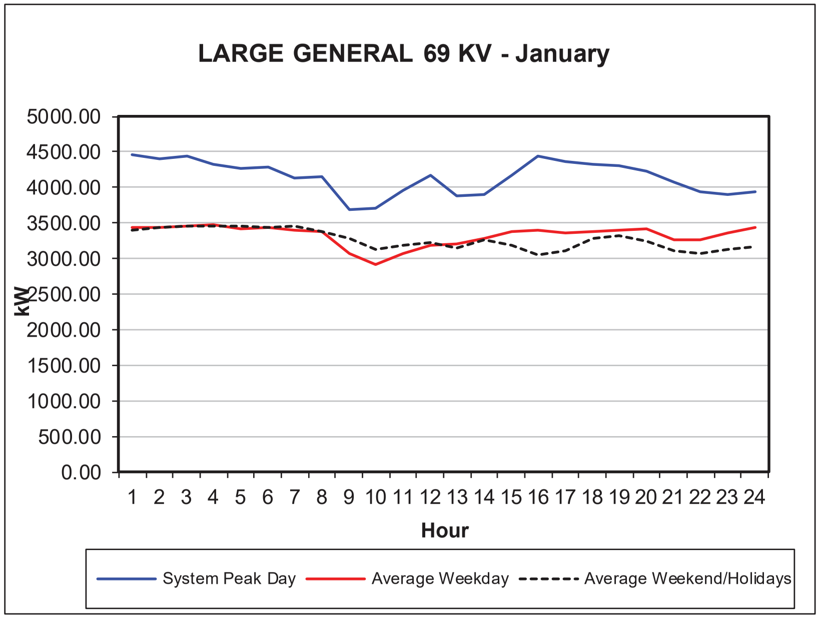


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4455.7506	3439.7366	3406.3181
2	4403.2039	3434.0839	3437.5011
3	4447.0684	3460.6889	3461.3765
4	4334.9121	3472.8525	3458.5481
5	4263.1038	3422.1796	3452.4322
6	4284.7681	3432.8470	3429.6842
7	4140.4717	3402.3605	3456.0075
8	4153.5583	3386.0214	3375.3107
9	3682.9860	3066.9415	3275.2444
10	3704.0861	2918.3329	3127.0051
11	3950.2028	3073.3775	3179.2134
12	4178.7130	3182.9957	3227.8796
13	3891.0256	3211.9167	3140.9772
14	3909.4678	3293.3880	3259.2900
15	4165.7343	3374.5483	3191.0024
16	4449.0807	3406.6991	3054.9147
17	4359.8083	3360.8749	3111.5450
18	4330.8643	3388.0233	3284.4192
19	4306.9491	3403.0257	3318.4709
20	4231.2215	3411.4127	3241.4048
21	4080.2855	3264.9975	3112.9522
22	3948.3886	3256.9130	3078.8661
23	3896.7943	3358.9208	3121.6180
24	3944.5087	3445.4316	3178.0140

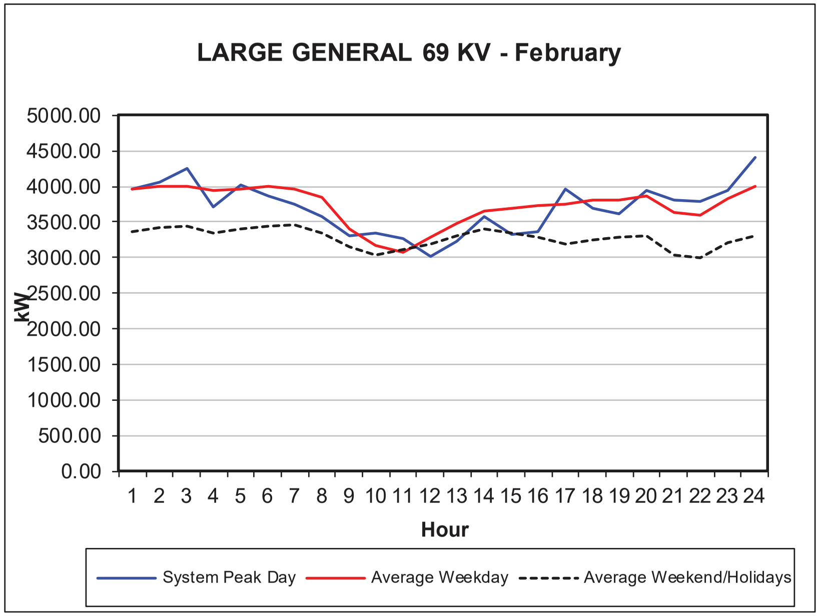


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3956.3062	3967.6374	3364.6183
2	4055.4645	3993.2020	3418.7890
3	4247.2177	4008.4633	3438.0247
4	3706.4009	3948.6995	3345.5429
5	4030.3604	3961.5094	3406.7505
6	3860.7447	3994.3540	3432.9548
7	3747.8198	3962.1629	3461.8728
8	3580.7649	3840.5897	3342.4932
9	3310.8539	3402.1342	3149.3503
10	3338.2149	3178.5938	3040.6700
11	3265.0803	3083.1557	3104.6453
12	3009.5758	3292.5559	3186.6075
13	3237.5400	3485.5719	3308.5308
14	3581.1688	3663.0426	3393.6450
15	3330.2803	3693.1517	3347.0266
16	3356.1160	3730.4923	3280.8189
17	3956.6016	3741.7512	3190.3672
18	3700.6350	3805.4359	3240.9635
19	3616.2072	3810.5765	3290.1768
20	3945.8602	3862.5583	3299.5839
21	3805.5351	3634.1116	3043.2228
22	3784.6810	3605.8152	3000.9687
23	3945.8602	3821.6675	3205.2909
24	4403.2790	4010.5883	3304.9618

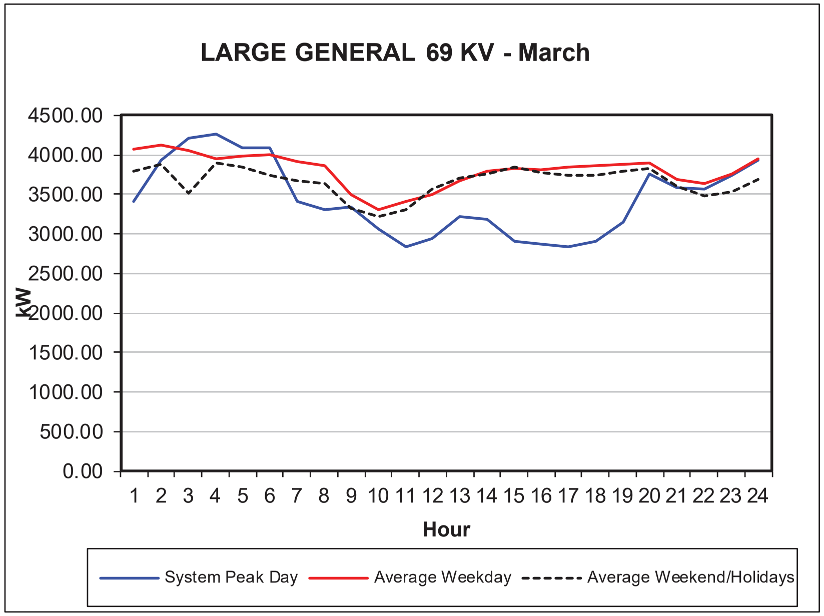


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3416.4691	4070.3821	3797.8942
2	3931.9259	4113.5453	3886.4071
3	4210.2163	4060.1737	3513.3961
4	4258.0286	3950.6021	3899.5696
5	4089.9389	3977.8513	3837.1416
6	4084.2013	3996.0158	3745.2842
7	3412.2245	3918.9351	3674.2705
8	3296.7688	3861.5015	3631.2770
9	3345.6298	3499.3440	3320.3542
10	3058.6011	3311.1277	3213.0893
11	2835.5210	3402.5068	3310.5828
12	2945.5312	3494.1582	3570.7585
13	3221.1824	3676.9320	3698.2592
14	3178.2692	3789.2273	3752.1566
15	2909.3133	3817.4293	3840.0753
16	2876.2495	3800.7498	3765.6150
17	2842.9487	3835.4081	3743.6532
18	2912.9738	3859.4159	3744.6723
19	3140.1584	3881.3810	3785.4740
20	3755.2753	3890.0475	3825.0699
21	3581.1407	3692.1730	3600.4706
22	3559.7579	3630.7796	3478.6093
23	3736.3615	3757.2802	3530.0124
24	3927.2615	3944.5600	3685.7633

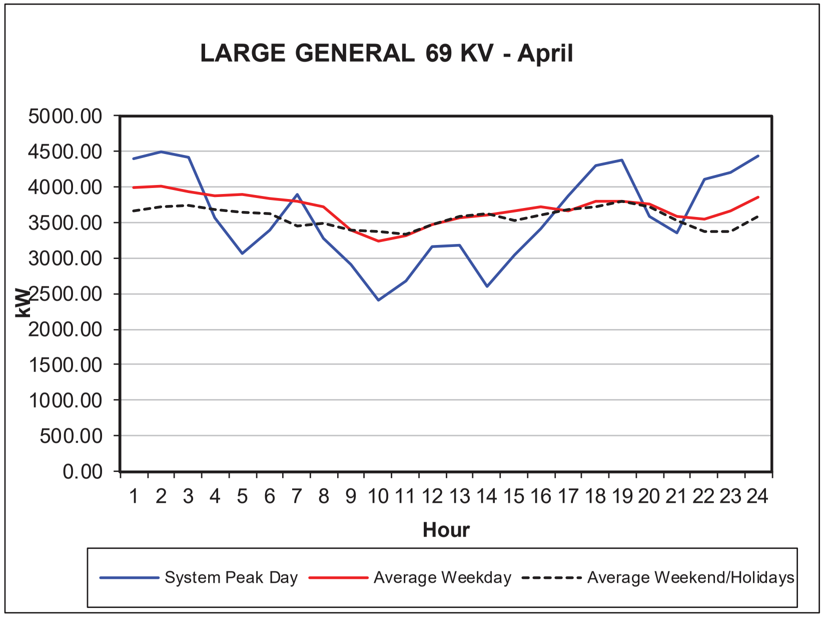


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4402.2557	3996.9522	3657.7647
2	4490.2791	4007.9300	3724.4790
3	4422.2407	3939.3102	3749.6923
4	3559.7345	3880.5490	3681.3930
5	3057.3407	3887.1825	3639.3812
6	3392.5803	3832.0417	3616.7071
7	3890.1320	3803.0958	3449.0001
8	3281.3791	3724.6195	3496.3311
9	2914.1037	3392.4149	3400.7198
10	2405.1125	3239.4455	3377.9126
11	2670.1690	3307.2214	3341.4220
12	3169.4226	3471.9736	3478.7181
13	3179.3507	3571.8626	3587.9743
14	2607.4353	3603.4485	3622.0608
15	3045.0293	3672.6105	3534.8212
16	3413.0059	3720.2442	3606.6377
17	3871.4846	3671.6228	3691.2015
18	4306.2290	3793.7549	3716.8897
19	4375.1621	3791.9118	3806.6188
20	3578.2220	3758.7772	3715.3114
21	3345.8626	3594.0867	3532.3235
22	4102.5614	3556.3302	3374.5309
23	4210.2764	3659.4804	3376.5060
24	4436.6478	3859.4884	3581.2742

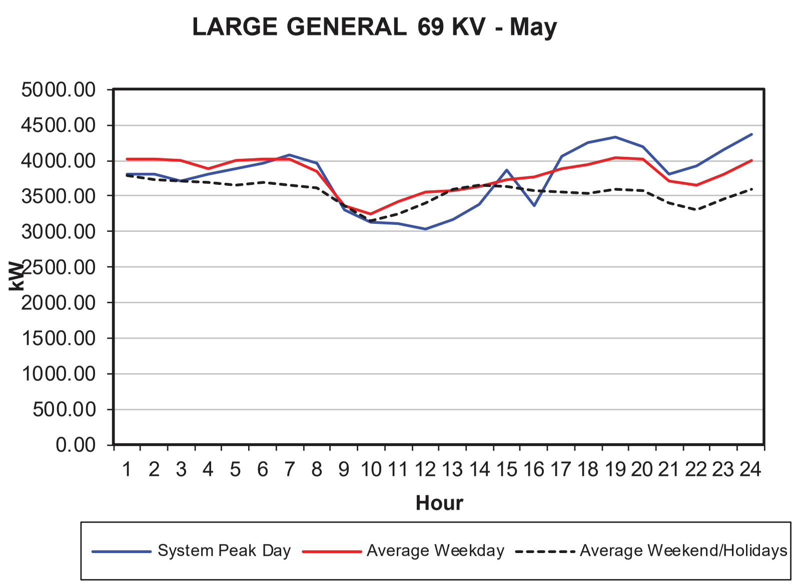


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3803.9881	4009.8562	3783.9282
2	3808.4087	4021.0448	3737.5701
3	3713.5017	4008.5495	3712.6117
4	3801.7891	3890.6312	3689.8516
5	3888.1604	3996.1830	3657.0969
6	3964.2678	4028.3880	3689.0819
7	4069.0749	4010.7700	3648.8710
8	3970.5650	3840.1860	3619.0611
9	3308.1381	3360.0200	3356.0701
10	3124.0015	3245.8195	3158.8937
11	3118.8278	3412.9281	3252.8303
12	3029.9310	3563.1892	3403.0321
13	3168.2242	3581.6762	3594.0629
14	3381.8473	3628.7796	3645.4910
15	3867.5014	3729.1310	3625.7915
16	3370.2343	3768.6416	3583.0229
17	4054.4785	3876.4268	3550.6678
18	4256.5942	3934.7247	3535.7970
19	4329.5655	4047.6297	3601.5500
20	4191.8063	4014.0077	3578.3472
21	3814.8663	3709.9048	3404.7945
22	3929.1064	3644.3055	3299.3814
23	4156.5057	3802.6995	3459.4619
24	4359.9777	3996.7816	3585.0447

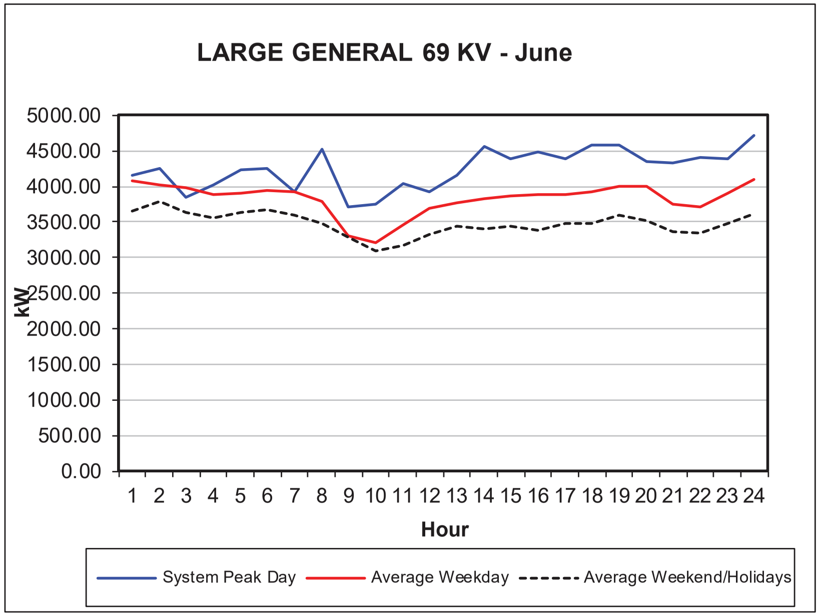


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4150.8300	4071.3377	3658.1935
2	4258.7905	4016.7471	3780.3921
3	3846.2927	3981.9549	3636.9208
4	4018.1992	3889.8026	3551.7182
5	4237.5604	3899.6302	3623.5454
6	4244.7481	3944.4021	3672.0392
7	3931.2887	3923.8005	3602.0823
8	4524.6610	3789.2141	3484.0265
9	3716.4693	3305.1815	3292.4975
10	3755.9004	3213.2332	3094.1356
11	4033.0935	3466.2792	3162.3916
12	3916.4184	3685.1706	3322.5385
13	4150.1449	3772.9006	3448.9534
14	4565.9111	3827.0092	3391.9053
15	4386.1540	3859.1951	3436.1469
16	4480.5050	3888.8118	3383.2508
17	4381.1622	3892.3080	3470.8915
18	4571.3160	3921.8195	3475.2502
19	4577.3211	3991.7703	3590.7683
20	4357.1961	3994.0383	3521.4123
21	4328.5959	3748.1586	3362.2364
22	4401.0342	3719.2927	3335.4412
23	4379.9276	3908.4417	3475.7923
24	4708.5727	4095.0516	3621.1996

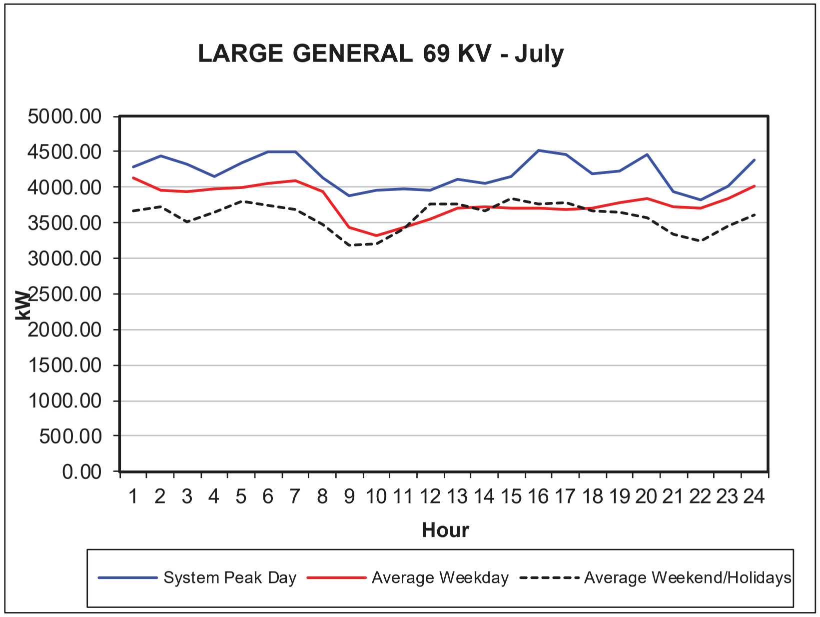


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4276.5044	4136.6812	3661.9038
2	4447.6866	3954.9345	3726.3505
3	4322.8885	3947.4673	3505.6641
4	4155.5880	3968.3393	3651.6889
5	4334.9609	3993.3367	3810.9023
6	4493.9353	4045.8989	3752.4285
7	4490.9585	4086.8028	3677.9558
8	4129.1243	3947.1350	3478.8771
9	3881.9350	3433.3001	3185.2230
10	3962.0541	3320.9029	3204.5826
11	3970.6914	3435.6337	3422.7344
12	3955.1993	3546.7085	3772.0930
13	4116.3849	3701.5299	3762.2395
14	4049.9363	3716.8200	3674.8047
15	4148.4809	3708.2776	3832.5248
16	4523.4882	3697.7386	3768.3360
17	4457.0343	3681.7711	3791.9954
18	4188.4882	3708.3153	3667.1645
19	4219.0735	3784.2520	3653.2559
20	4457.8420	3844.0420	3567.2030
21	3942.3873	3717.0251	3347.5788
22	3830.3347	3708.0957	3250.1484
23	4013.3866	3847.6551	3464.2348
24	4388.9326	4021.5655	3607.4656

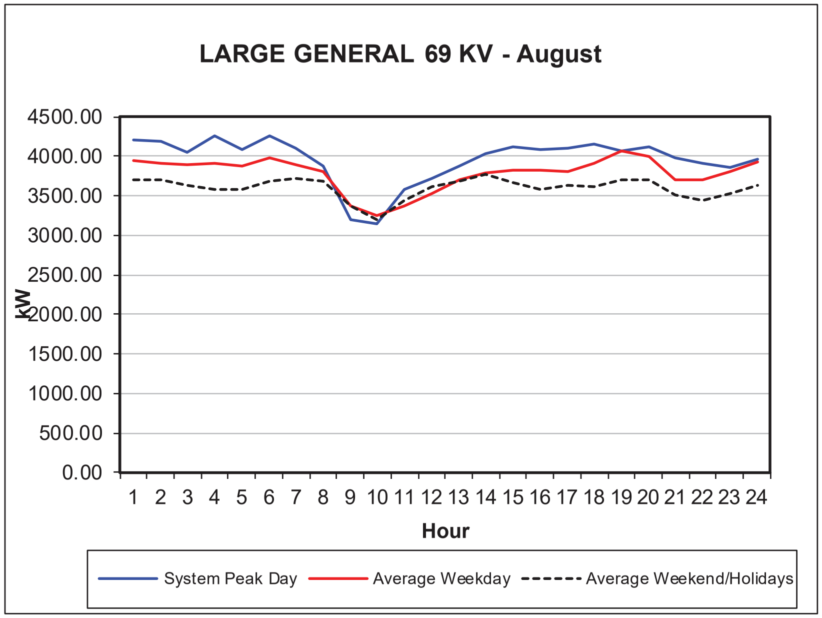


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4202.3776	3952.3476	3697.4094
2	4183.7067	3917.8645	3700.1224
3	4049.4168	3897.2949	3623.4961
4	4263.7158	3913.5517	3571.7400
5	4074.7030	3883.1855	3587.5304
6	4265.4878	3972.7083	3688.4543
7	4092.1510	3890.8723	3725.2323
8	3870.8716	3810.2182	3685.4102
9	3190.4017	3361.9510	3365.0202
10	3145.7666	3242.8565	3195.9368
11	3576.1088	3376.8006	3437.6447
12	3719.0374	3525.6250	3605.2323
13	3874.5446	3699.5985	3683.6638
14	4038.4139	3789.1041	3765.0484
15	4112.0040	3818.4363	3662.2977
16	4079.7815	3814.9846	3577.3222
17	4101.0826	3808.4639	3635.5572
18	4148.6256	3907.0150	3621.8440
19	4073.1926	4063.5847	3704.9215
20	4112.6214	3987.8820	3694.2251
21	3985.5526	3703.2882	3508.4652
22	3912.6906	3700.2847	3433.0434
23	3850.3966	3801.7414	3527.1582
24	3962.6878	3933.8730	3630.5777

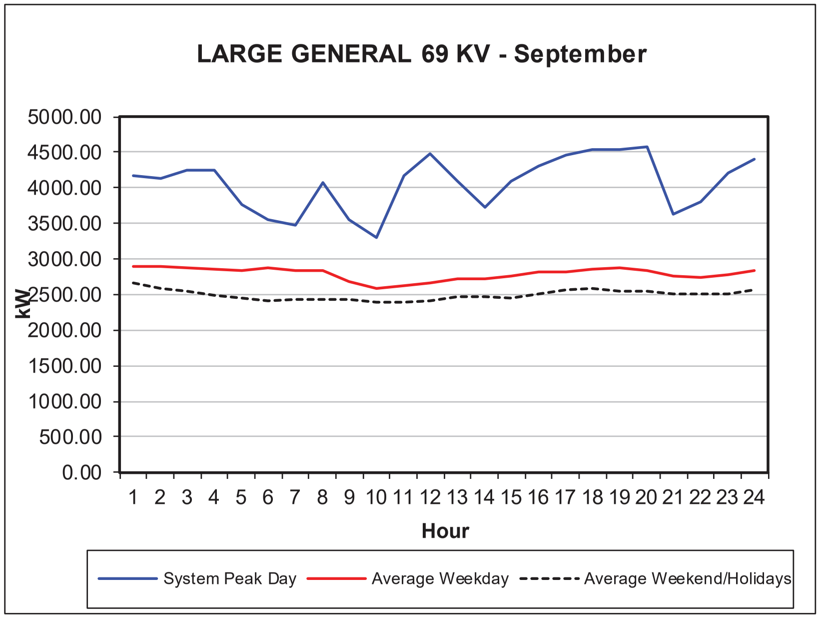


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4174.6792	2897.5625	2654.9135
2	4133.6081	2896.2561	2579.5696
3	4237.6559	2878.3690	2548.6180
4	4243.6797	2856.0286	2483.4881
5	3773.3372	2835.4210	2443.4128
6	3545.3432	2869.1877	2410.3390
7	3464.6475	2827.3105	2422.5664
8	4070.7060	2830.5250	2437.4569
9	3545.8355	2684.8209	2426.9262
10	3304.7510	2576.6841	2387.8868
11	4164.8272	2630.9060	2385.3492
12	4485.1653	2667.4902	2413.9318
13	4099.8311	2715.9099	2472.9855
14	3718.8629	2721.6694	2470.3309
15	4101.6263	2750.5304	2442.7102
16	4314.0918	2809.5881	2511.4503
17	4450.3155	2808.6089	2557.9190
18	4530.6481	2851.1438	2589.7392
19	4536.6843	2868.0575	2555.4787
20	4584.8220	2839.1727	2544.7084
21	3619.6548	2767.0192	2503.0095
22	3798.0809	2742.9839	2504.2000
23	4204.0552	2782.5874	2514.8419
24	4408.6739	2837.6056	2558.1781

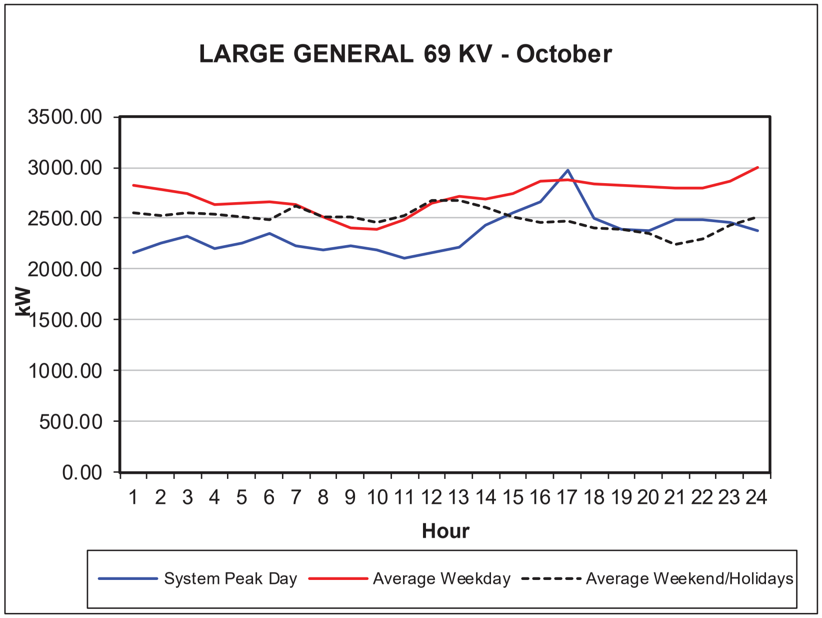


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2162.6756	2825.2905	2559.0070
2	2252.0507	2777.4960	2533.1501
3	2327.8805	2741.8348	2547.6674
4	2203.1899	2636.8551	2544.9218
5	2260.3968	2650.0710	2515.6888
6	2345.5758	2659.4010	2490.7339
7	2230.4593	2634.9091	2616.3675
8	2191.0827	2519.3387	2508.6459
9	2230.7263	2409.9255	2512.8949
10	2186.3947	2387.5390	2459.3702
11	2112.4055	2480.5032	2522.6341
12	2158.4713	2653.7559	2674.2200
13	2217.2497	2719.0505	2677.9852
14	2432.4121	2683.2300	2612.5097
15	2553.7730	2749.0943	2513.7959
16	2659.5907	2869.0563	2455.1238
17	2979.1898	2877.9352	2466.1003
18	2492.8556	2841.7367	2402.8148
19	2385.6321	2827.6537	2386.2731
20	2378.6651	2812.5651	2345.4906
21	2483.5424	2797.6077	2246.6229
22	2479.4533	2792.7092	2295.4594
23	2452.5069	2869.8807	2438.3832
24	2376.6010	2994.4251	2513.2987

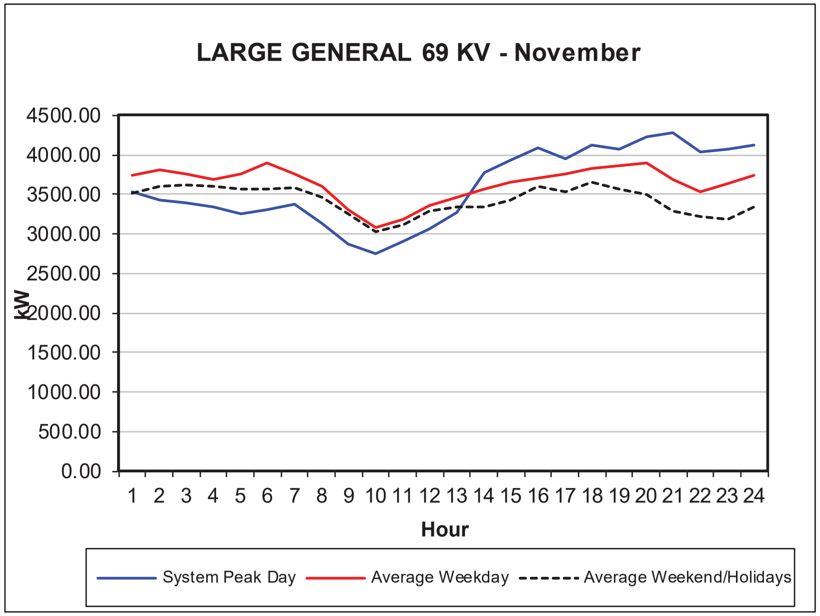


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3530.3781	3744.9534	3515.6091
2	3434.2710	3805.3185	3593.8512
3	3390.4737	3753.0986	3610.8506
4	3330.8721	3695.2398	3601.3305
5	3250.6349	3760.8846	3568.5145
6	3299.3687	3903.9531	3568.8289
7	3370.3417	3757.9151	3577.5197
8	3133.2313	3595.4376	3466.0318
9	2871.4062	3305.4737	3251.5225
10	2752.1241	3083.1539	3030.5242
11	2905.5807	3189.5859	3111.9788
12	3067.4798	3347.9818	3287.1377
13	3276.7444	3465.4394	3330.8626
14	3775.3509	3567.2220	3335.6444
15	3931.4651	3649.7839	3418.4715
16	4085.0386	3701.5134	3599.9636
17	3947.5065	3764.4322	3521.8504
18	4126.1612	3826.8721	3655.8700
19	4063.8698	3859.5842	3560.3603
20	4225.5024	3899.0962	3487.6310
21	4270.9228	3693.4637	3293.1056
22	4042.3852	3524.3092	3212.6662
23	4072.0932	3634.9495	3187.4551
24	4122.9874	3747.0088	3341.1245

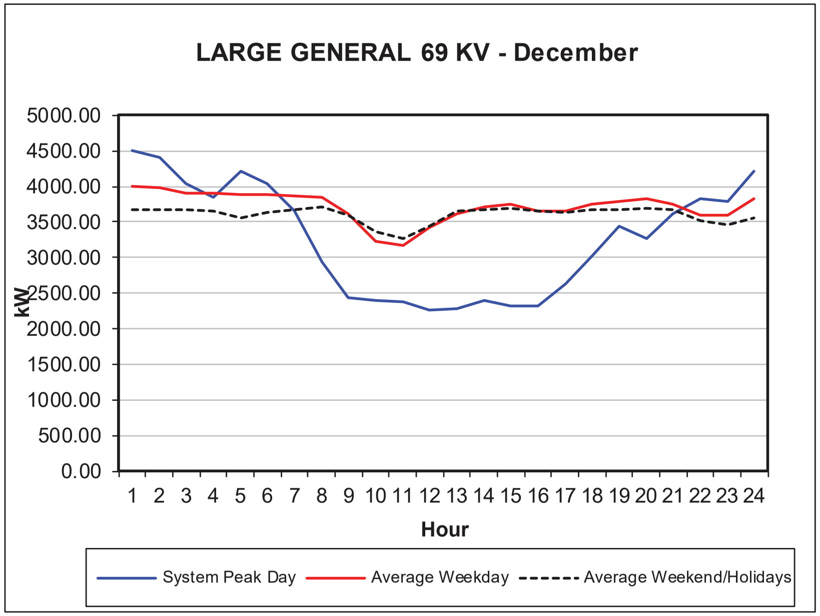


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-5.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4494.5014	4001.7270	3668.8439
2	4404.5562	3978.6223	3675.8176
3	4036.7069	3907.6541	3662.6771
4	3851.4390	3908.6113	3645.7451
5	4213.1934	3882.0348	3555.1611
6	4044.9010	3881.5747	3624.2885
7	3652.0933	3870.2783	3676.6410
8	2932.8683	3838.2973	3710.8316
9	2439.1253	3609.3310	3600.1433
10	2386.8231	3217.7761	3364.6548
11	2380.3249	3166.3762	3266.4826
12	2262.7326	3418.8237	3434.0141
13	2288.1465	3615.2350	3646.2647
14	2401.4497	3701.1634	3671.8084
15	2313.9041	3747.8151	3691.1829
16	2324.0477	3658.6472	3649.7025
17	2630.2992	3644.6553	3628.9513
18	3012.7042	3748.4310	3667.8046
19	3444.2467	3796.9878	3677.0720
20	3274.5197	3823.1444	3698.8419
21	3618.0998	3756.0657	3676.9155
22	3824.2679	3585.9976	3520.6951
23	3779.5928	3600.3405	3463.1639
24	4208.5647	3823.0733	3557.8691

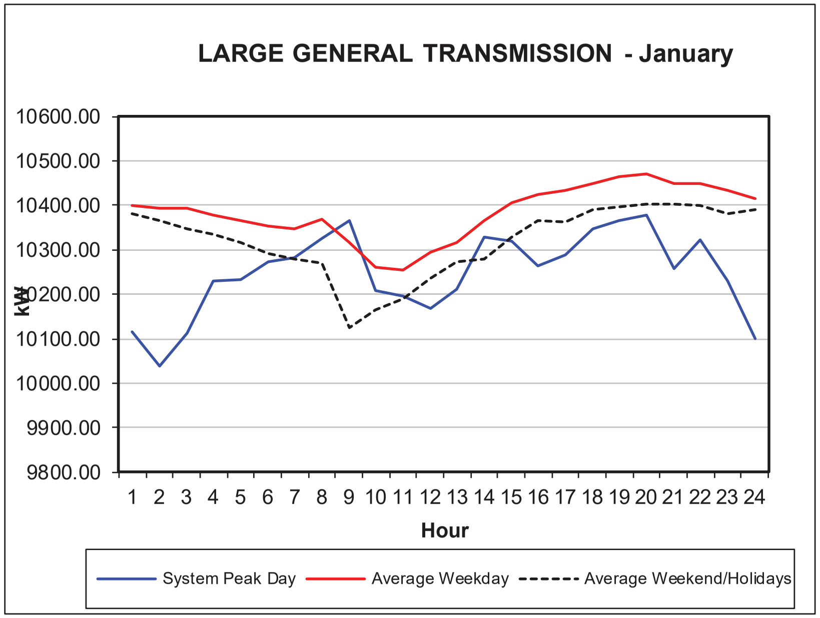


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10117.2478	10399.1842	10382.2620
2	10037.6612	10394.2111	10366.8009
3	10113.5729	10391.8752	10348.1497
4	10230.9145	10377.4997	10333.9111
5	10231.5984	10366.8600	10316.0812
6	10272.6802	10353.1088	10292.4806
7	10282.1572	10346.0625	10280.2190
8	10325.3474	10367.6711	10269.3484
9	10365.2516	10315.2814	10124.6078
10	10206.9843	10261.3898	10164.7972
11	10197.3111	10254.8733	10190.4651
12	10166.7043	10295.5450	10235.5276
13	10212.1254	10316.8555	10271.9341
14	10327.1825	10364.3595	10278.1062
15	10319.7034	10406.3807	10329.9421
16	10263.8325	10423.7203	10364.7776
17	10289.5216	10432.6919	10362.1256
18	10346.4336	10448.4115	10389.3519
19	10365.3371	10464.2798	10395.5276
20	10376.7239	10471.7916	10402.8297
21	10256.6529	10450.4099	10403.1702
22	10321.0920	10449.6158	10399.0664
23	10228.6281	10433.4180	10380.0766
24	10100.9038	10414.9091	10390.2407

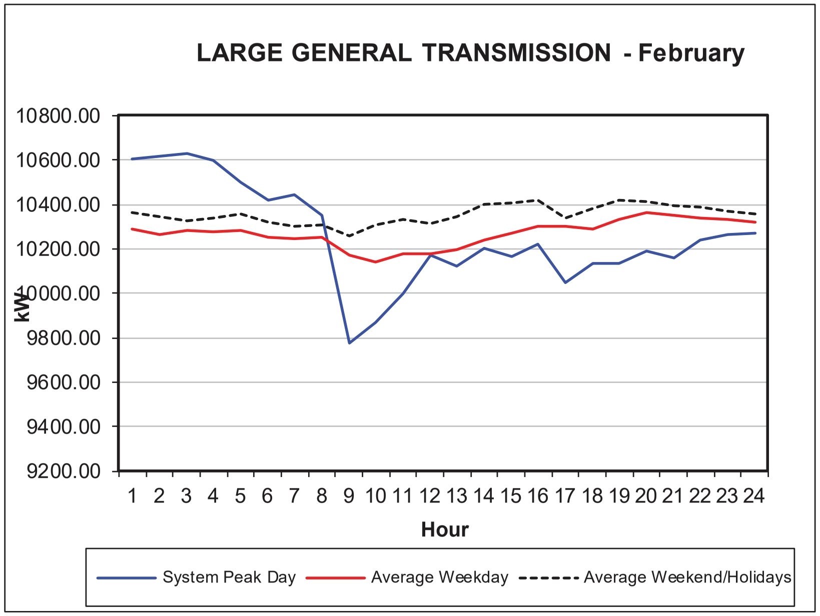


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10603.9404	10288.3339	10360.4279
2	10619.1479	10263.0835	10346.1912
3	10626.1763	10284.7005	10328.6595
4	10596.5588	10274.4060	10337.7322
5	10497.2318	10281.5195	10354.0448
6	10419.1012	10254.3507	10322.4450
7	10441.5079	10247.9151	10299.6556
8	10351.8230	10250.1013	10305.2563
9	9773.9329	10169.9902	10257.1873
10	9868.3481	10139.5036	10307.6796
11	10000.3205	10180.7396	10334.1812
12	10168.5281	10178.8215	10315.8408
13	10122.2009	10197.9650	10343.2014
14	10200.5972	10241.5694	10397.8670
15	10162.9711	10270.4513	10403.5576
16	10218.4469	10303.9947	10421.2642
17	10045.2447	10304.1412	10335.4528
18	10132.8919	10286.2116	10382.2149
19	10133.2102	10329.9625	10420.3889
20	10189.8118	10362.2867	10411.1247
21	10162.1527	10348.9385	10397.0397
22	10237.4910	10337.3024	10386.1433
23	10265.2859	10332.7795	10370.4277
24	10272.6651	10320.5990	10356.7126

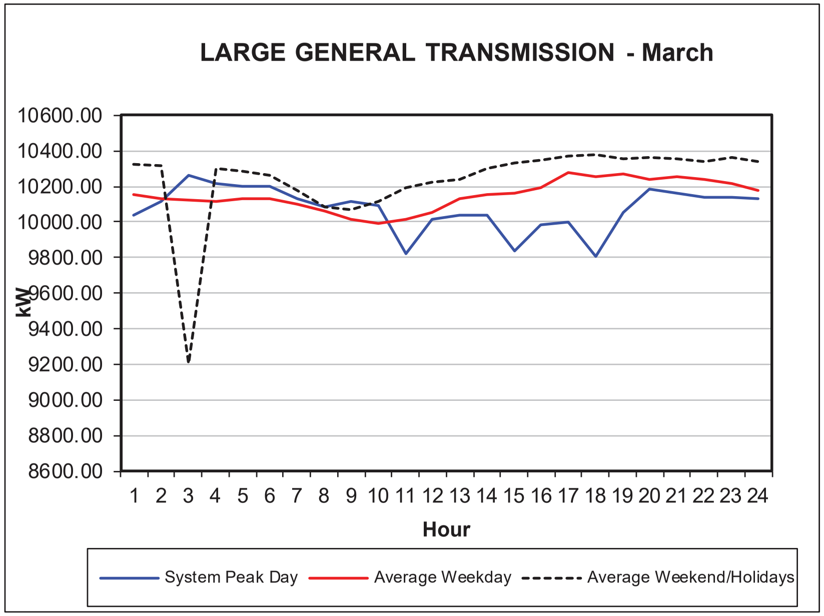


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10038.0287	10152.4054	10320.7353
2	10112.9735	10132.2410	10312.4345
3	10263.1557	10124.6447	9202.2147
4	10212.5694	10112.3803	10296.7304
5	10197.5324	10133.3300	10283.9655
6	10197.8550	10133.5598	10261.0746
7	10127.3717	10102.4295	10179.2764
8	10080.5104	10059.4670	10082.0287
9	10116.9227	10016.8421	10066.6599
10	10091.1416	9989.5628	10118.0283
11	9821.1616	10013.7185	10195.9373
12	10014.6778	10056.4845	10223.1437
13	10034.0423	10127.6641	10236.7792
14	10036.5947	10156.9210	10297.8754
15	9835.8639	10164.2117	10330.5096
16	9982.7061	10193.4052	10347.2924
17	9999.3860	10274.2675	10370.5693
18	9805.0610	10256.2960	10374.1671
19	10049.4868	10266.9847	10357.4131
20	10182.7040	10241.3550	10361.9086
21	10159.2323	10254.5156	10355.0821
22	10135.1158	10237.7653	10341.9263
23	10137.8267	10216.3531	10358.9792
24	10129.4869	10173.2945	10337.2202

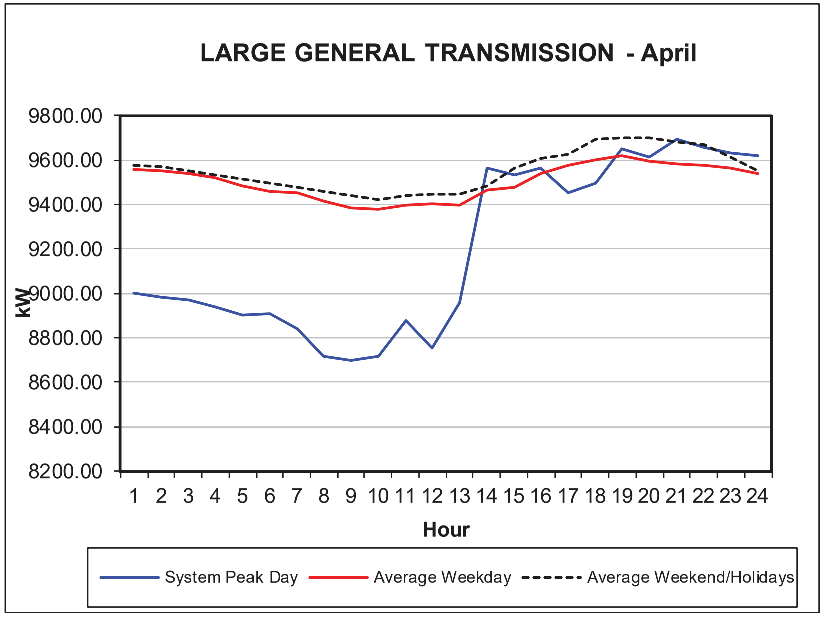


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8999.9779	9558.8366	9575.1242
2	8979.7816	9552.0966	9572.3273
3	8972.9107	9541.3208	9553.8823
4	8939.7758	9521.3569	9534.2771
5	8900.0062	9482.1498	9514.8625
6	8907.0734	9458.6471	9498.0310
7	8840.9528	9450.3240	9474.7585
8	8718.1080	9415.6316	9456.1787
9	8700.7958	9385.8358	9443.3503
10	8718.4255	9380.1843	9423.5000
11	8876.2429	9398.7075	9441.3806
12	8756.6939	9405.2845	9445.2217
13	8957.1074	9399.8236	9446.9627
14	9565.2397	9466.1861	9482.5567
15	9531.5023	9479.8672	9563.6590
16	9562.6413	9538.1985	9607.0868
17	9452.3585	9578.9991	9627.1391
18	9498.1302	9599.4998	9692.6258
19	9648.1182	9618.7238	9701.0951
20	9611.2023	9592.9800	9699.8714
21	9691.3580	9585.3051	9679.7416
22	9656.0885	9577.3910	9666.4792
23	9634.4803	9564.0939	9615.1654
24	9622.3380	9538.0565	9552.5834

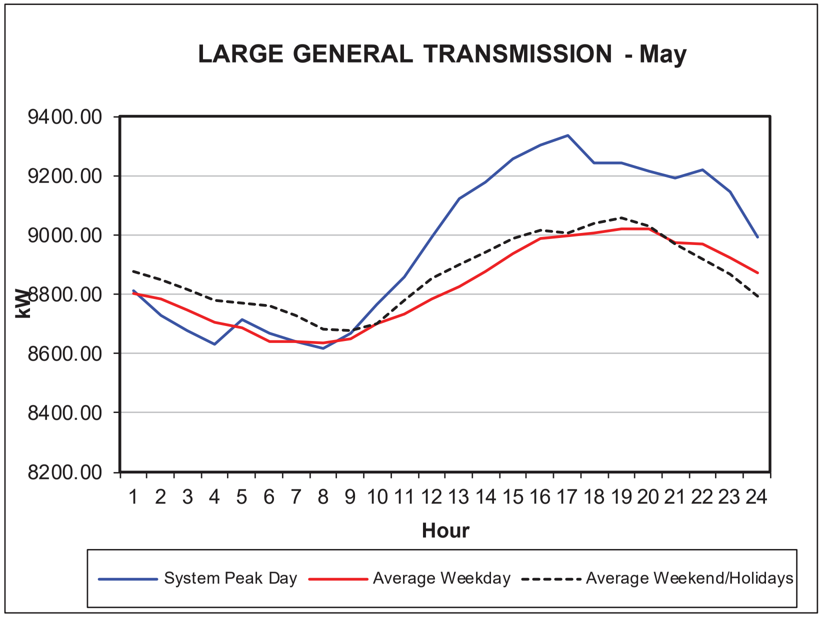


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8812.4028	8803.4382	8877.2997
2	8727.7807	8785.4373	8850.2338
3	8678.4863	8747.2704	8817.0000
4	8630.6032	8707.5838	8779.0068
5	8714.9625	8684.7058	8769.9341
6	8667.5488	8641.2482	8761.2105
7	8641.6476	8642.3277	8729.3496
8	8617.0011	8637.5369	8681.1878
9	8668.6221	8650.8056	8675.6331
10	8764.7606	8700.9850	8699.8337
11	8857.7779	8733.0946	8782.0193
12	8993.3176	8785.4342	8856.0513
13	9123.0533	8825.2863	8902.2055
14	9179.0390	8879.2500	8943.6190
15	9258.0160	8935.5861	8989.9657
16	9303.0564	8989.2024	9017.1730
17	9335.9278	8997.4393	9007.7553
18	9242.2736	9009.2190	9040.4089
19	9245.1985	9020.8353	9058.3936
20	9215.5309	9020.0646	9031.4389
21	9193.2065	8973.3105	8971.7622
22	9220.5355	8968.5541	8921.1015
23	9146.0301	8921.7183	8867.9565
24	8992.7069	8873.8912	8793.1229

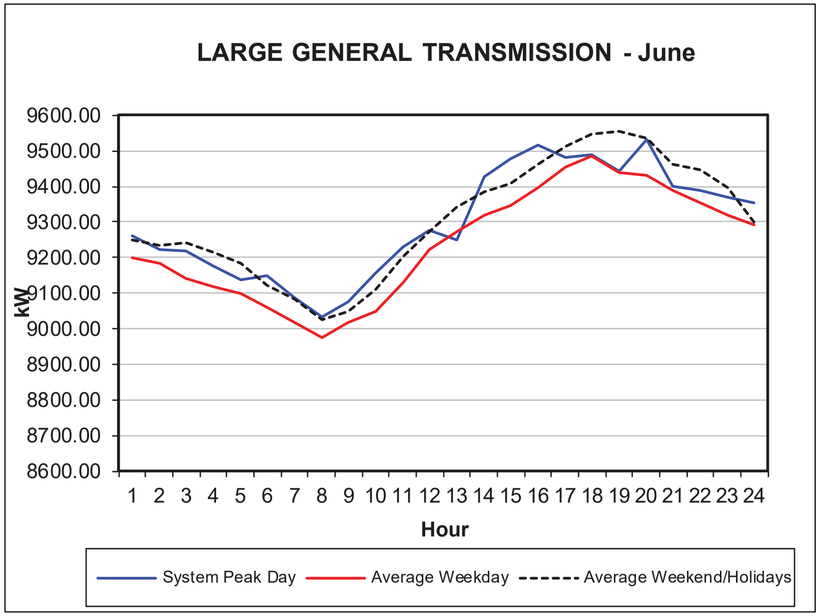


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9261.2256	9197.6801	9250.6191
2	9223.8984	9185.3138	9233.4406
3	9216.5701	9140.7496	9242.6152
4	9175.5158	9116.0980	9216.2965
5	9137.3385	9100.0864	9181.7994
6	9147.0786	9061.1201	9123.1536
7	9087.7784	9016.3075	9082.0174
8	9033.8557	8976.5241	9025.0865
9	9076.4211	9015.8149	9046.7762
10	9156.2701	9049.0520	9111.2161
11	9228.4528	9128.8085	9203.2040
12	9275.4525	9222.6351	9270.6028
13	9248.9170	9273.5893	9342.5352
14	9425.1730	9317.9730	9383.3379
15	9477.1047	9346.1252	9406.9989
16	9514.8593	9395.2835	9463.2953
17	9482.8066	9454.0113	9513.9782
18	9489.6947	9485.4310	9548.2431
19	9442.4749	9439.3043	9554.2839
20	9530.8511	9432.4312	9536.2638
21	9401.8297	9388.7244	9462.2409
22	9386.6433	9354.8565	9445.0654
23	9367.9655	9320.7543	9395.7091
24	9352.6135	9293.5028	9301.0958

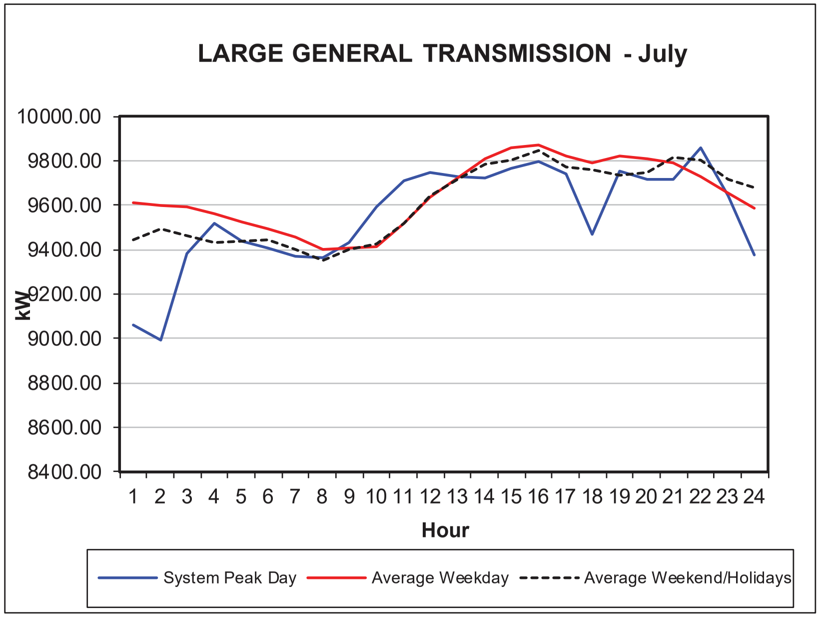


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9059.1288	9609.8361	9441.8708
2	8995.2004	9597.7634	9495.5194
3	9383.5618	9589.1029	9463.9953
4	9518.7661	9560.6689	9433.9400
5	9434.9102	9524.0406	9435.5350
6	9407.5778	9496.0382	9444.2074
7	9368.9115	9458.0017	9402.1470
8	9363.0387	9401.9815	9351.3029
9	9432.3009	9408.2884	9402.7500
10	9589.7729	9411.3978	9422.2566
11	9709.5002	9517.3041	9519.9449
12	9747.0681	9633.0006	9642.2066
13	9730.6072	9720.1065	9713.1976
14	9719.7241	9808.7349	9784.6152
15	9764.2815	9858.2935	9804.2357
16	9798.4457	9873.1641	9844.0852
17	9742.5416	9818.6930	9774.3135
18	9469.3253	9788.7161	9760.7340
19	9755.0255	9819.6973	9734.9147
20	9717.2848	9808.8889	9748.9239
21	9715.3337	9791.1902	9813.6949
22	9855.7747	9729.1327	9805.2062
23	9639.2159	9652.4974	9718.7753
24	9374.1111	9583.4273	9680.4766

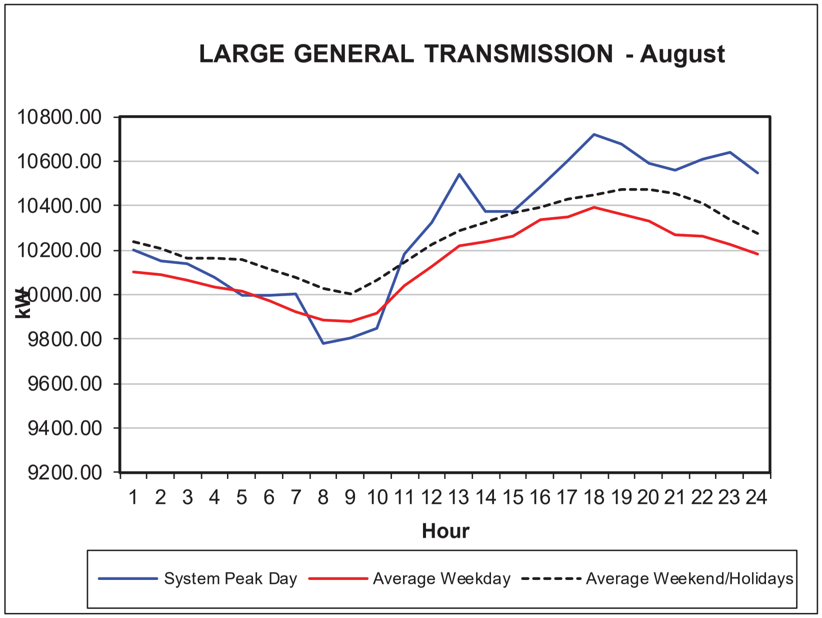


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10202.6791	10102.8975	10239.7829
2	10149.8407	10086.7839	10204.6704
3	10136.5100	10063.8099	10165.4150
4	10077.3241	10033.8687	10160.5169
5	9995.1774	10013.1752	10154.1583
6	9998.4314	9971.7930	10116.5364
7	10001.7773	9922.0573	10075.9180
8	9780.4046	9884.5018	10024.5143
9	9804.1956	9878.0525	10004.7898
10	9850.1590	9918.4898	10063.3096
11	10184.1507	10038.3856	10147.0111
12	10326.5043	10125.5097	10225.4432
13	10539.2675	10216.2009	10289.8097
14	10375.0877	10236.8039	10326.0149
15	10372.9072	10261.7956	10364.5504
16	10483.2358	10335.7326	10392.7777
17	10602.3877	10349.8365	10428.3220
18	10717.9896	10391.1926	10445.8713
19	10674.5424	10362.0488	10471.0457
20	10589.3802	10327.6667	10473.1429
21	10556.9836	10270.1884	10451.8732
22	10609.2647	10259.3707	10411.7754
23	10640.0359	10226.9054	10333.5672
24	10548.5491	10180.6438	10277.3716

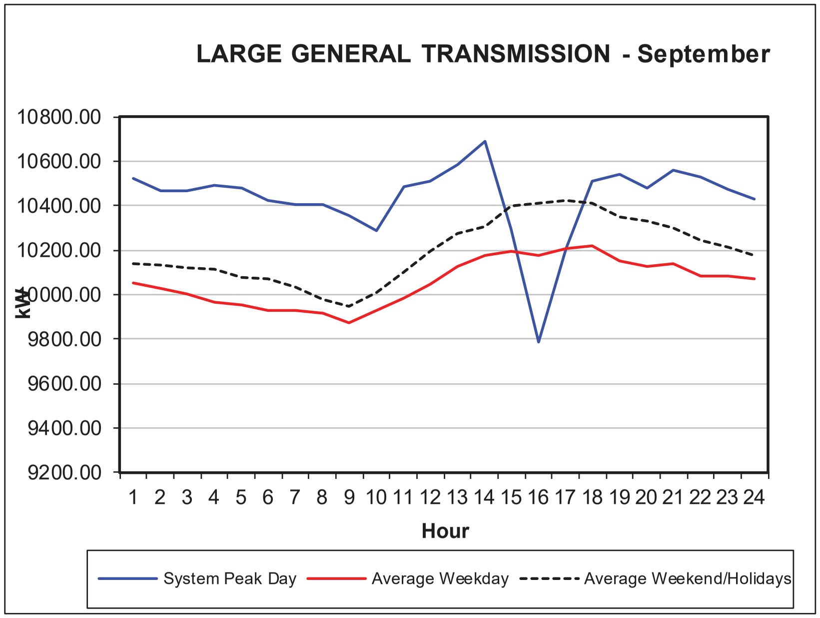


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10520.6544	10049.3424	10141.0582
2	10465.5149	10029.1374	10133.6023
3	10463.6115	9999.5787	10122.3499
4	10488.5144	9963.6363	10113.1932
5	10475.8958	9951.5945	10075.2854
6	10420.8077	9926.3959	10069.6082
7	10406.7476	9926.3370	10035.6896
8	10405.3633	9917.1811	9974.8479
9	10356.5606	9871.5008	9944.6048
10	10284.8878	9928.2462	10011.3802
11	10486.8081	9983.1485	10104.4951
12	10506.9382	10046.5367	10192.6039
13	10583.9438	10124.9617	10273.6375
14	10687.3047	10175.4928	10308.0778
15	10292.4400	10191.5937	10399.1110
16	9785.7808	10175.7820	10410.2677
17	10206.6991	10209.3256	10422.7547
18	10510.9806	10218.1701	10408.1638
19	10538.8186	10149.5170	10351.3642
20	10479.1913	10128.9093	10327.4104
21	10557.6205	10141.0374	10296.9104
22	10527.2217	10081.2849	10246.3234
23	10474.5752	10081.7511	10211.8924
24	10426.9352	10070.1419	10172.8376

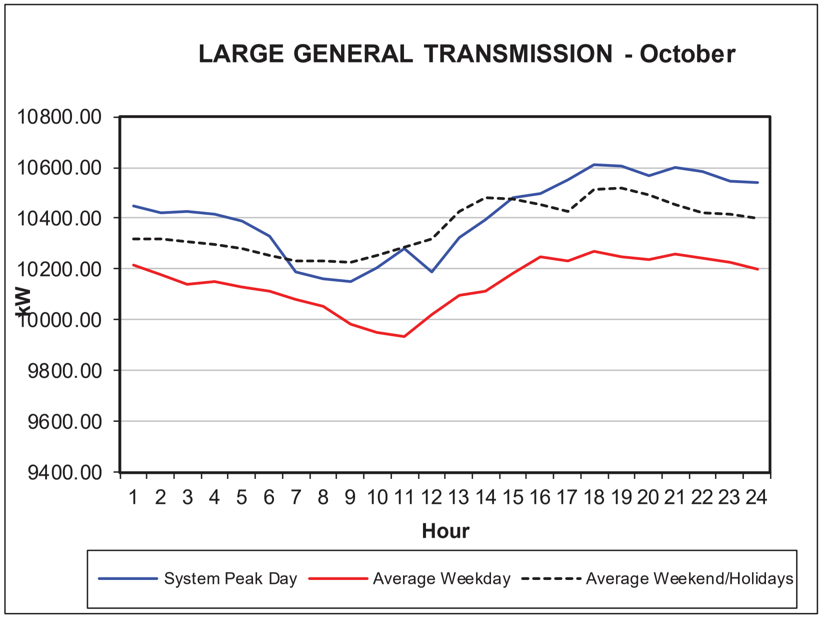


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10445.9014	10213.9891	10316.7592
2	10423.0300	10180.3216	10317.4603
3	10425.2321	10141.7718	10306.6839
4	10417.0019	10148.5799	10297.4779
5	10390.4204	10130.4297	10281.0784
6	10327.1487	10112.3961	10251.1727
7	10189.3582	10079.1096	10231.7346
8	10161.4585	10053.3653	10231.3621
9	10153.3723	9983.7483	10225.2880
10	10206.9452	9949.2457	10253.2588
11	10278.6544	9936.8237	10285.6413
12	10188.2537	10019.4629	10317.4488
13	10326.0372	10094.1729	10429.2645
14	10393.1767	10115.1807	10479.6279
15	10481.4347	10180.8246	10475.3765
16	10494.6907	10246.9887	10452.2559
17	10553.1210	10232.6893	10428.9581
18	10610.7869	10268.0759	10514.0481
19	10606.5872	10249.2884	10521.0230
20	10568.9608	10234.9926	10491.2653
21	10600.0917	10261.8104	10456.5756
22	10583.0572	10242.0140	10419.2444
23	10548.0955	10226.7590	10418.6219
24	10538.4369	10202.2466	10399.5820

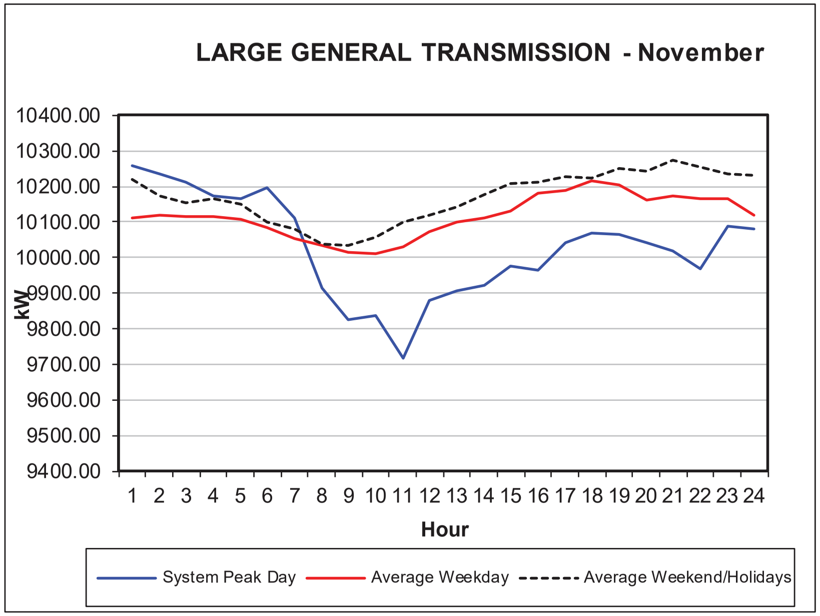


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10259.3272	10111.2759	10219.5857
2	10234.8862	10118.3194	10173.2663
3	10210.0370	10115.6604	10152.2856
4	10173.7152	10113.2839	10163.5627
5	10166.0612	10108.2377	10150.4952
6	10194.7501	10083.6688	10099.6936
7	10109.3071	10051.2751	10081.6036
8	9913.5162	10034.1676	10037.5619
9	9824.8526	10014.9814	10031.9953
10	9835.7950	10009.8800	10056.0311
11	9717.6180	10030.1228	10098.7776
12	9879.5572	10071.0331	10117.9706
13	9905.4711	10099.2010	10140.1594
14	9923.5583	10111.4311	10177.0573
15	9975.1980	10130.7818	10207.5490
16	9966.1059	10179.2412	10212.9586
17	10042.5213	10188.7123	10228.2407
18	10069.9412	10214.6619	10221.4667
19	10066.0313	10202.1585	10249.9705
20	10040.0823	10163.2460	10241.7308
21	10016.6646	10173.5312	10271.8078
22	9966.8230	10166.9547	10253.9232
23	10089.6155	10164.3624	10234.1641
24	10078.5098	10119.7026	10229.0548

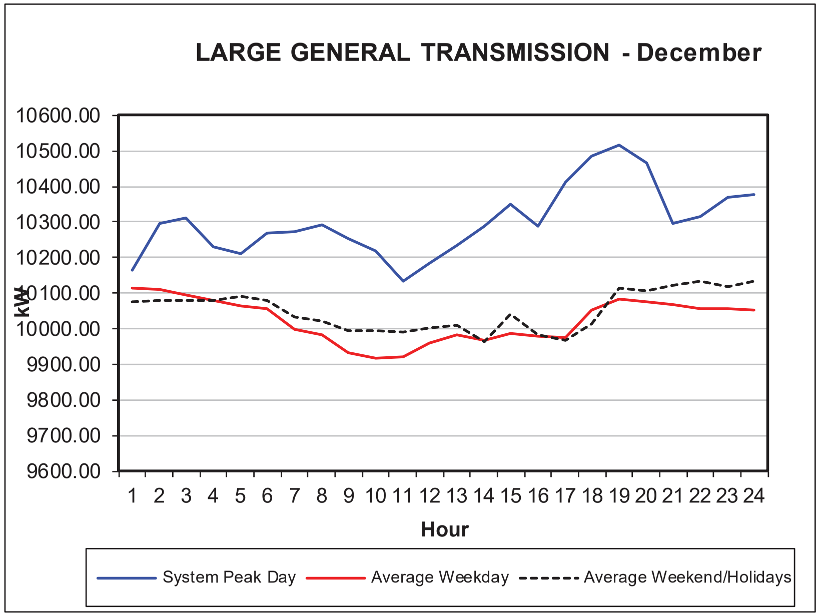


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-6.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10164.8453	10114.1107	10076.1108
2	10297.1787	10108.4940	10080.7311
3	10311.6898	10092.9276	10077.8461
4	10230.5799	10078.5324	10078.0654
5	10210.7292	10065.6357	10090.0566
6	10267.0000	10055.4348	10079.2765
7	10273.8239	9999.1328	10031.3012
8	10292.0866	9983.2951	10020.6163
9	10252.0671	9933.2068	9995.2923
10	10216.4861	9915.1743	9992.3854
11	10133.0947	9922.4530	9988.7134
12	10183.0467	9959.5216	10002.9190
13	10233.8013	9982.4290	10009.1149
14	10287.9736	9965.2660	9964.7470
15	10349.7702	9985.6774	10039.5804
16	10288.1157	9979.9157	9983.8261
17	10411.9392	9976.0557	9967.8876
18	10486.5920	10052.4815	10013.5613
19	10517.4854	10083.5195	10112.4758
20	10465.0221	10075.1164	10108.0695
21	10297.5155	10069.3366	10119.8654
22	10313.8970	10057.5784	10134.7409
23	10368.9395	10054.3876	10117.6422
24	10378.0140	10051.0748	10133.1743

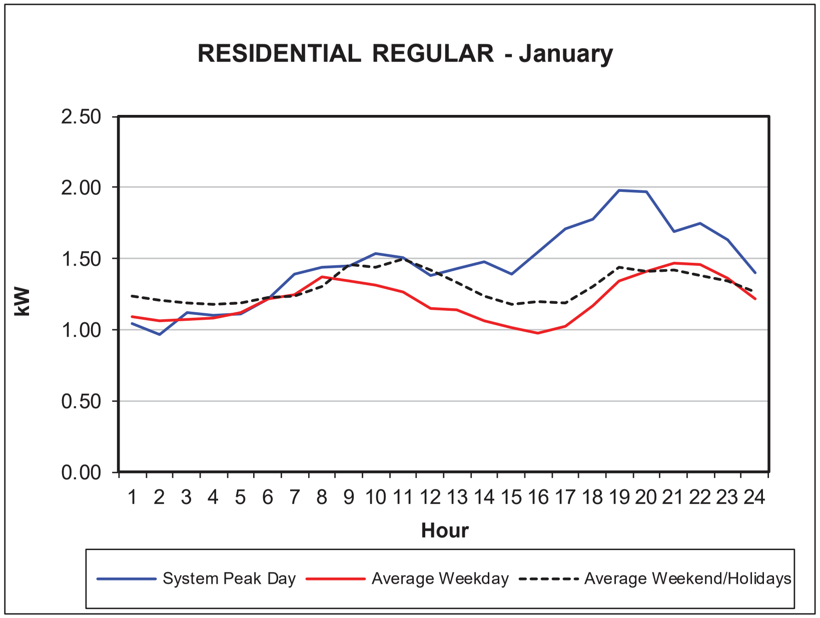


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0473	1.0946	1.2418
2	0.9627	1.0679	1.2064
3	1.1178	1.0732	1.1844
4	1.1037	1.0844	1.1785
5	1.1108	1.1263	1.1933
6	1.2186	1.2194	1.2234
7	1.3939	1.2496	1.2340
8	1.4359	1.3756	1.3082
9	1.4469	1.3414	1.4556
10	1.5383	1.3111	1.4359
11	1.5089	1.2652	1.4996
12	1.3780	1.1492	1.4222
13	1.4287	1.1446	1.3330
14	1.4760	1.0618	1.2337
15	1.3882	1.0163	1.1840
16	1.5432	0.9730	1.2006
17	1.7071	1.0298	1.1878
18	1.7790	1.1694	1.3052
19	1.9796	1.3421	1.4354
20	1.9693	1.4127	1.4104
21	1.6913	1.4702	1.4180
22	1.7511	1.4559	1.3811
23	1.6303	1.3597	1.3401
24	1.4006	1.2139	1.2658

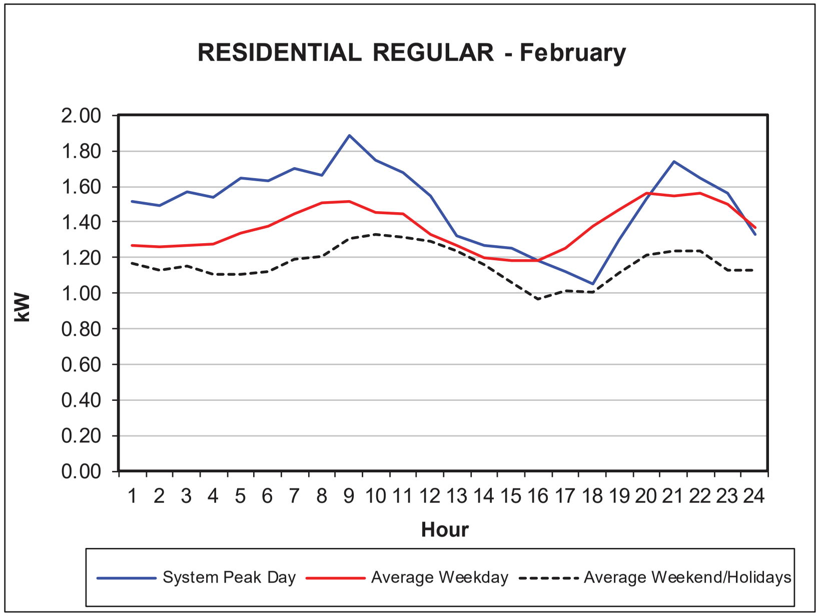


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.5155	1.2715	1.1695
2	1.4959	1.2602	1.1259
3	1.5732	1.2702	1.1501
4	1.5390	1.2735	1.1094
5	1.6439	1.3346	1.1101
6	1.6320	1.3775	1.1225
7	1.6988	1.4456	1.1883
8	1.6662	1.5073	1.2087
9	1.8881	1.5145	1.3102
10	1.7460	1.4575	1.3311
11	1.6807	1.4451	1.3187
12	1.5454	1.3338	1.2920
13	1.3236	1.2650	1.2379
14	1.2698	1.1991	1.1639
15	1.2518	1.1871	1.0586
16	1.1863	1.1858	0.9652
17	1.1233	1.2566	1.0101
18	1.0559	1.3737	1.0095
19	1.2968	1.4689	1.1137
20	1.5320	1.5597	1.2183
21	1.7417	1.5498	1.2381
22	1.6441	1.5611	1.2378
23	1.5602	1.4969	1.1256
24	1.3324	1.3705	1.1293

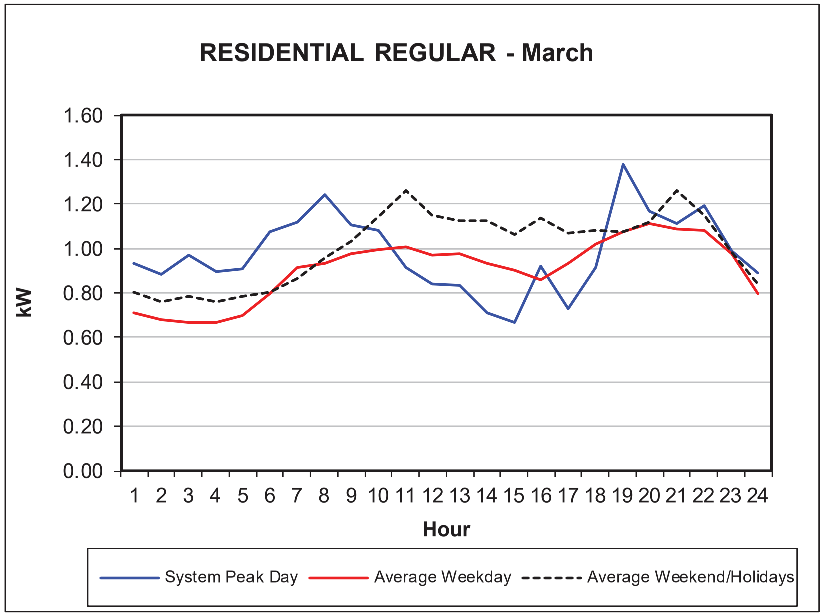


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9342	0.7107	0.8063
2	0.8856	0.6802	0.7580
3	0.9681	0.6650	0.7824
4	0.8950	0.6655	0.7605
5	0.9079	0.6972	0.7846
6	1.0767	0.7998	0.8013
7	1.1206	0.9164	0.8684
8	1.2404	0.9359	0.9581
9	1.1056	0.9763	1.0325
10	1.0824	0.9957	1.1427
11	0.9166	1.0089	1.2586
12	0.8398	0.9731	1.1505
13	0.8351	0.9766	1.1254
14	0.7092	0.9362	1.1231
15	0.6679	0.9024	1.0608
16	0.9190	0.8604	1.1370
17	0.7276	0.9355	1.0675
18	0.9167	1.0195	1.0845
19	1.3761	1.0781	1.0738
20	1.1676	1.1116	1.1180
21	1.1155	1.0902	1.2628
22	1.1957	1.0806	1.1483
23	0.9871	0.9788	0.9857
24	0.8876	0.7989	0.8394

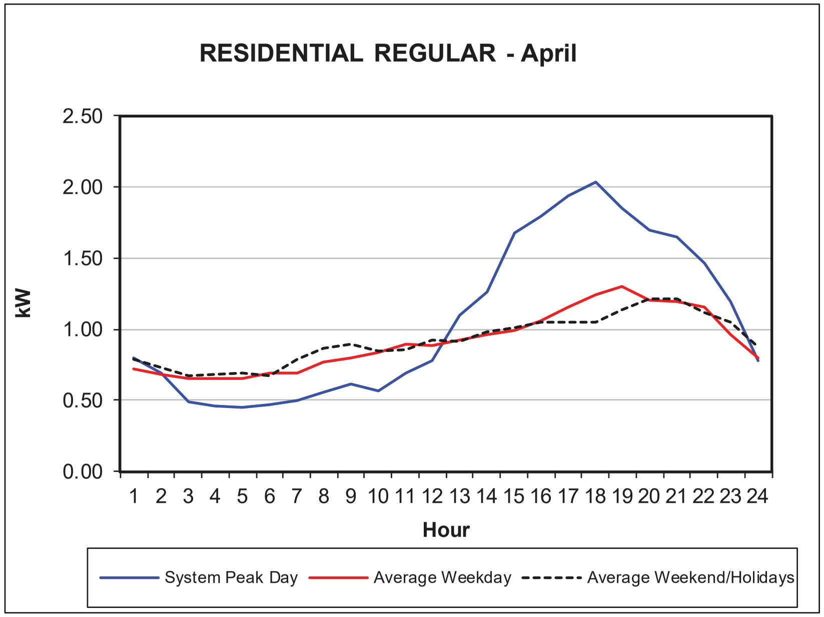


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7975	0.7186	0.7845
2	0.6893	0.6837	0.7309
3	0.4922	0.6527	0.6727
4	0.4625	0.6527	0.6843
5	0.4455	0.6516	0.6902
6	0.4739	0.6956	0.6724
7	0.5010	0.6933	0.7896
8	0.5522	0.7685	0.8659
9	0.6156	0.7980	0.8992
10	0.5644	0.8412	0.8487
11	0.6887	0.8899	0.8580
12	0.7767	0.8811	0.9229
13	1.1018	0.9226	0.9134
14	1.2605	0.9629	0.9834
15	1.6758	0.9936	1.0108
16	1.7893	1.0587	1.0489
17	1.9394	1.1540	1.0521
18	2.0313	1.2432	1.0463
19	1.8560	1.2960	1.1317
20	1.7013	1.2045	1.2160
21	1.6460	1.1900	1.2159
22	1.4631	1.1579	1.1192
23	1.1966	0.9575	1.0504
24	0.7775	0.7944	0.8781

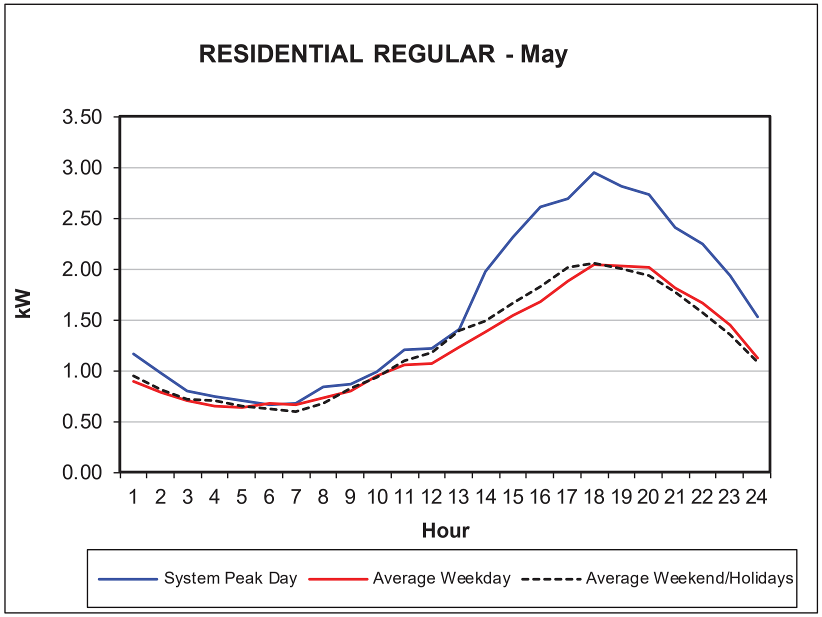


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1570	0.8862	0.9514
2	0.9745	0.7903	0.8139
3	0.8013	0.7050	0.7192
4	0.7381	0.6451	0.7057
5	0.7025	0.6306	0.6516
6	0.6690	0.6769	0.6263
7	0.6758	0.6573	0.5990
8	0.8337	0.7272	0.6830
9	0.8608	0.8041	0.8269
10	0.9860	0.9487	0.9394
11	1.2042	1.0518	1.0954
12	1.2209	1.0647	1.1832
13	1.4058	1.2304	1.3866
14	1.9702	1.3767	1.4942
15	2.3146	1.5399	1.6632
16	2.6107	1.6769	1.8299
17	2.6923	1.8791	2.0170
18	2.9497	2.0421	2.0536
19	2.8190	2.0347	2.0080
20	2.7291	2.0129	1.9344
21	2.4073	1.8058	1.7781
22	2.2440	1.6616	1.5738
23	1.9385	1.4443	1.3592
24	1.5240	1.1290	1.0867

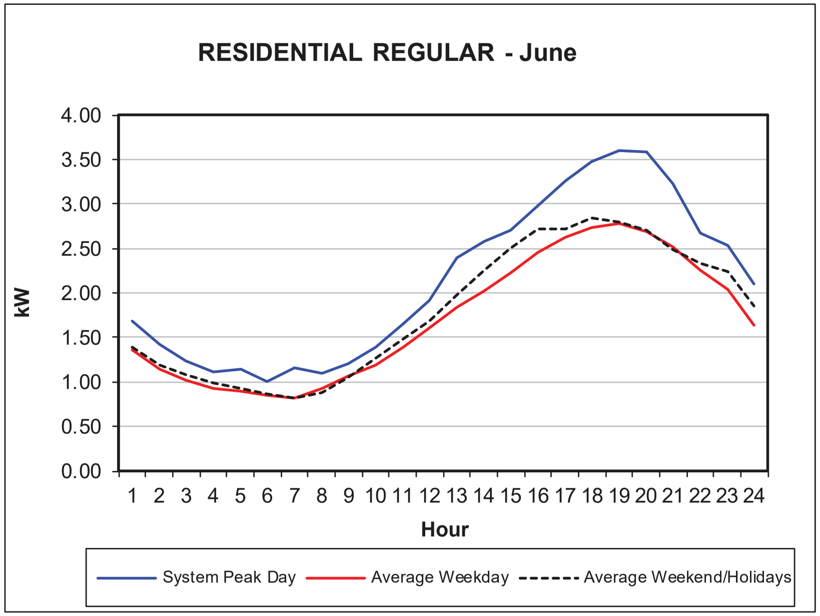


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.6900	1.3569	1.3883
2	1.4188	1.1481	1.1885
3	1.2348	1.0177	1.0869
4	1.1118	0.9325	0.9853
5	1.1369	0.8956	0.9298
6	1.0123	0.8577	0.8638
7	1.1562	0.8243	0.8206
8	1.1006	0.9285	0.8799
9	1.2081	1.0613	1.0575
10	1.3885	1.1930	1.2686
11	1.6578	1.3910	1.4879
12	1.9105	1.6096	1.6833
13	2.3917	1.8381	1.9766
14	2.5799	2.0194	2.2596
15	2.7027	2.2280	2.5038
16	2.9833	2.4604	2.7165
17	3.2626	2.6206	2.7233
18	3.4743	2.7351	2.8382
19	3.6025	2.7771	2.7934
20	3.5790	2.6859	2.6993
21	3.2246	2.5139	2.4876
22	2.6802	2.2634	2.3278
23	2.5307	2.0381	2.2419
24	2.1052	1.6378	1.8480

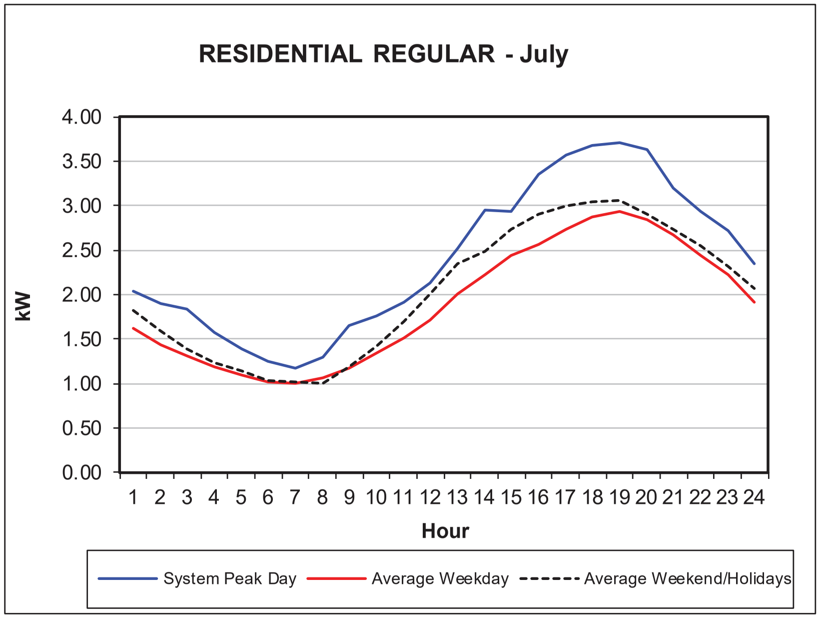


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.0404	1.6251	1.8262
2	1.9007	1.4272	1.5871
3	1.8407	1.3079	1.3954
4	1.5668	1.1901	1.2389
5	1.3828	1.0974	1.1351
6	1.2412	1.0233	1.0377
7	1.1721	0.9942	1.0207
8	1.2896	1.0637	1.0058
9	1.6479	1.1646	1.1822
10	1.7595	1.3490	1.4193
11	1.9091	1.5184	1.6975
12	2.1229	1.7190	2.0042
13	2.5238	2.0100	2.3442
14	2.9516	2.2198	2.4915
15	2.9353	2.4335	2.7305
16	3.3483	2.5664	2.9078
17	3.5743	2.7330	2.9916
18	3.6713	2.8664	3.0397
19	3.7025	2.9319	3.0595
20	3.6335	2.8482	2.9078
21	3.2011	2.6669	2.7295
22	2.9410	2.4353	2.5429
23	2.7102	2.2193	2.3121
24	2.3488	1.9071	2.0608

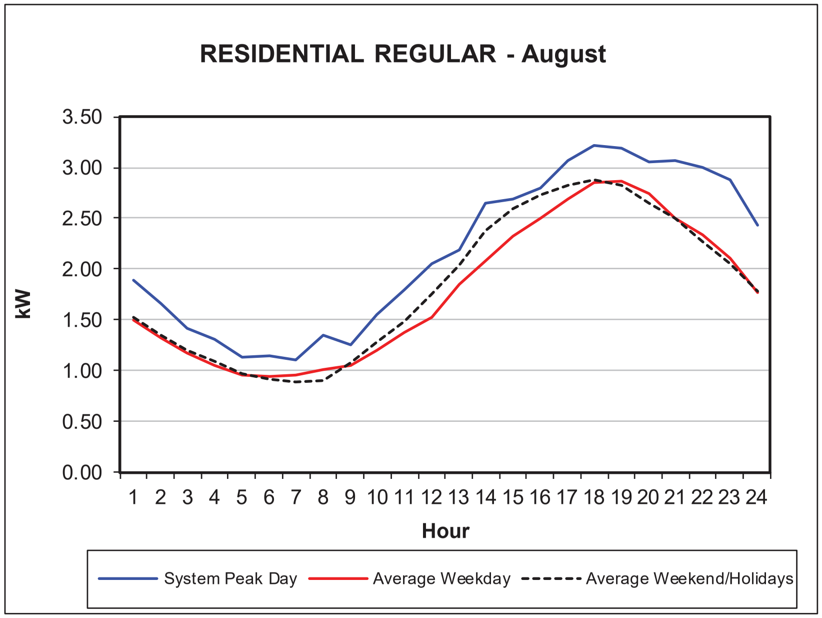


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.8935	1.5053	1.5271
2	1.6665	1.3244	1.3472
3	1.4160	1.1674	1.2070
4	1.3099	1.0554	1.0930
5	1.1358	0.9568	0.9748
6	1.1418	0.9389	0.9194
7	1.1080	0.9515	0.8960
8	1.3530	1.0085	0.8987
9	1.2535	1.0523	1.0743
10	1.5485	1.2047	1.2817
11	1.7909	1.3803	1.4842
12	2.0486	1.5263	1.7550
13	2.1821	1.8518	2.0405
14	2.6527	2.0800	2.3781
15	2.6915	2.3174	2.6000
16	2.8007	2.5049	2.7245
17	3.0688	2.6927	2.8259
18	3.2177	2.8471	2.8731
19	3.1929	2.8631	2.8291
20	3.0485	2.7458	2.6489
21	3.0661	2.4969	2.4940
22	2.9986	2.3331	2.2753
23	2.8727	2.1045	2.0551
24	2.4252	1.7749	1.7817

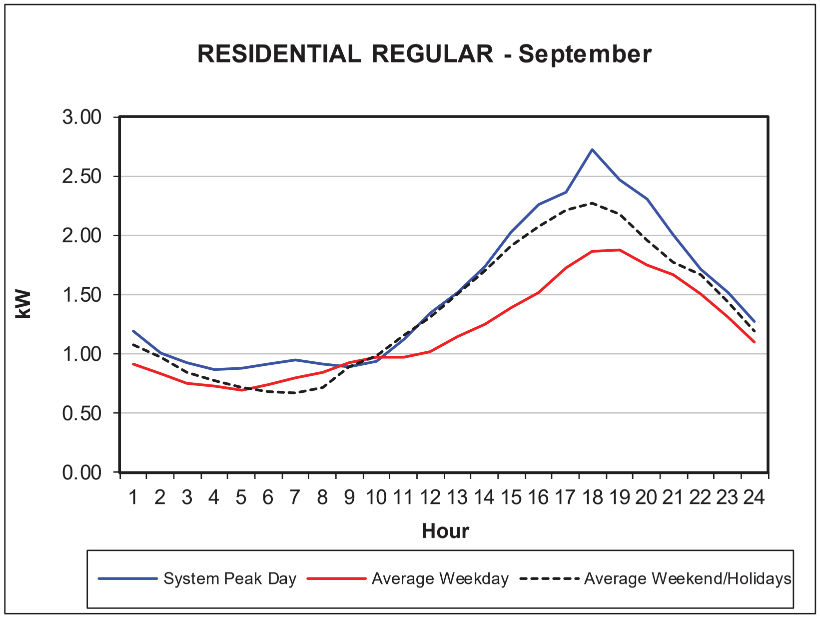


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1901	0.9100	1.0725
2	1.0014	0.8366	0.9766
3	0.9218	0.7504	0.8482
4	0.8649	0.7262	0.7726
5	0.8731	0.6888	0.7165
6	0.9078	0.7413	0.6794
7	0.9459	0.7984	0.6672
8	0.9151	0.8458	0.7109
9	0.8909	0.9225	0.8944
10	0.9412	0.9730	0.9849
11	1.1215	0.9694	1.1575
12	1.3392	1.0174	1.3125
13	1.5180	1.1460	1.5062
14	1.7384	1.2526	1.7052
15	2.0285	1.3902	1.9108
16	2.2581	1.5177	2.0759
17	2.3589	1.7298	2.2070
18	2.7254	1.8641	2.2742
19	2.4707	1.8767	2.1810
20	2.3047	1.7502	1.9591
21	1.9987	1.6644	1.7768
22	1.7115	1.5072	1.6619
23	1.5175	1.3119	1.4364
24	1.2767	1.0946	1.1926

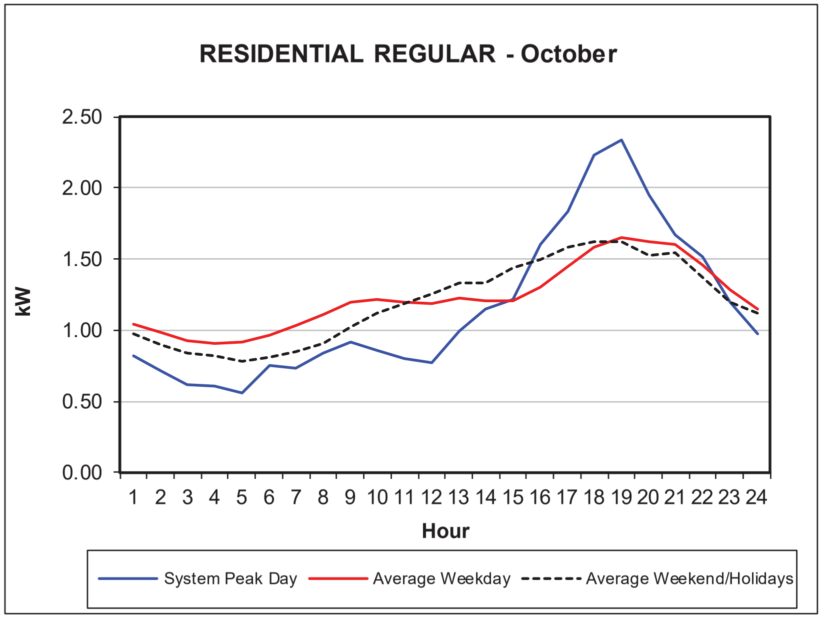


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8149	1.0427	0.9723
2	0.7086	0.9794	0.8955
3	0.6121	0.9209	0.8429
4	0.6076	0.9067	0.8165
5	0.5589	0.9144	0.7766
6	0.7506	0.9645	0.8101
7	0.7279	1.0313	0.8448
8	0.8367	1.1111	0.9109
9	0.9112	1.1954	1.0265
10	0.8614	1.2175	1.1207
11	0.7952	1.1924	1.1904
12	0.7671	1.1870	1.2572
13	0.9956	1.2275	1.3292
14	1.1432	1.2070	1.3286
15	1.2105	1.2052	1.4399
16	1.5983	1.2997	1.4955
17	1.8354	1.4425	1.5867
18	2.2279	1.5804	1.6210
19	2.3399	1.6498	1.6165
20	1.9543	1.6252	1.5202
21	1.6741	1.6047	1.5438
22	1.5142	1.4611	1.3653
23	1.1949	1.2843	1.1929
24	0.9779	1.1463	1.1190

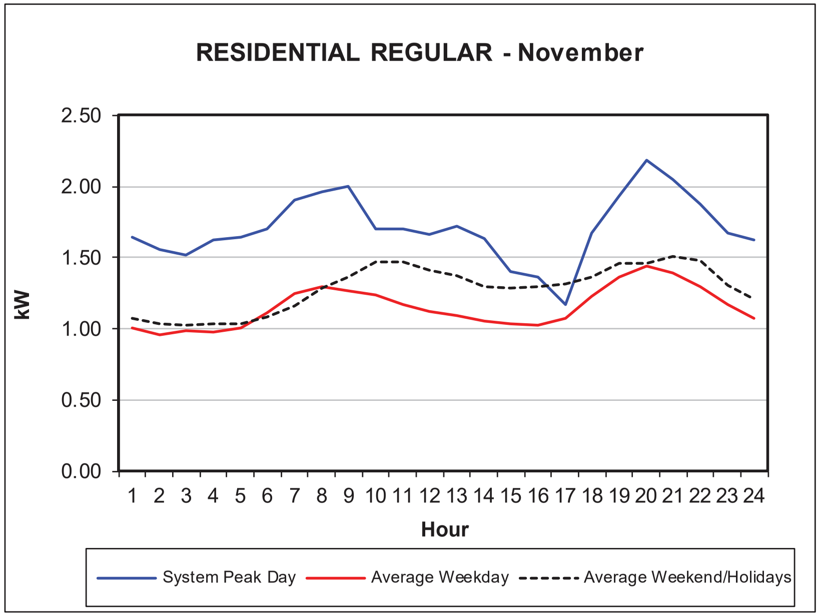


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.6404	1.0043	1.0714
2	1.5545	0.9556	1.0313
3	1.5133	0.9811	1.0233
4	1.6201	0.9737	1.0294
5	1.6466	1.0078	1.0378
6	1.7023	1.1152	1.0804
7	1.8989	1.2442	1.1631
8	1.9595	1.2905	1.2819
9	2.0005	1.2696	1.3669
10	1.7027	1.2384	1.4715
11	1.6972	1.1679	1.4641
12	1.6585	1.1228	1.4140
13	1.7170	1.0951	1.3760
14	1.6311	1.0533	1.2956
15	1.3983	1.0331	1.2897
16	1.3618	1.0271	1.2923
17	1.1705	1.0737	1.3104
18	1.6737	1.2252	1.3667
19	1.9294	1.3626	1.4550
20	2.1860	1.4418	1.4569
21	2.0519	1.3958	1.5071
22	1.8767	1.2918	1.4771
23	1.6753	1.1688	1.3083
24	1.6246	1.0687	1.2125

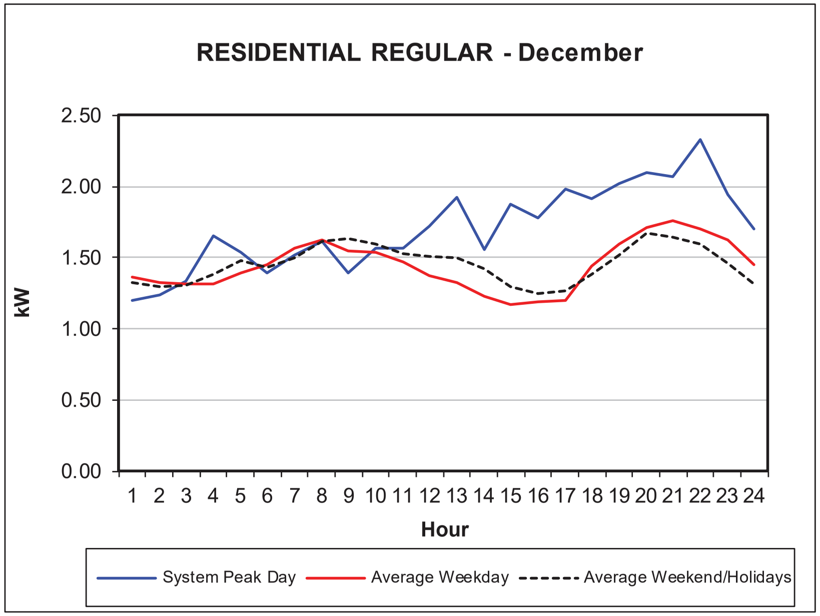


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-7.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1961	1.3585	1.3243
2	1.2335	1.3255	1.2985
3	1.3323	1.3184	1.3031
4	1.6542	1.3167	1.3852
5	1.5343	1.3934	1.4805
6	1.3875	1.4480	1.4338
7	1.5151	1.5615	1.4946
8	1.6108	1.6248	1.6146
9	1.3914	1.5507	1.6358
10	1.5610	1.5332	1.5936
11	1.5650	1.4708	1.5281
12	1.7186	1.3708	1.5085
13	1.9250	1.3226	1.4974
14	1.5565	1.2271	1.4162
15	1.8733	1.1701	1.2915
16	1.7754	1.1924	1.2464
17	1.9785	1.1984	1.2630
18	1.9159	1.4363	1.3829
19	2.0232	1.5948	1.5125
20	2.0953	1.7073	1.6730
21	2.0721	1.7566	1.6442
22	2.3325	1.6989	1.5963
23	1.9433	1.6229	1.4612
24	1.6972	1.4457	1.3165

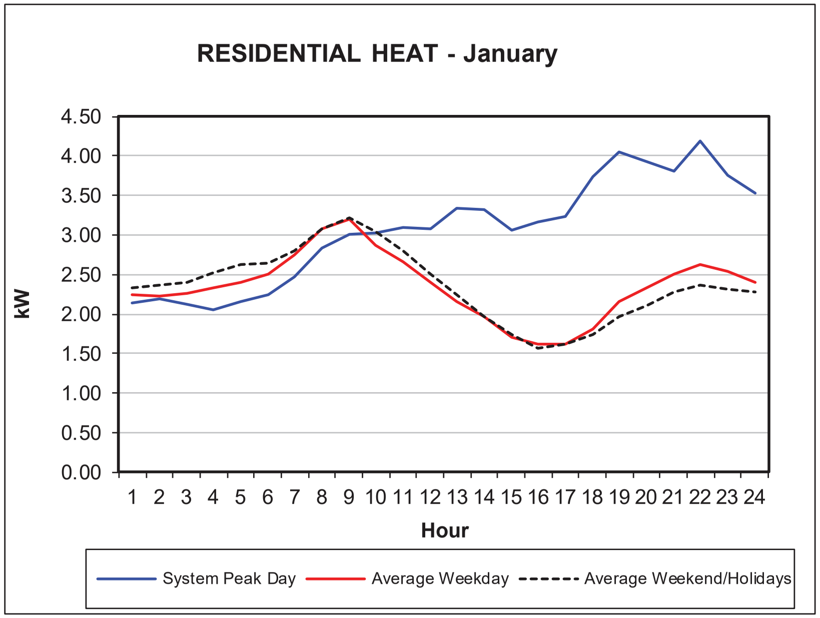


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.1362	2.2429	2.3306
2	2.2006	2.2315	2.3596
3	2.1233	2.2676	2.4024
4	2.0500	2.3377	2.5216
5	2.1556	2.3965	2.6217
6	2.2386	2.5034	2.6397
7	2.4618	2.7454	2.8073
8	2.8297	3.0842	3.0754
9	3.0014	3.2011	3.2093
10	3.0226	2.8749	3.0492
11	3.0976	2.6685	2.7970
12	3.0780	2.3929	2.5038
13	3.3322	2.1579	2.2474
14	3.3208	1.9614	1.9693
15	3.0604	1.6980	1.7490
16	3.1647	1.6125	1.5735
17	3.2408	1.6279	1.6212
18	3.7336	1.8187	1.7481
19	4.0497	2.1562	1.9644
20	3.9241	2.3392	2.1134
21	3.8015	2.4980	2.2774
22	4.1948	2.6191	2.3698
23	3.7573	2.5471	2.3173
24	3.5368	2.3925	2.2725

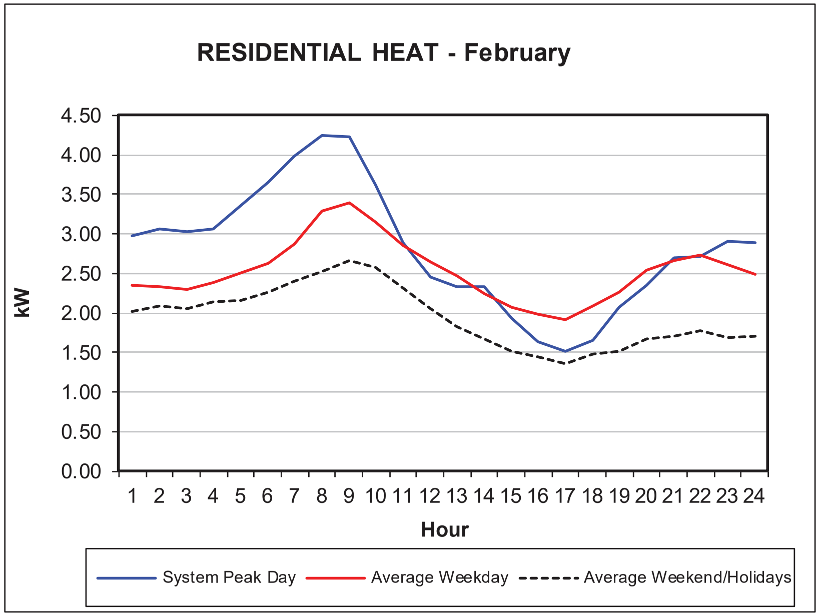


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.9748	2.3415	2.0225
2	3.0645	2.3296	2.0844
3	3.0298	2.3053	2.0552
4	3.0544	2.3786	2.1327
5	3.3586	2.5037	2.1563
6	3.6516	2.6304	2.2559
7	3.9794	2.8779	2.4090
8	4.2519	3.2878	2.5211
9	4.2233	3.3982	2.6593
10	3.6238	3.1458	2.5792
11	2.8951	2.8537	2.3230
12	2.4522	2.6499	2.0616
13	2.3356	2.4700	1.8203
14	2.3256	2.2370	1.6662
15	1.9396	2.0649	1.5218
16	1.6411	1.9777	1.4428
17	1.5216	1.9228	1.3645
18	1.6557	2.0871	1.4856
19	2.0663	2.2684	1.5231
20	2.3498	2.5414	1.6766
21	2.7011	2.6574	1.7086
22	2.7137	2.7309	1.7691
23	2.8987	2.6023	1.6936
24	2.8971	2.4939	1.7048

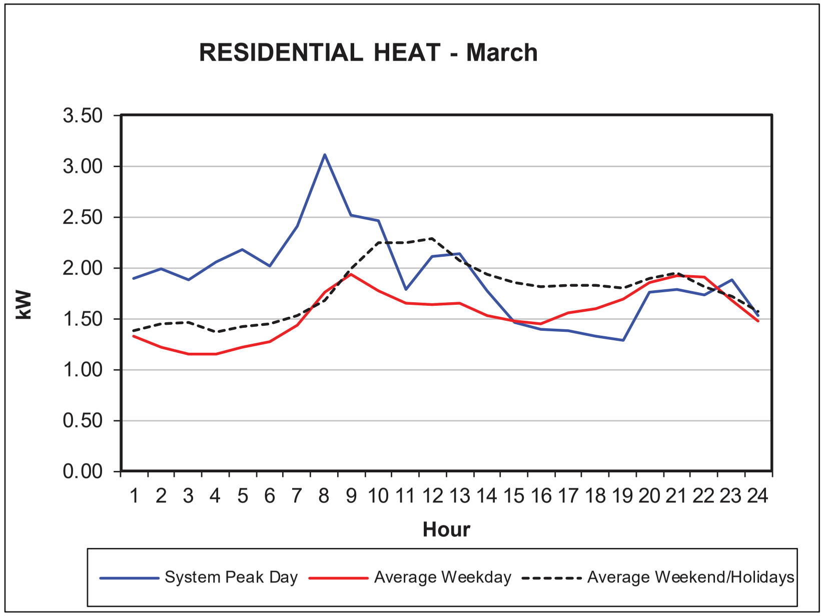


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.8931	1.3303	1.3849
2	1.9881	1.2149	1.4467
3	1.8787	1.1474	1.4593
4	2.0550	1.1542	1.3702
5	2.1820	1.2194	1.4204
6	2.0164	1.2693	1.4490
7	2.4053	1.4348	1.5286
8	3.1176	1.7586	1.6818
9	2.5095	1.9295	1.9895
10	2.4625	1.7717	2.2480
11	1.7915	1.6538	2.2518
12	2.1075	1.6394	2.2799
13	2.1333	1.6527	2.0722
14	1.7745	1.5321	1.9286
15	1.4603	1.4741	1.8594
16	1.3991	1.4531	1.8059
17	1.3773	1.5572	1.8199
18	1.3319	1.5967	1.8216
19	1.2894	1.6942	1.7981
20	1.7581	1.8592	1.8993
21	1.7875	1.9251	1.9430
22	1.7263	1.9058	1.8143
23	1.8855	1.6763	1.7183
24	1.5322	1.4705	1.5714

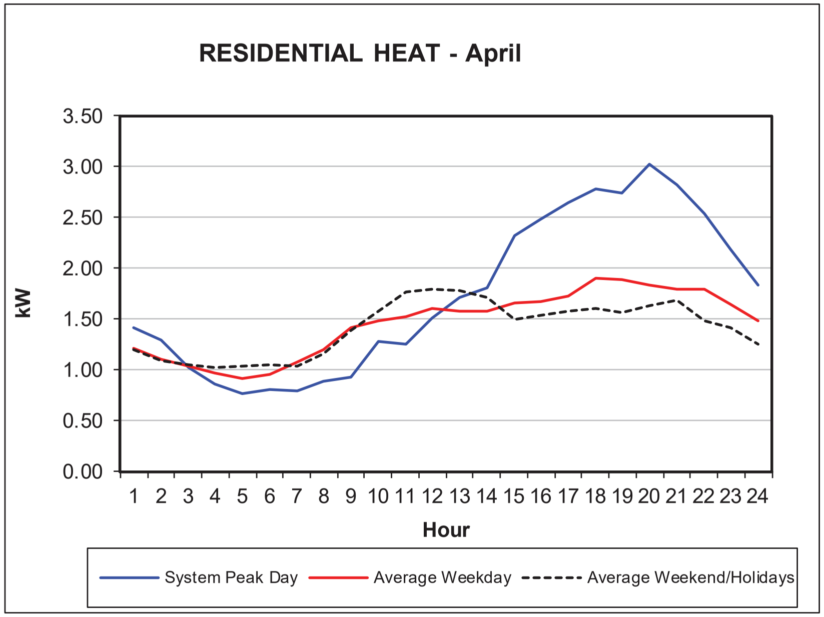


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.4106	1.2053	1.2031
2	1.2880	1.1064	1.0878
3	1.0167	1.0370	1.0512
4	0.8625	0.9682	1.0214
5	0.7715	0.9146	1.0312
6	0.8054	0.9587	1.0472
7	0.7957	1.0731	1.0371
8	0.8875	1.1986	1.1595
9	0.9303	1.4113	1.3944
10	1.2830	1.4857	1.5823
11	1.2497	1.5278	1.7705
12	1.5047	1.5988	1.7927
13	1.7058	1.5734	1.7745
14	1.8065	1.5743	1.7171
15	2.3166	1.6545	1.4914
16	2.4863	1.6780	1.5334
17	2.6466	1.7198	1.5712
18	2.7805	1.8968	1.6033
19	2.7352	1.8908	1.5644
20	3.0194	1.8349	1.6269
21	2.8282	1.8000	1.6882
22	2.5420	1.7967	1.4888
23	2.1831	1.6469	1.4103
24	1.8291	1.4771	1.2509

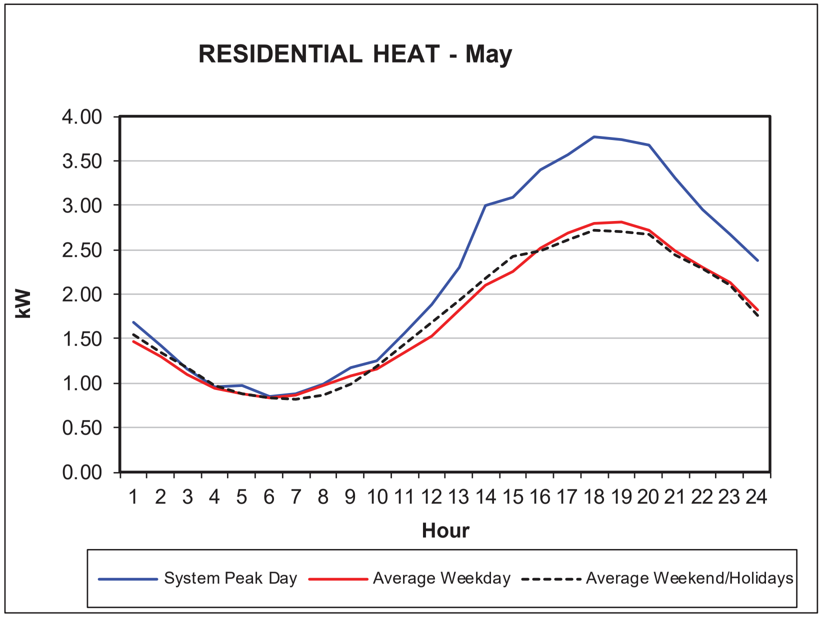


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.6913	1.4729	1.5399
2	1.4212	1.3049	1.3503
3	1.1617	1.1010	1.1760
4	0.9582	0.9378	0.9766
5	0.9695	0.8858	0.8848
6	0.8454	0.8369	0.8311
7	0.8875	0.8664	0.8119
8	0.9953	0.9705	0.8722
9	1.1824	1.0818	0.9906
10	1.2468	1.1555	1.1928
11	1.5591	1.3387	1.4342
12	1.8934	1.5272	1.6805
13	2.2986	1.8180	1.9354
14	2.9991	2.0948	2.1854
15	3.0915	2.2592	2.4241
16	3.4014	2.5144	2.4940
17	3.5715	2.6932	2.6057
18	3.7651	2.7985	2.7135
19	3.7341	2.8126	2.7079
20	3.6852	2.7266	2.6737
21	3.3081	2.4812	2.4381
22	2.9555	2.2984	2.2923
23	2.6701	2.1304	2.1075
24	2.3816	1.8282	1.7582

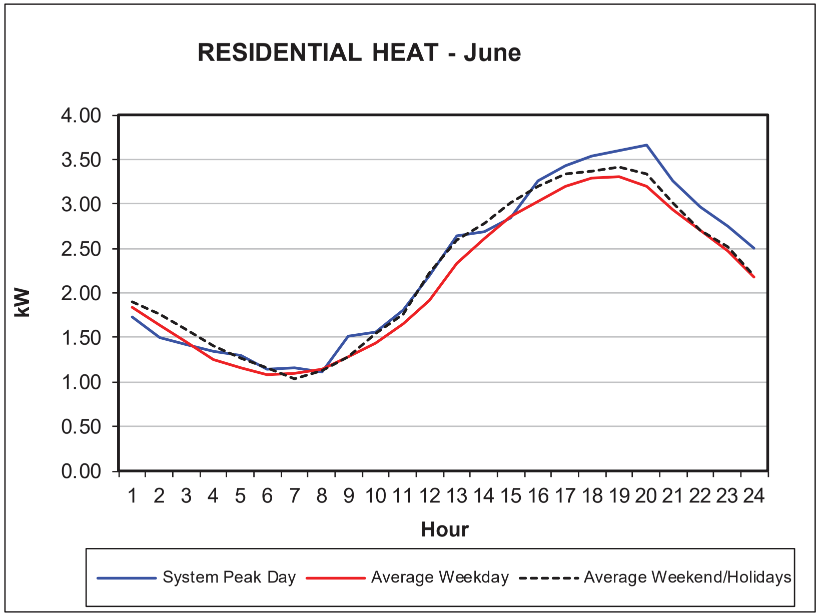


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.7253	1.8427	1.8999
2	1.4924	1.6430	1.7645
3	1.4179	1.4512	1.5880
4	1.3436	1.2543	1.4031
5	1.3022	1.1518	1.2729
6	1.1403	1.0879	1.1655
7	1.1629	1.1035	1.0402
8	1.1067	1.1388	1.1296
9	1.5194	1.2879	1.2907
10	1.5656	1.4405	1.5402
11	1.8070	1.6511	1.7592
12	2.1885	1.9185	2.2242
13	2.6405	2.3290	2.5944
14	2.6903	2.6164	2.7785
15	2.8420	2.8632	3.0143
16	3.2609	3.0353	3.2055
17	3.4269	3.1935	3.3328
18	3.5342	3.2926	3.3763
19	3.5994	3.3145	3.4192
20	3.6685	3.2005	3.3440
21	3.2613	2.9364	3.0216
22	2.9669	2.7075	2.6981
23	2.7474	2.4695	2.5181
24	2.4986	2.1859	2.2003

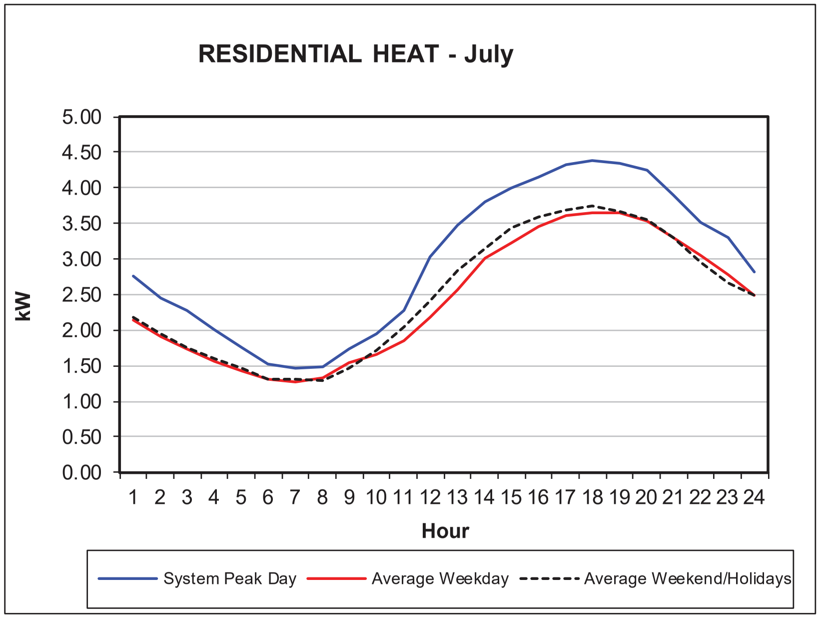


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.7675	2.1336	2.1735
2	2.4473	1.8997	1.9397
3	2.2782	1.7254	1.7589
4	2.0063	1.5599	1.5931
5	1.7479	1.4257	1.4632
6	1.5230	1.3131	1.3159
7	1.4684	1.2774	1.3060
8	1.4783	1.3251	1.2876
9	1.7428	1.5412	1.4574
10	1.9395	1.6632	1.7213
11	2.2749	1.8554	2.0529
12	3.0377	2.1760	2.4201
13	3.4743	2.5717	2.8357
14	3.8088	3.0169	3.1457
15	3.9886	3.2304	3.4358
16	4.1523	3.4468	3.5986
17	4.3150	3.6089	3.6858
18	4.3869	3.6480	3.7388
19	4.3422	3.6554	3.6756
20	4.2552	3.5311	3.5484
21	3.9029	3.2921	3.3015
22	3.5034	3.0572	2.9467
23	3.2954	2.7732	2.6635
24	2.8220	2.4960	2.4834

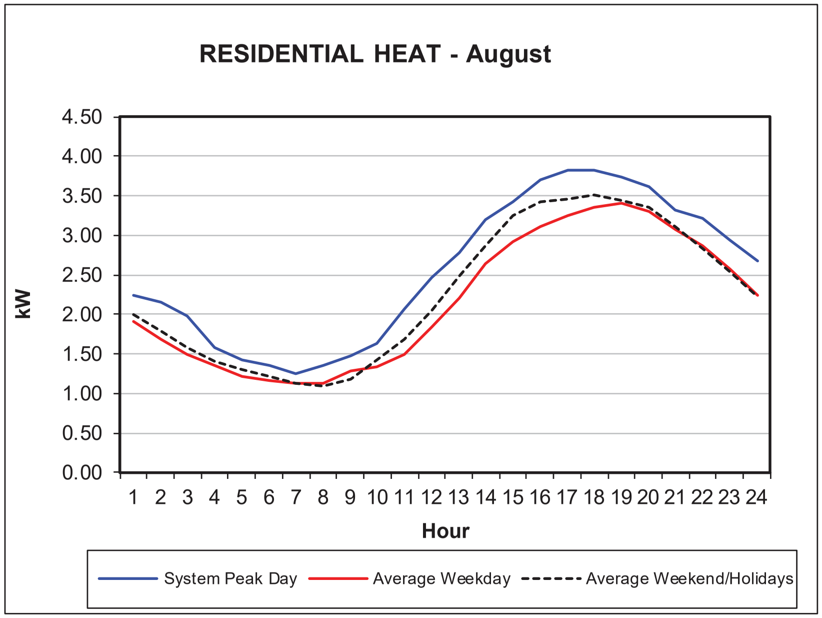


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.2365	1.9129	1.9995
2	2.1479	1.6871	1.7826
3	1.9864	1.4885	1.5805
4	1.5721	1.3459	1.4102
5	1.4240	1.2192	1.3086
6	1.3545	1.1575	1.2151
7	1.2571	1.1204	1.1193
8	1.3522	1.1307	1.0923
9	1.4783	1.2800	1.1866
10	1.6341	1.3271	1.4293
11	2.0657	1.4840	1.6774
12	2.4583	1.8329	2.0537
13	2.7762	2.2123	2.4886
14	3.2019	2.6315	2.8732
15	3.4301	2.9174	3.2502
16	3.7021	3.1169	3.4242
17	3.8226	3.2444	3.4579
18	3.8210	3.3579	3.5136
19	3.7312	3.4117	3.4417
20	3.6073	3.3093	3.3611
21	3.3237	3.0722	3.1040
22	3.2156	2.8639	2.8391
23	2.9282	2.5733	2.5306
24	2.6821	2.2370	2.2249

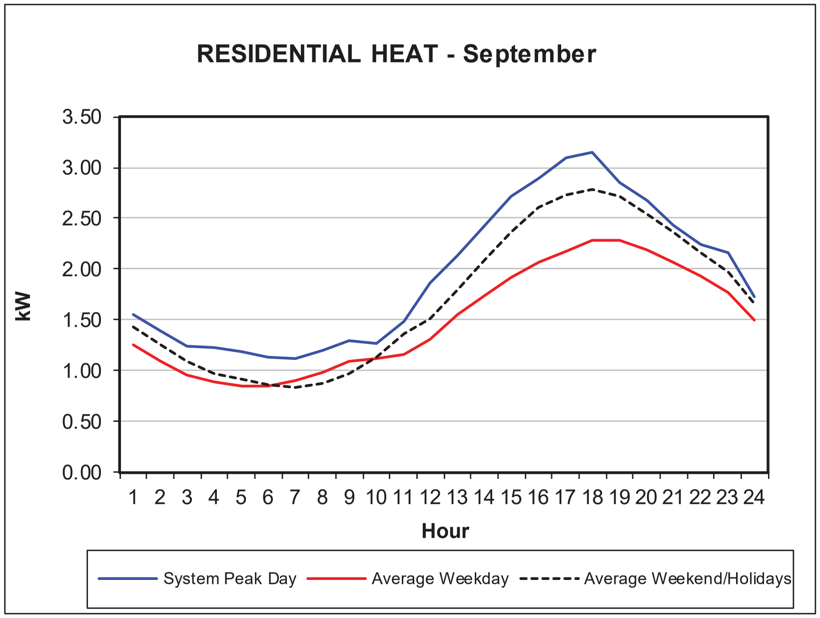


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.5573	1.2506	1.4298
2	1.3867	1.0950	1.2591
3	1.2371	0.9635	1.0958
4	1.2329	0.8924	0.9758
5	1.1832	0.8468	0.9107
6	1.1335	0.8550	0.8622
7	1.1193	0.9098	0.8293
8	1.1960	0.9781	0.8771
9	1.2932	1.0952	0.9760
10	1.2733	1.1212	1.1369
11	1.4915	1.1614	1.3605
12	1.8573	1.3041	1.5054
13	2.1408	1.5468	1.7930
14	2.4277	1.7430	2.0996
15	2.7167	1.9214	2.3652
16	2.8966	2.0673	2.6030
17	3.0942	2.1714	2.7280
18	3.1454	2.2824	2.7845
19	2.8548	2.2805	2.7179
20	2.6732	2.1933	2.5435
21	2.4343	2.0688	2.3637
22	2.2450	1.9310	2.1635
23	2.1557	1.7660	1.9661
24	1.7285	1.4990	1.6647

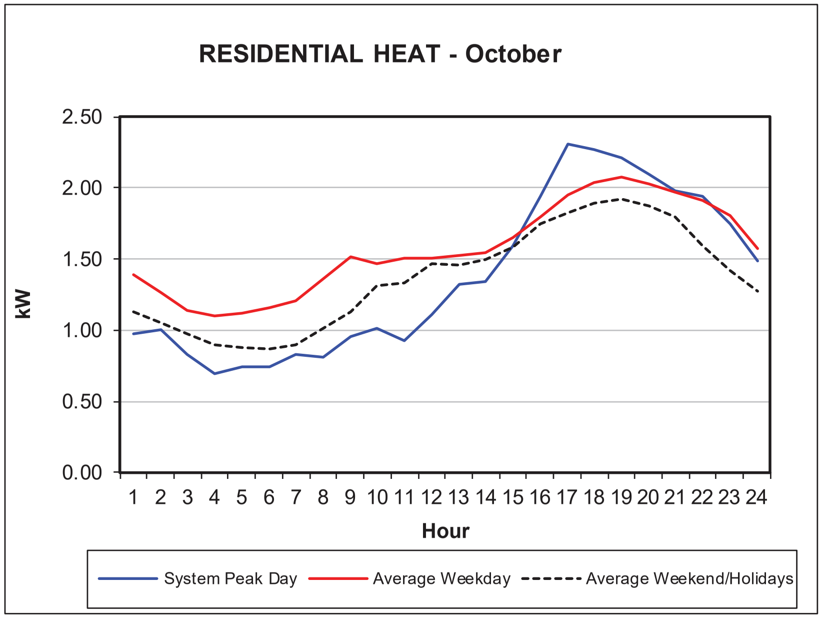


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9770	1.3868	1.1275
2	1.0043	1.2656	1.0552
3	0.8325	1.1355	0.9704
4	0.6980	1.0979	0.8997
5	0.7389	1.1215	0.8814
6	0.7437	1.1535	0.8666
7	0.8297	1.2033	0.9003
8	0.8055	1.3621	1.0155
9	0.9504	1.5196	1.1262
10	1.0139	1.4675	1.3101
11	0.9285	1.5020	1.3282
12	1.1075	1.5048	1.4652
13	1.3244	1.5228	1.4575
14	1.3383	1.5396	1.4975
15	1.5913	1.6458	1.5847
16	1.9393	1.7990	1.7505
17	2.3024	1.9538	1.8217
18	2.2672	2.0380	1.8947
19	2.2104	2.0720	1.9207
20	2.0906	2.0254	1.8757
21	1.9748	1.9681	1.7937
22	1.9377	1.9073	1.5964
23	1.7450	1.8064	1.4144
24	1.4844	1.5774	1.2697

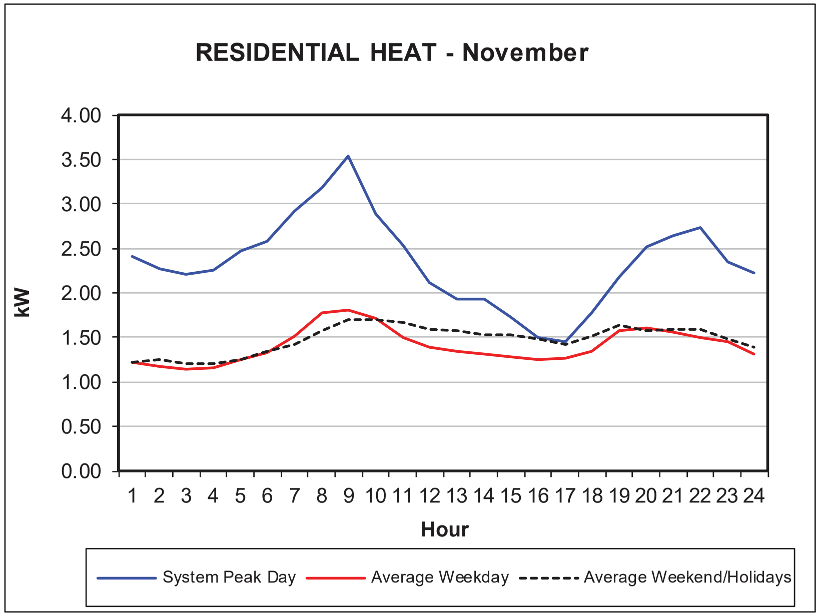


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.4100	1.2143	1.2266
2	2.2684	1.1778	1.2455
3	2.2056	1.1410	1.2007
4	2.2524	1.1622	1.2059
5	2.4662	1.2570	1.2501
6	2.5793	1.3229	1.3480
7	2.9244	1.5118	1.4289
8	3.1848	1.7828	1.5815
9	3.5377	1.8138	1.7002
10	2.8845	1.7117	1.7079
11	2.5378	1.4956	1.6769
12	2.1251	1.3887	1.5978
13	1.9287	1.3411	1.5794
14	1.9307	1.3188	1.5338
15	1.7366	1.2816	1.5228
16	1.4951	1.2561	1.4775
17	1.4505	1.2689	1.4299
18	1.7732	1.3504	1.5141
19	2.1733	1.5730	1.6417
20	2.5227	1.6016	1.5717
21	2.6448	1.5682	1.5949
22	2.7341	1.5025	1.5947
23	2.3443	1.4568	1.4804
24	2.2305	1.3110	1.3923

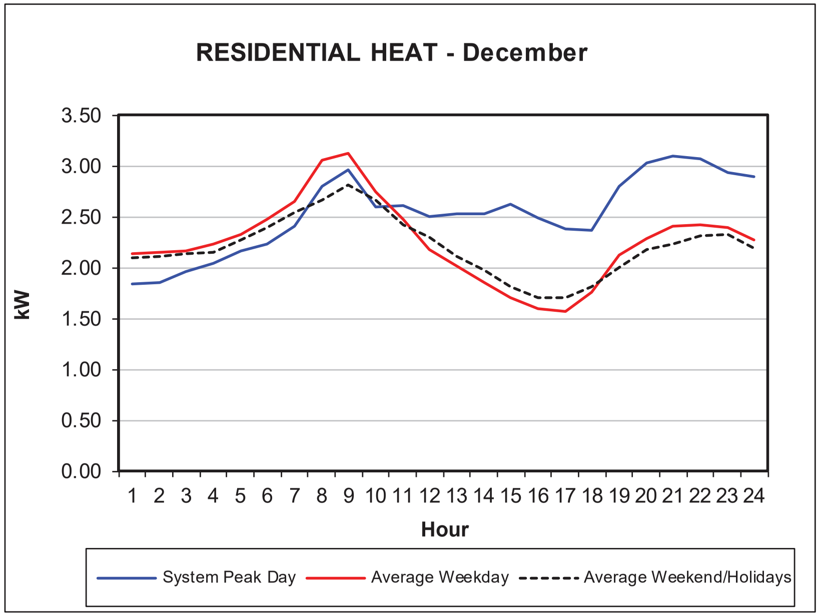


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-8.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.8374	2.1381	2.0990
2	1.8543	2.1522	2.1151
3	1.9590	2.1689	2.1339
4	2.0452	2.2317	2.1550
5	2.1678	2.3224	2.2660
6	2.2311	2.4690	2.3982
7	2.4135	2.6519	2.5489
8	2.7999	3.0597	2.6708
9	2.9670	3.1246	2.8070
10	2.5912	2.7444	2.6584
11	2.6160	2.4705	2.4201
12	2.5001	2.1755	2.2944
13	2.5251	2.0185	2.1058
14	2.5361	1.8596	1.9735
15	2.6255	1.6987	1.8135
16	2.4954	1.5920	1.7073
17	2.3740	1.5758	1.6999
18	2.3652	1.7610	1.8068
19	2.8049	2.1247	2.0082
20	3.0323	2.2910	2.1710
21	3.1033	2.4074	2.2308
22	3.0770	2.4263	2.3142
23	2.9390	2.3980	2.3257
24	2.8979	2.2719	2.1900

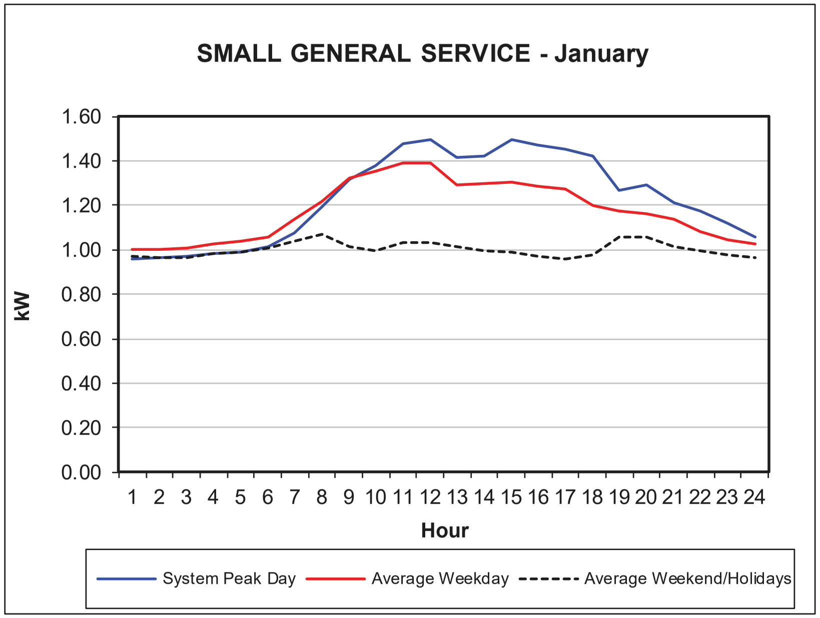


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9567	0.9994	0.9684
2	0.9662	0.9988	0.9641
3	0.9731	1.0068	0.9675
4	0.9846	1.0255	0.9833
5	0.9920	1.0412	0.9918
6	1.0149	1.0563	1.0075
7	1.0752	1.1363	1.0376
8	1.1919	1.2186	1.0696
9	1.3191	1.3207	1.0113
10	1.3809	1.3551	0.9927
11	1.4741	1.3889	1.0314
12	1.4929	1.3895	1.0342
13	1.4169	1.2913	1.0124
14	1.4219	1.3008	0.9966
15	1.4969	1.3040	0.9872
16	1.4692	1.2840	0.9710
17	1.4496	1.2709	0.9600
18	1.4196	1.1986	0.9750
19	1.2677	1.1771	1.0599
20	1.2936	1.1641	1.0576
21	1.2125	1.1388	1.0169
22	1.1747	1.0842	0.9927
23	1.1186	1.0428	0.9784
24	1.0593	1.0250	0.9645

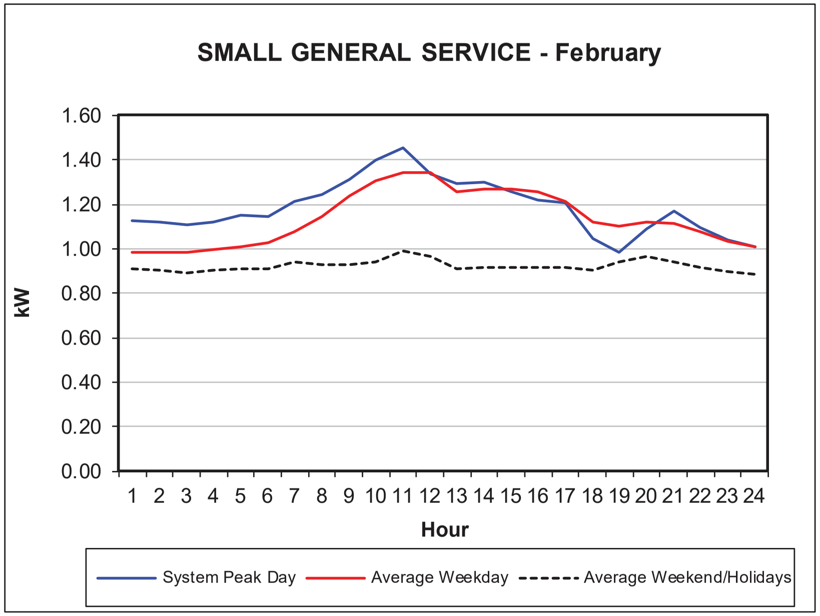


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1291	0.9855	0.9113
2	1.1197	0.9827	0.9060
3	1.1052	0.9818	0.8937
4	1.1225	0.9958	0.9013
5	1.1503	1.0105	0.9095
6	1.1429	1.0261	0.9102
7	1.2139	1.0792	0.9397
8	1.2428	1.1469	0.9313
9	1.3119	1.2359	0.9257
10	1.3990	1.3066	0.9394
11	1.4525	1.3436	0.9876
12	1.3394	1.3407	0.9629
13	1.2956	1.2588	0.9091
14	1.3021	1.2676	0.9173
15	1.2579	1.2691	0.9152
16	1.2165	1.2590	0.9135
17	1.2054	1.2147	0.9151
18	1.0443	1.1194	0.9037
19	0.9830	1.0985	0.9384
20	1.0899	1.1191	0.9658
21	1.1724	1.1129	0.9433
22	1.0924	1.0739	0.9133
23	1.0395	1.0365	0.8988
24	1.0071	1.0095	0.8833

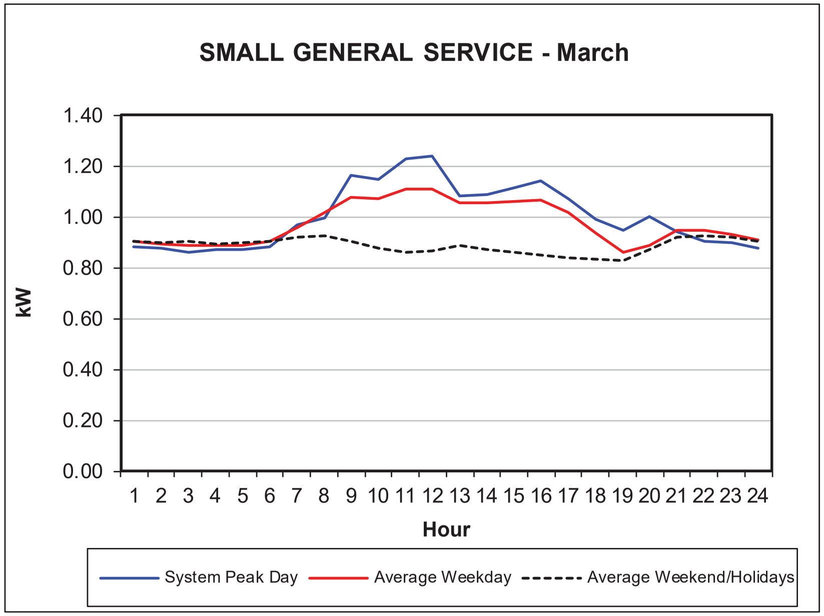


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8831	0.9022	0.9016
2	0.8754	0.8927	0.8960
3	0.8584	0.8874	0.9013
4	0.8723	0.8877	0.8920
5	0.8708	0.8893	0.8992
6	0.8812	0.9023	0.9058
7	0.9665	0.9571	0.9202
8	0.9956	1.0146	0.9254
9	1.1646	1.0759	0.9040
10	1.1490	1.0710	0.8741
11	1.2294	1.1110	0.8629
12	1.2372	1.1088	0.8663
13	1.0803	1.0571	0.8887
14	1.0865	1.0533	0.8716
15	1.1131	1.0615	0.8621
16	1.1438	1.0639	0.8507
17	1.0725	1.0187	0.8372
18	0.9917	0.9372	0.8352
19	0.9491	0.8602	0.8280
20	1.0028	0.8870	0.8696
21	0.9421	0.9485	0.9181
22	0.9036	0.9470	0.9275
23	0.8973	0.9287	0.9185
24	0.8763	0.9067	0.9062

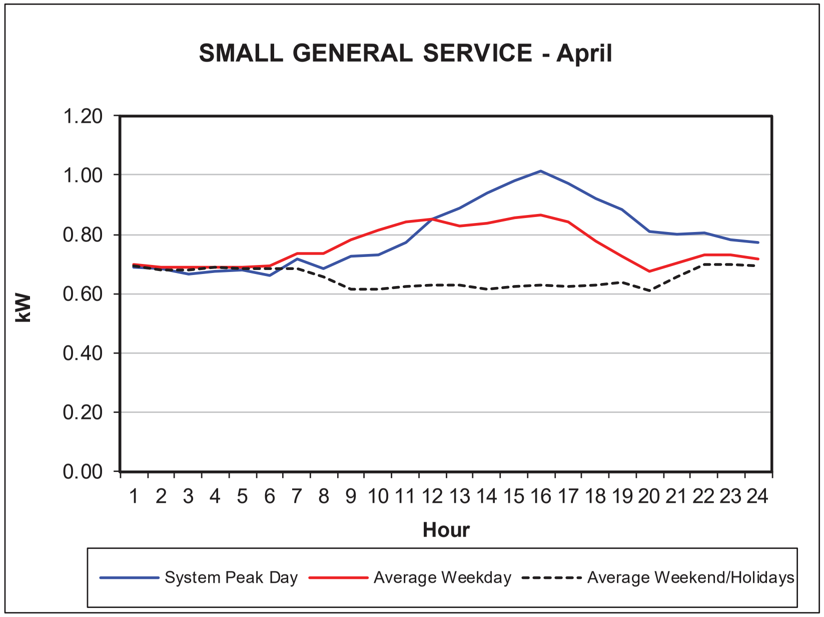


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6913	0.6994	0.6926
2	0.6839	0.6868	0.6807
3	0.6644	0.6896	0.6810
4	0.6755	0.6882	0.6895
5	0.6779	0.6898	0.6825
6	0.6627	0.6942	0.6848
7	0.7180	0.7345	0.6824
8	0.6864	0.7343	0.6584
9	0.7253	0.7806	0.6168
10	0.7323	0.8140	0.6133
11	0.7731	0.8419	0.6221
12	0.8504	0.8508	0.6311
13	0.8889	0.8289	0.6267
14	0.9408	0.8390	0.6161
15	0.9831	0.8542	0.6243
16	1.0159	0.8674	0.6293
17	0.9720	0.8435	0.6265
18	0.9214	0.7761	0.6273
19	0.8861	0.7255	0.6377
20	0.8099	0.6730	0.6110
21	0.8017	0.7031	0.6564
22	0.8032	0.7309	0.6964
23	0.7808	0.7300	0.7004
24	0.7747	0.7155	0.6923

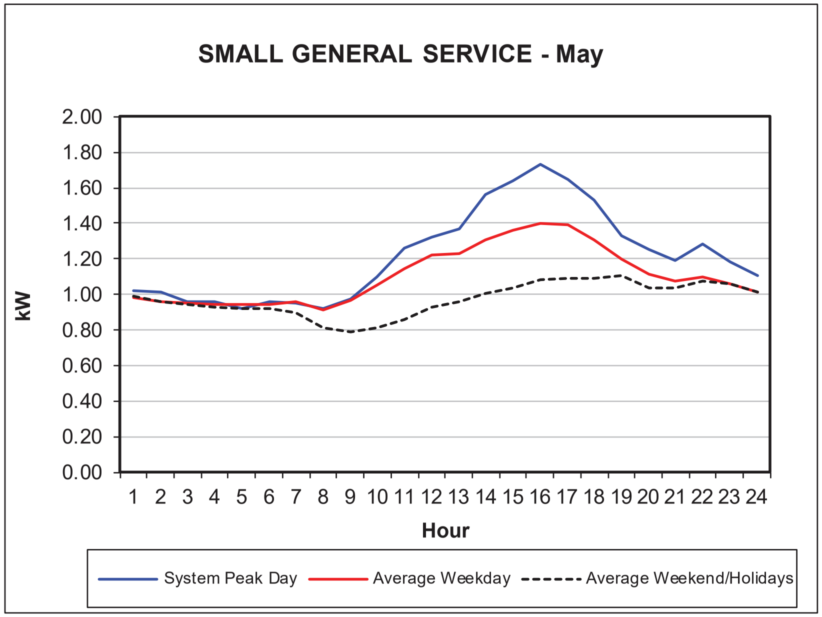


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0219	0.9808	0.9881
2	1.0092	0.9605	0.9615
3	0.9573	0.9512	0.9422
4	0.9594	0.9415	0.9271
5	0.9198	0.9397	0.9218
6	0.9600	0.9429	0.9216
7	0.9534	0.9618	0.8966
8	0.9179	0.9120	0.8153
9	0.9737	0.9642	0.7922
10	1.0944	1.0496	0.8149
11	1.2627	1.1418	0.8599
12	1.3228	1.2198	0.9240
13	1.3663	1.2269	0.9622
14	1.5577	1.3067	1.0019
15	1.6368	1.3579	1.0355
16	1.7345	1.3961	1.0787
17	1.6467	1.3897	1.0907
18	1.5268	1.3049	1.0866
19	1.3301	1.2014	1.1061
20	1.2548	1.1163	1.0342
21	1.1927	1.0733	1.0333
22	1.2808	1.0983	1.0739
23	1.1810	1.0605	1.0600
24	1.1047	1.0124	1.0145

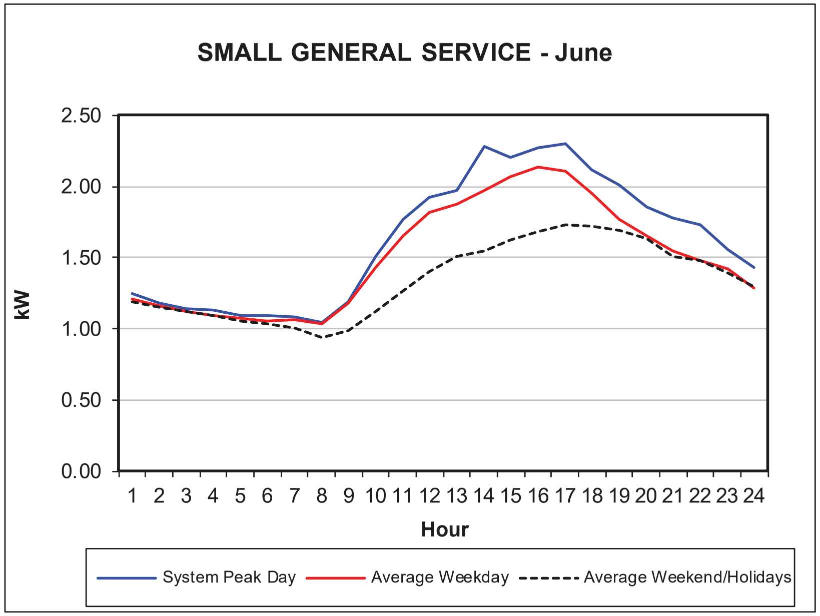


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.2468	1.2114	1.1837
2	1.1758	1.1582	1.1499
3	1.1354	1.1254	1.1218
4	1.1316	1.0949	1.0892
5	1.0961	1.0729	1.0539
6	1.0960	1.0529	1.0345
7	1.0855	1.0604	1.0009
8	1.0445	1.0299	0.9374
9	1.1848	1.1772	0.9814
10	1.5087	1.4276	1.1240
11	1.7706	1.6568	1.2615
12	1.9259	1.8196	1.4005
13	1.9756	1.8699	1.5094
14	2.2755	1.9736	1.5413
15	2.2011	2.0647	1.6212
16	2.2753	2.1383	1.6822
17	2.2958	2.1063	1.7325
18	2.1168	1.9482	1.7218
19	2.0119	1.7647	1.6894
20	1.8505	1.6483	1.6290
21	1.7799	1.5499	1.5027
22	1.7264	1.4768	1.4780
23	1.5576	1.4230	1.3882
24	1.4294	1.2853	1.2905

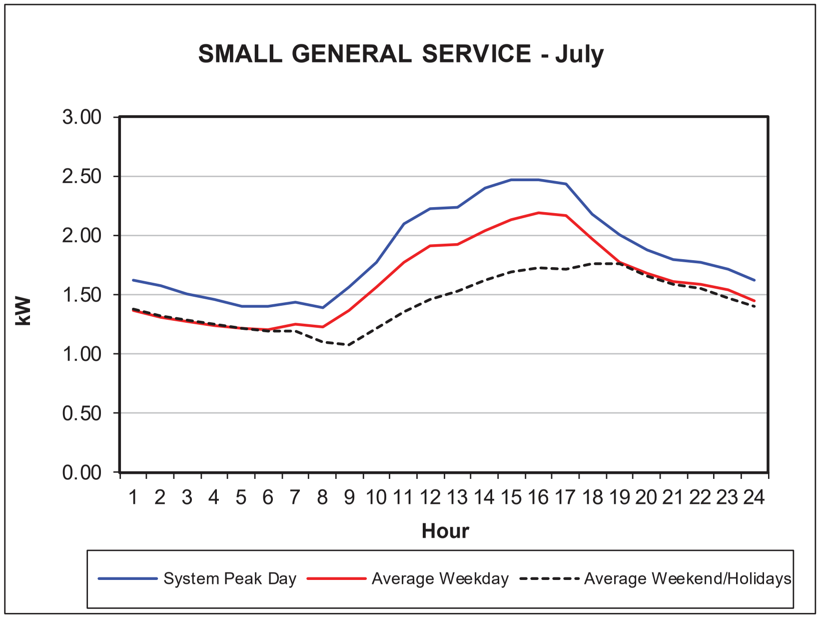


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.6161	1.3704	1.3763
2	1.5726	1.3072	1.3198
3	1.5020	1.2704	1.2807
4	1.4549	1.2338	1.2449
5	1.3947	1.2120	1.2145
6	1.4048	1.1994	1.1970
7	1.4304	1.2460	1.1862
8	1.3892	1.2267	1.0944
9	1.5623	1.3623	1.0755
10	1.7663	1.5612	1.2108
11	2.0927	1.7683	1.3567
12	2.2285	1.9149	1.4544
13	2.2299	1.9205	1.5310
14	2.3959	2.0373	1.6257
15	2.4700	2.1310	1.6957
16	2.4700	2.1868	1.7267
17	2.4337	2.1646	1.7157
18	2.1767	1.9717	1.7553
19	1.9978	1.7748	1.7580
20	1.8809	1.6769	1.6518
21	1.7921	1.6137	1.5873
22	1.7756	1.5891	1.5561
23	1.7135	1.5403	1.4736
24	1.6175	1.4515	1.4059

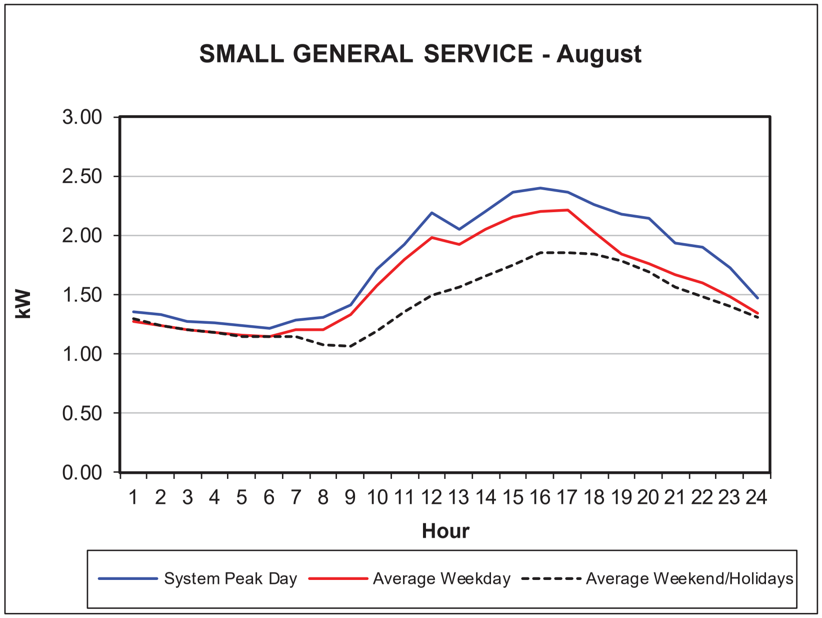


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.3575	1.2742	1.3004
2	1.3266	1.2333	1.2419
3	1.2775	1.2055	1.2075
4	1.2661	1.1794	1.1805
5	1.2393	1.1528	1.1487
6	1.2136	1.1482	1.1417
7	1.2859	1.2003	1.1492
8	1.3028	1.2042	1.0780
9	1.4072	1.3332	1.0639
10	1.7182	1.5744	1.1890
11	1.9189	1.7992	1.3510
12	2.1925	1.9803	1.4965
13	2.0552	1.9192	1.5582
14	2.2024	2.0461	1.6516
15	2.3576	2.1520	1.7434
16	2.3996	2.1963	1.8524
17	2.3669	2.2070	1.8491
18	2.2544	2.0294	1.8451
19	2.1721	1.8368	1.7816
20	2.1474	1.7550	1.6874
21	1.9364	1.6625	1.5678
22	1.8983	1.5953	1.4843
23	1.7292	1.4870	1.3947
24	1.4747	1.3377	1.3105

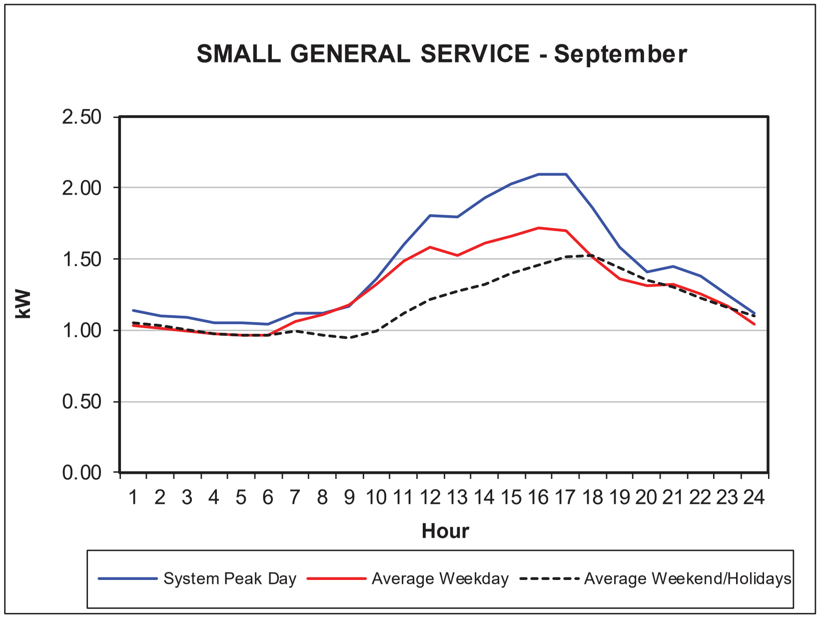


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1351	1.0273	1.0557
2	1.1021	1.0101	1.0278
3	1.0896	0.9949	1.0055
4	1.0556	0.9715	0.9715
5	1.0484	0.9680	0.9678
6	1.0409	0.9637	0.9630
7	1.1193	1.0609	0.9909
8	1.1156	1.1047	0.9683
9	1.1624	1.1792	0.9425
10	1.3572	1.3233	0.9902
11	1.6034	1.4881	1.1154
12	1.8051	1.5864	1.2154
13	1.7933	1.5204	1.2721
14	1.9300	1.6083	1.3177
15	2.0273	1.6641	1.4003
16	2.0956	1.7165	1.4542
17	2.0964	1.7032	1.5169
18	1.8595	1.5123	1.5234
19	1.5801	1.3586	1.4386
20	1.4116	1.3092	1.3521
21	1.4431	1.3259	1.3059
22	1.3751	1.2533	1.2223
23	1.2460	1.1623	1.1615
24	1.1199	1.0460	1.1006

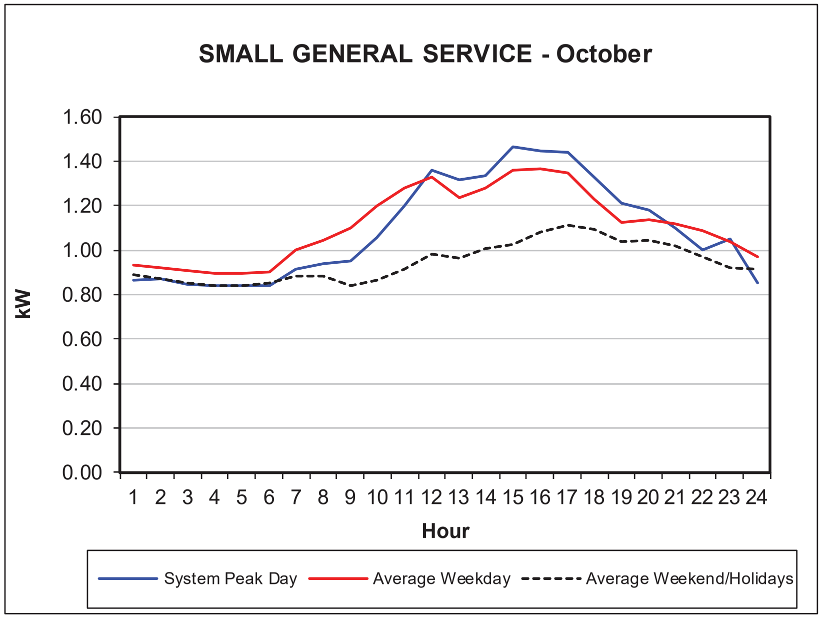


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8646	0.9346	0.8869
2	0.8718	0.9223	0.8729
3	0.8485	0.9100	0.8538
4	0.8414	0.8933	0.8405
5	0.8384	0.8959	0.8421
6	0.8380	0.9028	0.8539
7	0.9114	0.9984	0.8832
8	0.9365	1.0457	0.8827
9	0.9480	1.0975	0.8411
10	1.0540	1.2007	0.8621
11	1.1987	1.2807	0.9137
12	1.3606	1.3288	0.9821
13	1.3163	1.2364	0.9623
14	1.3327	1.2772	1.0088
15	1.4670	1.3587	1.0247
16	1.4465	1.3654	1.0836
17	1.4383	1.3492	1.1125
18	1.3280	1.2297	1.0936
19	1.2107	1.1249	1.0392
20	1.1824	1.1364	1.0410
21	1.1003	1.1157	1.0180
22	1.0033	1.0869	0.9692
23	1.0495	1.0378	0.9212
24	0.8550	0.9723	0.9144

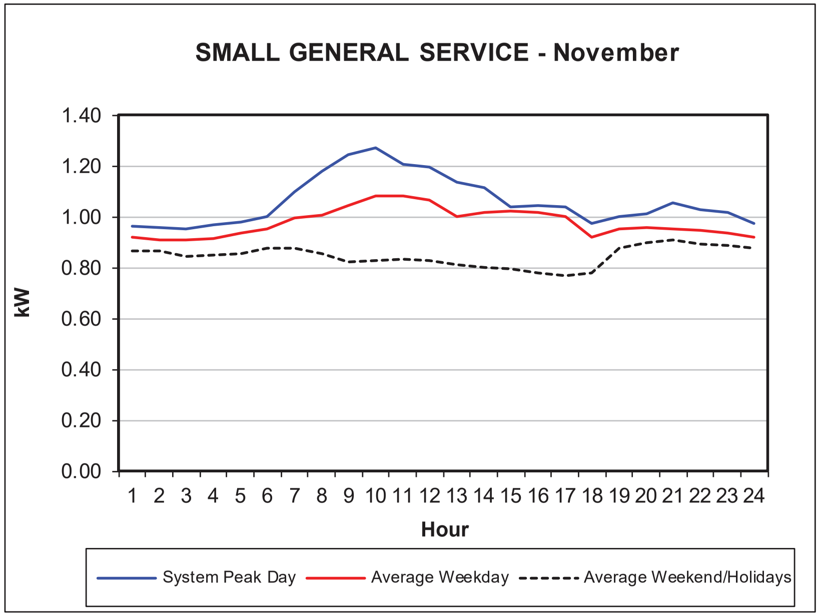


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9656	0.9176	0.8631
2	0.9598	0.9103	0.8631
3	0.9513	0.9085	0.8463
4	0.9692	0.9136	0.8513
5	0.9788	0.9347	0.8574
6	0.9992	0.9507	0.8742
7	1.0999	0.9959	0.8766
8	1.1804	1.0064	0.8525
9	1.2471	1.0463	0.8201
10	1.2713	1.0816	0.8283
11	1.2072	1.0843	0.8358
12	1.1953	1.0634	0.8255
13	1.1353	1.0002	0.8098
14	1.1125	1.0147	0.7989
15	1.0398	1.0200	0.7970
16	1.0456	1.0171	0.7796
17	1.0402	1.0035	0.7660
18	0.9723	0.9198	0.7810
19	1.0020	0.9515	0.8782
20	1.0112	0.9602	0.8980
21	1.0529	0.9546	0.9063
22	1.0297	0.9449	0.8911
23	1.0190	0.9364	0.8855
24	0.9763	0.9182	0.8748

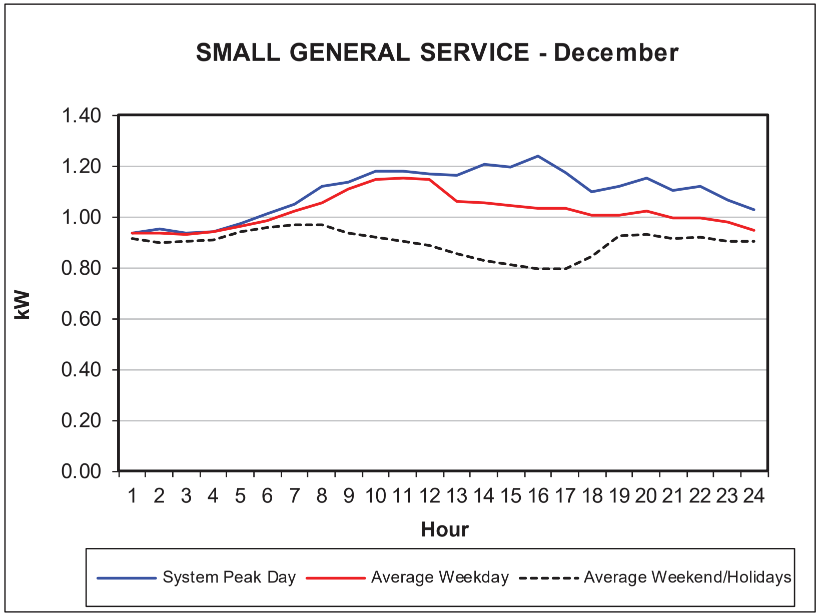


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-9.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9377	0.9369	0.9143
2	0.9512	0.9341	0.9008
3	0.9360	0.9304	0.9015
4	0.9396	0.9388	0.9092
5	0.9755	0.9629	0.9432
6	1.0093	0.9822	0.9558
7	1.0517	1.0234	0.9697
8	1.1205	1.0540	0.9689
9	1.1377	1.1093	0.9362
10	1.1813	1.1493	0.9184
11	1.1805	1.1525	0.9036
12	1.1691	1.1494	0.8855
13	1.1624	1.0632	0.8531
14	1.2069	1.0559	0.8300
15	1.1966	1.0447	0.8132
16	1.2399	1.0348	0.7935
17	1.1761	1.0319	0.7979
18	1.1003	1.0069	0.8459
19	1.1181	1.0075	0.9239
20	1.1544	1.0200	0.9294
21	1.1012	0.9957	0.9168
22	1.1183	0.9955	0.9204
23	1.0655	0.9770	0.9062
24	1.0288	0.9476	0.9023

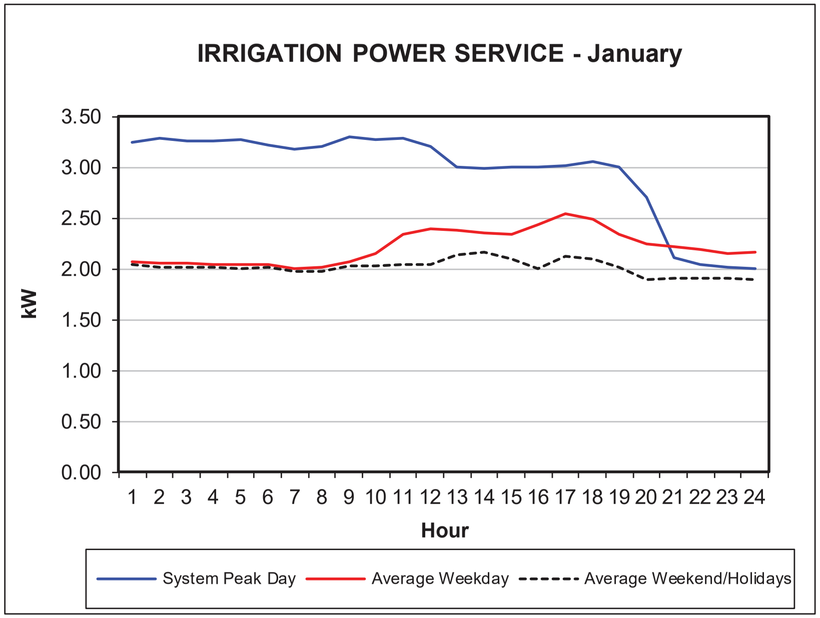


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.1

Jan-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3.2411	2.0730	2.0483
2	3.2827	2.0501	2.0202
3	3.2567	2.0495	2.0192
4	3.2543	2.0482	2.0145
5	3.2761	2.0376	2.0077
6	3.2137	2.0365	2.0146
7	3.1830	2.0024	1.9754
8	3.2000	2.0115	1.9766
9	3.2996	2.0661	2.0321
10	3.2730	2.1475	2.0343
11	3.2844	2.3360	2.0431
12	3.2064	2.3916	2.0464
13	2.9982	2.3738	2.1363
14	2.9836	2.3470	2.1705
15	3.0065	2.3408	2.0972
16	3.0049	2.4386	2.0009
17	3.0160	2.5406	2.1211
18	3.0526	2.4879	2.0904
19	3.0015	2.3429	2.0216
20	2.6973	2.2506	1.8957
21	2.1041	2.2127	1.9062
22	2.0427	2.1922	1.9034
23	2.0135	2.1525	1.9029
24	1.9965	2.1668	1.8997

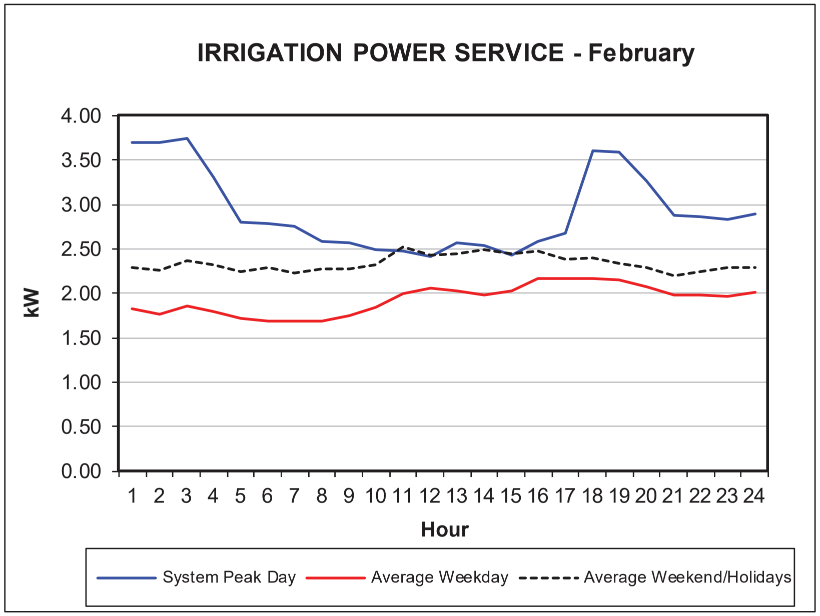


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.2

Feb-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3.6970	1.8187	2.2918
2	3.7021	1.7638	2.2664
3	3.7371	1.8503	2.3683
4	3.3156	1.7879	2.3145
5	2.8038	1.7209	2.2488
6	2.7884	1.6917	2.2869
7	2.7503	1.6857	2.2269
8	2.5787	1.6917	2.2735
9	2.5723	1.7509	2.2678
10	2.4930	1.8407	2.3150
11	2.4715	1.9989	2.5290
12	2.4189	2.0532	2.4224
13	2.5741	2.0309	2.4450
14	2.5406	1.9744	2.4984
15	2.4231	2.0283	2.4380
16	2.5864	2.1586	2.4688
17	2.6777	2.1642	2.3844
18	3.6071	2.1597	2.3938
19	3.5867	2.1538	2.3285
20	3.2596	2.0747	2.2838
21	2.8733	1.9797	2.2010
22	2.8567	1.9757	2.2505
23	2.8346	1.9686	2.2898
24	2.8986	2.0152	2.2957

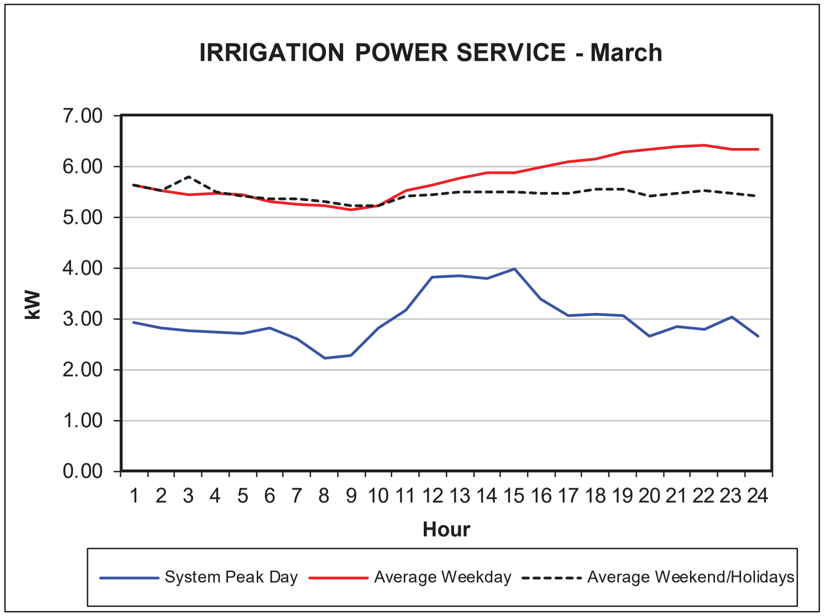


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.3

Mar-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.9327	5.6402	5.6370
2	2.8072	5.5319	5.5130
3	2.7518	5.4408	5.7965
4	2.7356	5.4652	5.4889
5	2.6966	5.4291	5.4027
6	2.8211	5.2977	5.3528
7	2.5935	5.2488	5.3699
8	2.2295	5.2162	5.3127
9	2.2833	5.1330	5.2213
10	2.8057	5.2253	5.2207
11	3.1641	5.5121	5.3993
12	3.8089	5.6316	5.4304
13	3.8523	5.7696	5.4962
14	3.7818	5.8717	5.5007
15	3.9834	5.8571	5.4926
16	3.3787	5.9806	5.4735
17	3.0594	6.0827	5.4621
18	3.0952	6.1316	5.5458
19	3.0460	6.2651	5.5357
20	2.6615	6.3348	5.4016
21	2.8386	6.3843	5.4701
22	2.7848	6.4060	5.5059
23	3.0218	6.3379	5.4665
24	2.6501	6.3224	5.4036

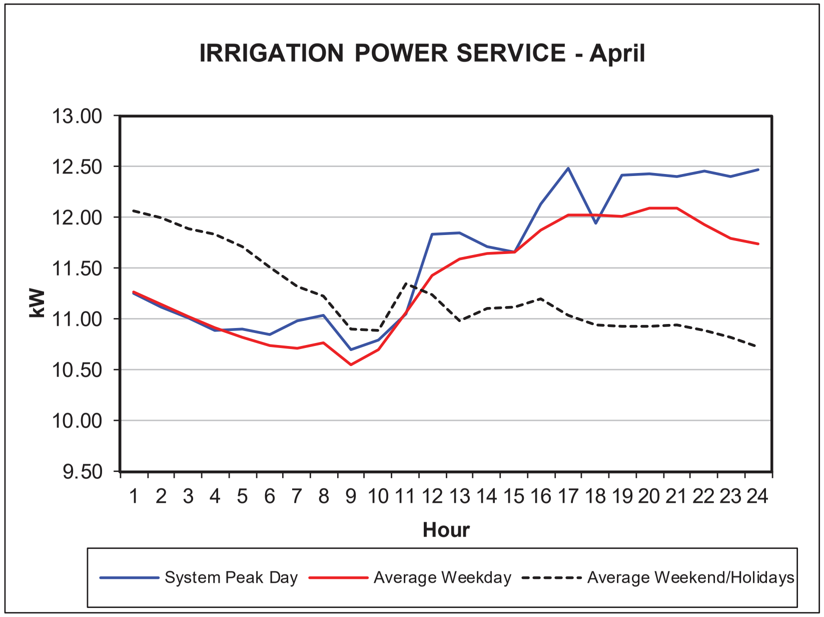


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.4

Apr-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.2508	11.2690	12.0605
2	11.1126	11.1415	11.9923
3	11.0145	11.0223	11.8881
4	10.8833	10.9185	11.8403
5	10.8956	10.8194	11.7191
6	10.8482	10.7367	11.5112
7	10.9793	10.7126	11.3183
8	11.0338	10.7628	11.2213
9	10.6991	10.5503	10.8992
10	10.7874	10.7044	10.8894
11	11.0507	11.0672	11.3421
12	11.8317	11.4279	11.2421
13	11.8525	11.5949	10.9863
14	11.7182	11.6407	11.1006
15	11.6569	11.6541	11.1127
16	12.1324	11.8786	11.1966
17	12.4815	12.0245	11.0387
18	11.9460	12.0190	10.9366
19	12.4188	12.0156	10.9307
20	12.4235	12.0929	10.9251
21	12.3999	12.0974	10.9418
22	12.4527	11.9342	10.8945
23	12.3995	11.7995	10.8241
24	12.4678	11.7401	10.7241

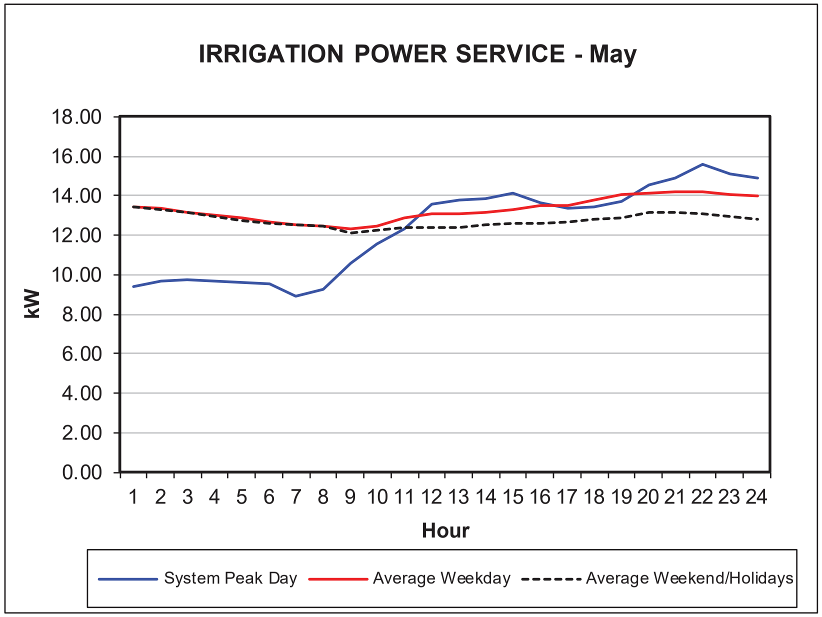


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.5

May-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.3874	13.4559	13.3970
2	9.6958	13.3769	13.2703
3	9.7670	13.1194	13.1387
4	9.6622	13.0225	12.9583
5	9.6141	12.8737	12.7224
6	9.5220	12.6940	12.5936
7	8.9000	12.5491	12.4987
8	9.2606	12.4276	12.4256
9	10.5589	12.3043	12.1116
10	11.5417	12.4608	12.2191
11	12.3096	12.8503	12.4091
12	13.5524	13.1125	12.3648
13	13.7430	13.0798	12.3687
14	13.8177	13.1293	12.5266
15	14.1073	13.3070	12.6204
16	13.6058	13.5199	12.6054
17	13.3907	13.5131	12.6782
18	13.4259	13.7409	12.7656
19	13.6914	14.0361	12.8544
20	14.5675	14.1255	13.1269
21	14.8968	14.2111	13.1812
22	15.5867	14.1790	13.1065
23	15.0895	14.0499	12.9142
24	14.9148	14.0035	12.7883

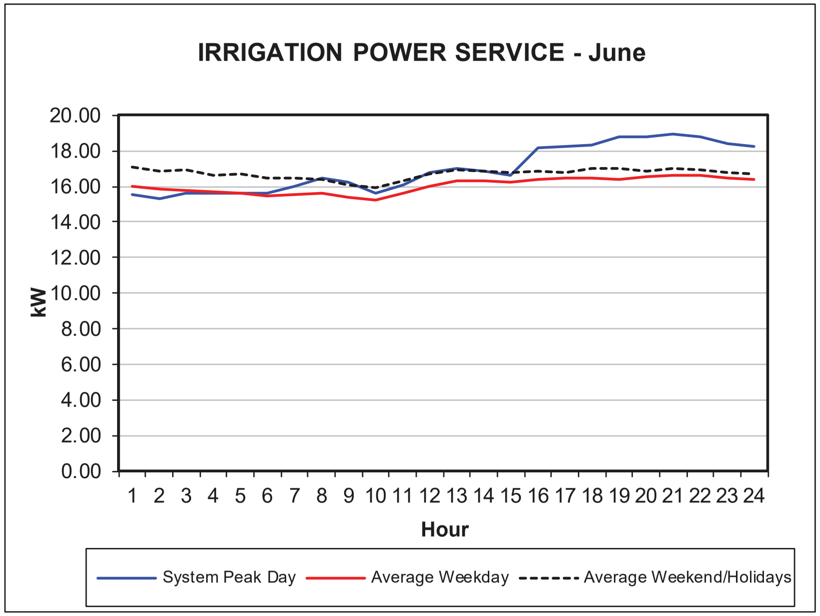


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.6

Jun-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.5692	15.9834	17.0881
2	15.3425	15.8699	16.8305
3	15.6199	15.7871	16.9133
4	15.6030	15.6953	16.6144
5	15.6294	15.6112	16.6666
6	15.6098	15.4889	16.4328
7	15.9787	15.5079	16.4620
8	16.4438	15.6004	16.3980
9	16.1993	15.3592	16.0536
10	15.5846	15.2556	15.9434
11	16.1006	15.6156	16.3416
12	16.7598	16.0029	16.7247
13	16.9971	16.3141	16.9265
14	16.8140	16.3033	16.8358
15	16.6263	16.2470	16.7776
16	18.1322	16.4196	16.8749
17	18.2296	16.4622	16.7738
18	18.3155	16.4785	16.9842
19	18.7943	16.4233	17.0110
20	18.7629	16.5651	16.8510
21	18.9635	16.6283	16.9745
22	18.7744	16.6299	16.9295
23	18.4239	16.4963	16.7449
24	18.2041	16.3803	16.6892

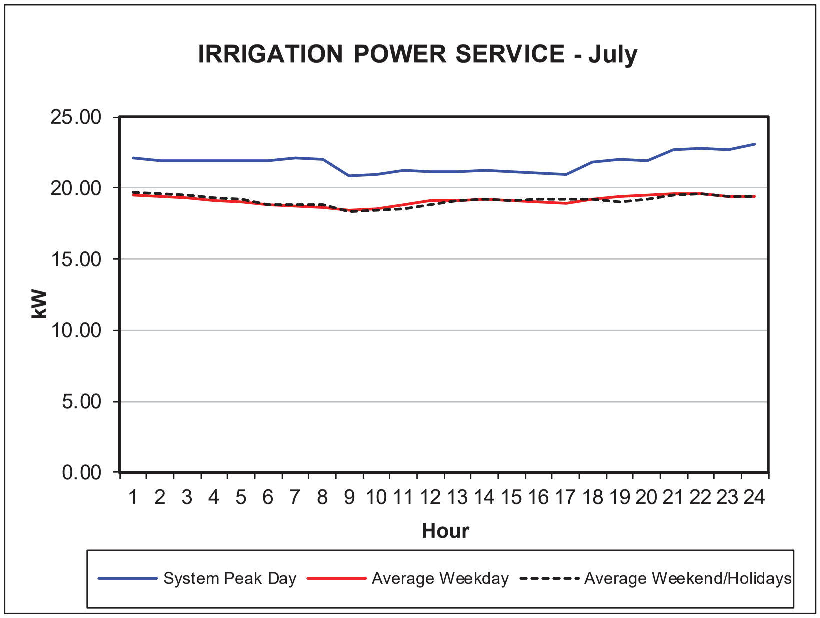


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.7

Jul-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	22.0794	19.4724	19.6678
2	21.9464	19.3973	19.6054
3	21.8652	19.3241	19.4816
4	21.8709	19.1248	19.3040
5	21.8899	18.9729	19.1984
6	21.9213	18.7820	18.8672
7	22.0992	18.7416	18.8542
8	21.9702	18.6682	18.8416
9	20.8148	18.4018	18.3776
10	20.9275	18.5009	18.4576
11	21.2524	18.8681	18.5472
12	21.1025	19.0772	18.8520
13	21.1208	19.0743	19.0818
14	21.2676	19.1640	19.2269
15	21.1448	19.1014	19.1187
16	21.0287	19.0546	19.2182
17	20.8993	18.9235	19.2397
18	21.8297	19.2201	19.2002
19	21.9968	19.3861	18.9914
20	21.9543	19.4874	19.2530
21	22.6641	19.6344	19.4553
22	22.8136	19.6184	19.5646
23	22.7113	19.4353	19.4097
24	23.0616	19.4230	19.3836

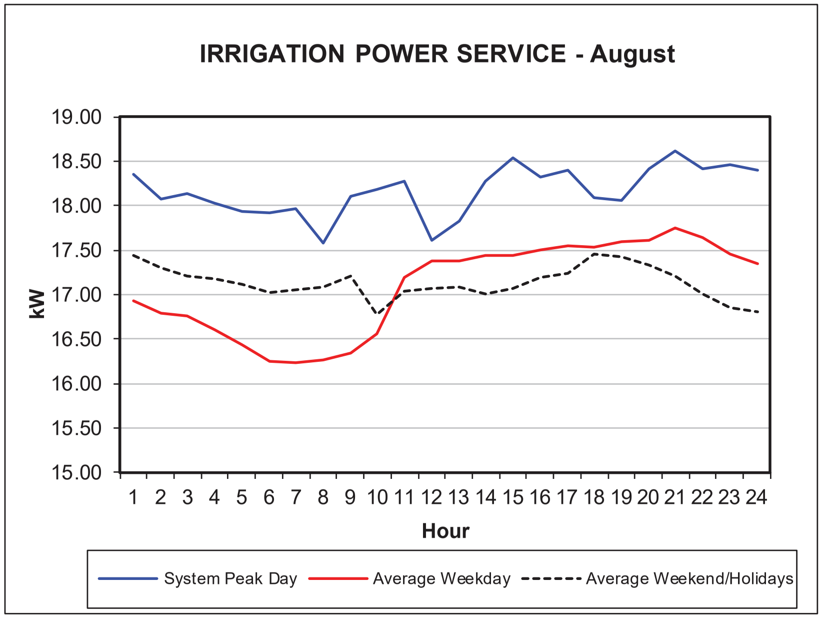


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.8

Aug-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18.3477	16.9302	17.4453
2	18.0664	16.7965	17.2940
3	18.1303	16.7584	17.2015
4	18.0189	16.5995	17.1716
5	17.9290	16.4413	17.1160
6	17.9232	16.2443	17.0189
7	17.9610	16.2304	17.0465
8	17.5741	16.2658	17.0837
9	18.1089	16.3413	17.2000
10	18.1888	16.5593	16.7822
11	18.2694	17.1890	17.0296
12	17.6088	17.3839	17.0632
13	17.8295	17.3781	17.0849
14	18.2697	17.4363	16.9997
15	18.5357	17.4383	17.0615
16	18.3144	17.5018	17.1962
17	18.4028	17.5451	17.2367
18	18.0863	17.5292	17.4594
19	18.0508	17.5876	17.4168
20	18.4081	17.6056	17.3255
21	18.6215	17.7408	17.2129
22	18.4124	17.6443	17.0078
23	18.4652	17.4482	16.8453
24	18.3944	17.3449	16.8110

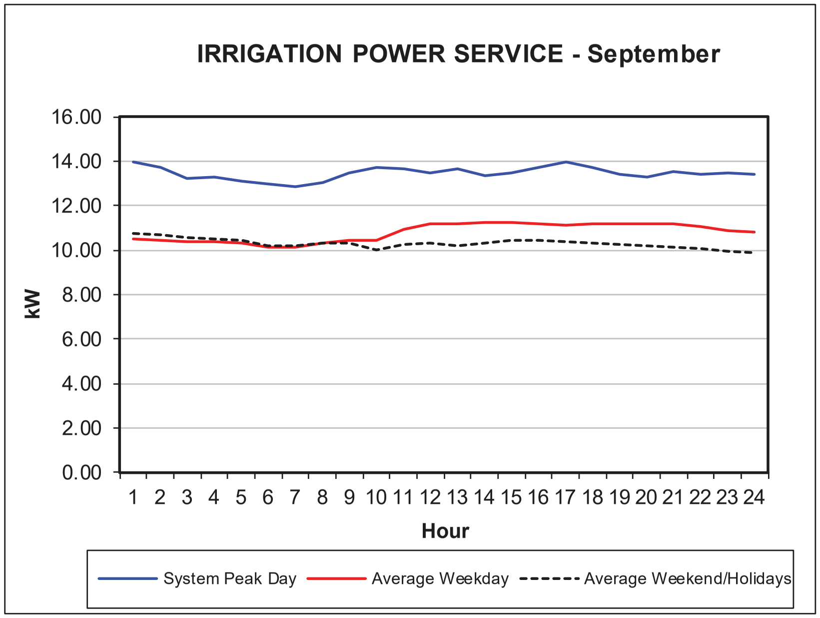


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.9

Sep-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13.9445	10.5278	10.7741
2	13.6994	10.4253	10.6738
3	13.1888	10.3792	10.5823
4	13.2809	10.3451	10.5230
5	13.1260	10.2856	10.4216
6	12.9659	10.1407	10.1616
7	12.8186	10.1129	10.1679
8	13.0093	10.2837	10.2844
9	13.4413	10.4637	10.2830
10	13.6890	10.4333	9.9752
11	13.6677	10.9112	10.2709
12	13.4960	11.2024	10.2951
13	13.6511	11.2063	10.2049
14	13.3733	11.2168	10.2842
15	13.4870	11.2259	10.4497
16	13.7382	11.2023	10.4312
17	13.9408	11.1472	10.3716
18	13.7237	11.1547	10.3386
19	13.4084	11.1883	10.2732
20	13.2855	11.1680	10.2170
21	13.5150	11.1881	10.1167
22	13.4156	11.0562	10.0805
23	13.4827	10.8975	9.9559
24	13.3972	10.8343	9.8881

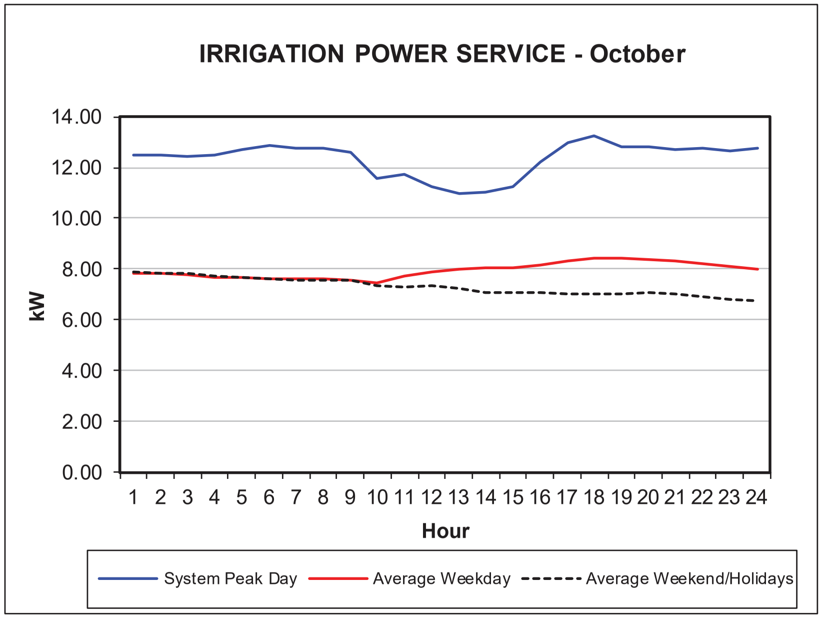


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.10

Oct-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.5090	7.8428	7.8963
2	12.4828	7.8309	7.8237
3	12.4059	7.7701	7.8193
4	12.4875	7.6792	7.7073
5	12.7276	7.6692	7.6574
6	12.8601	7.6164	7.6428
7	12.7525	7.6061	7.5744
8	12.7397	7.6041	7.5841
9	12.6069	7.5401	7.5373
10	11.5673	7.4467	7.3359
11	11.7097	7.7119	7.2954
12	11.2585	7.8853	7.3280
13	10.9777	8.0123	7.2427
14	11.0242	8.0379	7.0760
15	11.2311	8.0420	7.0506
16	12.2366	8.1493	7.0678
17	12.9679	8.3457	7.0201
18	13.2486	8.4457	7.0179
19	12.7918	8.4243	7.0060
20	12.8058	8.3972	7.1021
21	12.7023	8.3273	7.0130
22	12.7461	8.1934	6.9043
23	12.6624	8.1041	6.7869
24	12.7429	8.0051	6.7773

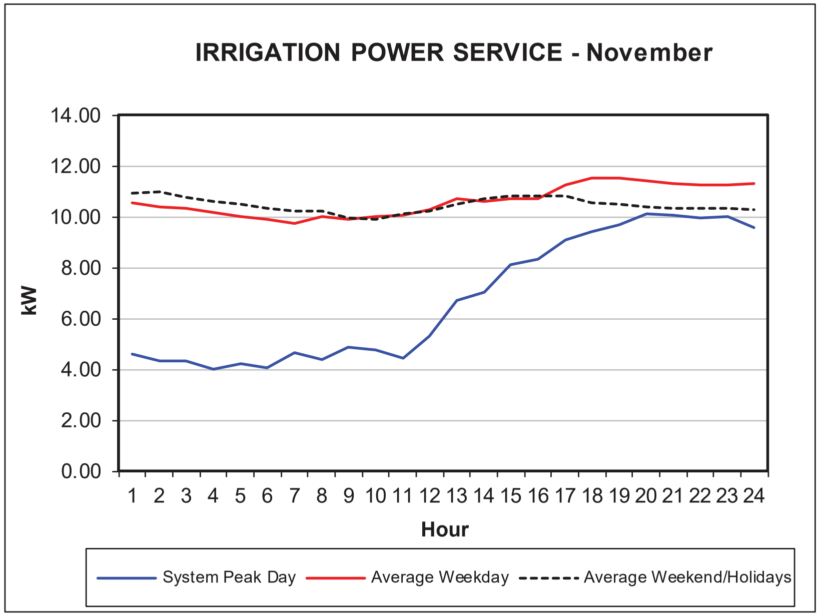


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.11

Nov-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4.5916	10.5568	10.9535
2	4.3056	10.3701	10.9669
3	4.3385	10.3477	10.7783
4	4.0207	10.1715	10.6240
5	4.2027	10.0327	10.4712
6	4.0359	9.8890	10.3437
7	4.6613	9.7372	10.2365
8	4.3847	10.0239	10.2501
9	4.8458	9.8792	9.9498
10	4.7728	9.9861	9.9047
11	4.4560	10.0552	10.1169
12	5.2757	10.3036	10.2313
13	6.7160	10.7115	10.5153
14	7.0172	10.5841	10.7234
15	8.0962	10.7069	10.8329
16	8.3568	10.7219	10.8220
17	9.0985	11.2598	10.8198
18	9.4001	11.5312	10.5680
19	9.6902	11.4985	10.4715
20	10.1376	11.3978	10.4065
21	10.0440	11.2902	10.3404
22	9.9716	11.2655	10.3526
23	10.0013	11.2482	10.3311
24	9.5553	11.2845	10.2783

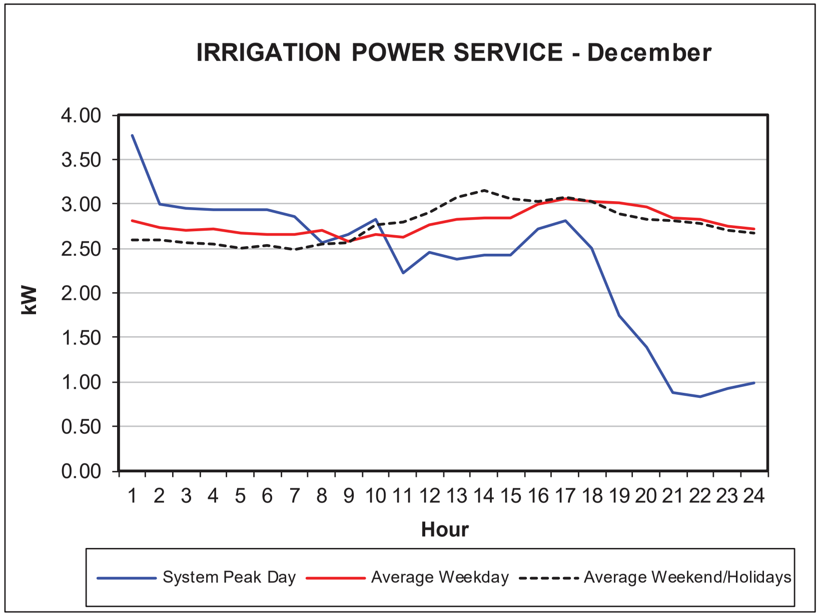


Southwestern Public Service Company
Hourly Load Profiles

TABLE E-10.12

Dec-20

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3.7774	2.8151	2.5957
2	2.9938	2.7287	2.5916
3	2.9546	2.7116	2.5612
4	2.9380	2.7173	2.5531
5	2.9404	2.6686	2.5036
6	2.9419	2.6635	2.5279
7	2.8632	2.6580	2.4812
8	2.5682	2.7044	2.5435
9	2.6647	2.5790	2.5667
10	2.8341	2.6579	2.7597
11	2.2310	2.6243	2.7949
12	2.4620	2.7716	2.9065
13	2.3820	2.8363	3.0821
14	2.4298	2.8500	3.1478
15	2.4289	2.8403	3.0596
16	2.7271	3.0028	3.0258
17	2.8086	3.0593	3.0831
18	2.5013	3.0236	3.0267
19	1.7400	3.0184	2.8956
20	1.3990	2.9629	2.8249
21	0.8814	2.8484	2.8074
22	0.8367	2.8234	2.7861
23	0.9350	2.7564	2.7037
24	0.9883	2.7185	2.6775


IRRIGATION POWER SERVICE - December

Southwestern Public Service Company
Econometric Model Parameters

The parameters associated with SPS's econometric forecasting models are provided in the following tables:

- Table F-1 through F-12 – Retail Energy Sales – Residential;
- Table F-13 through F-27 – Retail Energy Sales - Commercial and Industrial;
- Table F-28 through F-33 – Retail Energy Sales - Street Lighting;
- Table F-34 through F-39 – Retail Energy Sales - Other Public Authority;
- Table F-40 through F-57 – Retail Customers;
- Table F-58 through F-72 – Wholesale Energy Sales;
- Table F-73 through F-75 – Coincident Peak Demand – Retail; and
- Table F-76 through F-81 – Probability Distribution.

Table F-1: Retail Sales - New Mexico Residential Service

Retail Sales - New Mexico Residential Service

Dependent Variable: S_ResService_NM

Method: Least Squares

Sample: 2003M01 2020M12

Included observations: 216

S_ResService_NM = C(1)*CYPperHH_NM + C(2)*(Jan*HDD65B_ROS*C_ResService_NM) + C(3)*(Feb*HDD65B_ROS*C_ResService_NM) + C(4)*Mar*HDD65B_ROS*C_ResService_NM) + +C(5)*(Dec*HDD65B_ROS*C_ResService_NM) + C(6)*(May*CDD65B_ROS*C_ResService_NM) + C(7)*(Jun*CDD65B_ROS*C_ResService_NM) + C(8)*(Jul*CDD65B_ROS*C_ResService_NM) + C(9)*(Aug*CDD65B_ROS*C_ResService_NM) + C(10)*(Sep*CDD65B_ROS*C_ResService_NM) + C(11)*(Oct*CDD65B_ROS*C_ResService_NM) + C(12)*Bin0706 + C(13)*StructuralChange2 + C(14)*Expr1 +[SAR(1)=C(15)] + [SMA(1)=C(16)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	258.227808	7.588402	34.029	0.00%
C(2)	0.000699	0.000056	12.474	0.00%
C(3)	0.000494	0.000067	7.432	0.00%
C(4)	0.000506	0.000068	7.455	0.00%
C(5)	0.000556	0.000057	9.692	0.00%
C(6)	0.000618	0.000150	4.114	0.01%
C(7)	0.000994	0.000068	14.654	0.00%
C(8)	0.001092	0.000053	20.514	0.00%
C(9)	0.001117	0.000051	21.848	0.00%
C(10)	0.000954	0.000063	15.147	0.00%
C(11)	0.000979	0.000109	8.942	0.00%
C(12)	-3870.867065	2130.500111	-1.817	7.08%
C(13)	1386.430785	542.704447	2.555	1.14%
C(14)	-4425.837334	2197.523057	-2.014	4.54%
C(15)	0.887336	0.032295	27.476	0.00%
C(16)	-0.696677	0.067086	-10.385	0.00%

Table F-2: Retail Sales - New Mexico Residential Service – Regression Statistics

Model Statistics	
Adjusted Observations	204
R-Squared	0.968
Adjusted R-Squared	0.966
AIC	15.532
BIC	15.792
Log-Likelihood	-1,857.73
Model Sum of Squares	29,657,987,743.69
Sum of Squared Errors	970,485,689.27
Std. Error of Regression	2,272.04
Durbin-Watson Statistic	1.654
Mean dependent var	46,836.47
StdDev dependent var	12,223.57

Table F-3: Retail Sales - New Mexico Residential Service – Definitions

Retail Sales - New Mexico Residential Service

Variable Name	Definition
S_ResSvc_NM	Residential Service sales in New Mexico
CYPperHH_NM_MA12	12 Month Moving Average of Real personal income per household in New Mexico service area
H65_bill_ResSvc_NM_Jan	Heating degree days (January) multiplied by customers
H65_bill_ResSvc_NM_Feb	Heating degree days (February) multiplied by customers
H65_bill_ResSvc_NM_Mar	Heating degree days (March) multiplied by customers
H65_bill_ResSvc_NM_Dec	Heating degree days (December) multiplied by customers
C65_bill_ResSvc_NM_May	Cooling degree days (May) multiplied by customers
C65_bill_ResSvc_NM_Jun	Cooling degree days (June) multiplied by customers
C65_bill_ResSvc_NM_Jul	Cooling degree days (July) multiplied by customers
C65_bill_ResSvc_NM_Aug	Cooling degree days (August) multiplied by customers
C65_bill_ResSvc_NM_Sep	Cooling degree days (September) multiplied by customers
C65_bill_ResSvc_NM_Oct	Cooling degree days (October) multiplied by customers
Bin0706	Binary variable for July 2006=1, otherwise =0
StructuralChange2	Binary variable for (January or greater)=1 and 2018=1, otherwise =0
Expr1	Binary variable for June 2019=1, otherwise =0
SAR(1)	First-order Seasonal Autoregressive term
SMA(1)	First-order Seasonal Moving Average term

Table F-4: Retail Sales – New Mexico Residential Space Heating Service

Retail Sales - New Mexico Residential Space Heat Service

Dependent Variable: S_ResSpaceHeat_NM				
Method: Least Squares				
Sample: 2010M01 2020M12				
Included observations: 132				
S_ResSpaceHeat_NM = C(1)*Trend2014 +C(2)*(Jan*HDD65B_ROS*C_ResSpaceHeat_NM) + C(3)*(Feb*HDD65B_ROS*C_ResSpaceHeat_NM) + C(4)*(Mar*HDD65B_ROS*C_ResSpaceHeat_NM) + C(5)*(Nov*HDD65B_ROS*C_ResSpaceHeat_NM) + C(6)*(Dec*HDD65B_ROS*C_ResSpaceHeat_NM) + C(7)*(Jun*CDD65B_ROS*C_ResSpaceHeat_NM) + C(8)*(Jul*CDD65B_ROS*C_ResSpaceHeat_NM) + C(9)*(Aug*CDD65B_ROS*C_ResSpaceHeat_NM) + C(10)*(Sep*CDD65B_ROS*C_ResSpaceHeat_NM) + C(11)*HolidayVariable + C(12)*BILLINGDAYS + [AR(1)=C(13)] + [MA(1)=C(14)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-24.561494	12.078	-2.034	4.43%
C(2)	0.001321	0.000	38.694	0.00%
C(3)	0.001214	0.000	28.062	0.00%
C(4)	0.001003	0.000	19.242	0.00%
C(5)	0.001192	0.000	3.515	0.06%
C(6)	0.001233	0.000	8.881	0.00%
C(7)	0.000717	0.000	10.685	0.00%
C(8)	0.000974	0.000	20.557	0.00%
C(9)	0.001070	0.000	23.918	0.00%
C(10)	0.000782	0.000	13.505	0.00%
C(11)	-7982.155992	2373.515	-3.363	0.11%
C(12)	1036.796183	18.926	54.782	0.00%
C(13)	0.583023	0.220	2.646	0.93%
C(14)	-0.285	0.259	-1.101	27.31%

Table F-5: Retail Sales - New Mexico Residential Space Heating Service – Regression Statistics

Model Statistics	
Adjusted Observations	131
R-Squared	0.962
Adjusted R-Squared	0.958
AIC	15.578
BIC	15.885
Log-Likelihood	-1,192.23
Model Sum of Squares	15,644,886,965.30
Sum of Squared Errors	616,295,772.17
Std. Error of Regression	2,295.10
Durbin-Watson Statistic	1.961
Mean dependent var	42,037.66
StdDev dependent var	11,347.34

Table F-6: Retail Sales - New Mexico Residential Space Heating Service – Definitions

Retail Sales - New Mexico Residential Space Heat Service

Variable Name	Definition
S_ResSpaceHeat_NM	Residential Space Heating Service sales in New Mexico
Trend2014	Trend Variable beginning in January 2014
H65_bill_ResSpHt_NM_Jan	Heating degree days (January) multiplied by customers
H65_bill_ResSpHt_NM_Feb	Heating degree days (February) multiplied by customers
H65_bill_ResSpHt_NM_Mar	Heating degree days (March) multiplied by customers
H65_bill_ResSpHt_NM_Nov	Heating degree days (November) multiplied by customers
H65_bill_ResSpHt_NM_Dec	Heating degree days (December) multiplied by customers
C65_bill_ResSpHt_NM_Jun	Cooling degree days (June) multiplied by customers
C65_bill_ResSpHt_NM_Jul	Cooling degree days (July) multiplied by customers
C65_bill_ResSpHt_NM_Aug	Cooling degree days (August) multiplied by customers
C65_bill_ResSpHt_NM_Sep	Cooling degree days (September) multiplied by customers
HolidayVariable	Binary variable for November and December=1, otherwise =0
BILLINGDAYS	Number of scheduled billing day per revenue month
AR(1)	First-order autoregressive term
MA(1)	First-order Moving Average term

Table F-7: Retail Sales – Texas Residential Service

Retail Sales - Texas Residential Service

Dependent Variable: S_ResService_TX

Method: Least Squares

Sample: 2000M01 2020M12

Included observations: 252

S_ResService_TX = C(1)*CYPperHH_TX + C(2)*(Jan*HDD65B_PAN*TX_Res_Cust) +
C(3)*(Feb*HDD65B_PAN*TX_Res_Cust) + C(4)*Mar*HDD65B_PAN*TX_Res_Cust) +
C(5)*Apr*HDD65B_PAN*TX_Res_Cust) + C(6)*(Nov*HDD65B_PAN*TX_Res_Cust) +
C(7)*(Dec*HDD65B_PAN*TX_Res_Cust) + C(8)*(May*CDD65B_PAN*TX_Res_Cust) +
C(9)*(Jun*CDD65B_PAN*TX_Res_Cust) + C(10)*(Jul*CDD65B_PAN*TX_Res_Cust) +
C(11)*(Aug*CDD65B_PAN*TX_Res_Cust) + C(12)*(Sep*CDD65B_PAN*TX_Res_Cust) +
C(13)*(Oct*CDD65B_PAN*TX_Res_Cust) + C(14)*BILLINGDAYS + [AR(1)=C(15)] + [AR(2)=C(16)] + [MA(1)=C(17)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	272.248	84.169	3.23455	0.00141
C(2)	0.000582	0.000	20.58002	0.00000
C(3)	0.000453	0.000	14.26200	0.00000
C(4)	0.000405	0.000	10.41985	0.00000
C(5)	0.000241	0.000	3.58883	0.00042
C(6)	0.000307	0.000	3.94370	0.00011
C(7)	0.000457	0.000	12.39506	0.00000
C(8)	0.000968	0.000	3.40971	0.00078
C(9)	0.001358	0.000	15.79350	0.00000
C(10)	0.001458	0.000	27.01273	0.00000
C(11)	0.001485	0.000	30.60569	0.00000
C(12)	0.001	0.000	21.53475	0.00000
C(13)	0.001	0.000	8.48935	0.00000
C(14)	3315.763	338.895	9.78405	0.00000
C(15)	1.091	0.064	17.01030	0.00000
C(16)	-0.132	0.061	-2.15576	0.03212
C(17)	-1.049	0.029	-36.42447	0.00000

Table F-8: Retail Sales – Texas Residential Service – Regression Statistics

Retail Sales - Texas Residential Service

Model Statistics	
Adjusted Observations	250
R-Squared	0.940
Adjusted R-Squared	0.935
AIC	18.843
BIC	19.083
Log-Likelihood	-2,693.14
Model Sum of Squares	517,202,104,321.40
Sum of Squared Errors	33,296,840,096.46
Std. Error of Regression	11,954.28
Durbin-Watson Statistic	2.061
Mean dependent var	192,024.56
StdDev dependent var	46,930.27

Table F-9: Retail Sales – Texas Residential Service – Definitions

Retail Sales - Texas Residential Service

Variable Name	Definition
S_ResService_TX	Residential Service sales in Texas
CYP_HH_TX	Real personal income per household in Texas service area
H65_bill_Res_TX_Jan	Heating degree days (January) multiplied by customers
H65_bill_Res_TX_Feb	Heating degree days (February) multiplied by customers
H65_bill_Res_TX_Mar	Heating degree days (March) multiplied by customers
H65_bill_Res_TX_Apr	Heating degree days (April) multiplied by customers
H65_bill_Res_TX_Nov	Heating degree days (November) multiplied by customers
H65_bill_Res_TX_Dec	Heating degree days (December) multiplied by customers
C65_bill_Res_TX_May	Cooling degree days (May) multiplied by customers
C65_bill_Res_TX_Jun	Cooling degree days (June) multiplied by customers
C65_bill_Res_TX_Jul	Cooling degree days (July) multiplied by customers
C65_bill_Res_TX_Aug	Cooling degree days (August) multiplied by customers
C65_bill_Res_TX_Sep	Cooling degree days (September) multiplied by customers
C65_bill_Res_TX_Oct	Cooling degree days (October) multiplied by customers
BILLINGDAYS	Number of scheduled billing day per revenue month
AR(1)	First-order autoregressive term
AR(2)	Second-order autoregressive term
MA(1)	First-order Moving Average term

Table F-13: Retail Sales – New Mexico Small Commercial and Industrial Service

Retail Sales - New Mexico Small Commercial and Industrial

Dependent Variable: S_SMCI_NM
Method: Least Squares
Sample: 2006M01 2020M12
Included observations: 180

S_SMCI_NM = C(1)*EE_NM + C(2)*(Jan*HDD65B_ROS*CUST_SMCI_NM) + C(3)*(Feb) + C(4)*(Jun*CDD65B_ROS*CUST_SMCI_NM) + C(5)*(Jul*CDD65B_ROS*CUST_SMCI_NM) + C(6)*(Aug*CDD65B_ROS*CUST_SMCI_NM) + C(7)*(Sep*CDD65B_ROS*CUST_SMCI_NM) + C(8)*(Nov*HDD65B_ROS*CUST_SMCI_NM + Dec*HDD65B*CUST_SMCI_NM) + C(9)*HolidayVariable + C(10)*CustomerShift2016 + C(11)*BIN0707 + C(12)*SalesShift_SMCI_2018 + C(13)*TrendVar

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	698.868	41.802	16.71844	0.00000
C(2)	0.001	0.000	4.17538	0.00005
C(3)	-14962.694	2097.619	-7.13318	0.00000
C(4)	0.002	0.000	6.99881	0.00000
C(5)	0.002	0.000	11.09063	0.00000
C(6)	0.002	0.000	11.86464	0.00000
C(7)	0.002	0.000	5.93449	0.00000
C(8)	0.001	0.000	2.22387	0.02757
C(9)	-17337.954	3609.071	-4.80399	0.00000
C(10)	6471.271	1680.583	3.85061	0.00018
C(11)	18779.816	7139.522	2.63040	0.00937
C(12)	13353.742	1741.182	7.66935	0.00000
C(13)	138.996	17.428	7.97551	0.00000

Table F-14: Retail Sales - New Mexico Small Commercial and Industrial – Regression Statistics

Retail Sales - New Mexico Small Commercial and Industrial

Model Statistics	
Adjusted Observations	180
R-Squared	0.894
Adjusted R-Squared	0.887
AIC	17.926
BIC	18.156
Log-Likelihood	-1,855.72
Model Sum of Squares	80,319,787,568.79
Sum of Squared Errors	9,496,279,717.91
Std. Error of Regression	7,540.82
Durbin-Watson Statistic	2.188
Mean dependent var	124,911.84
StdDev dependent var	22,400.13

Table F-15: Retail Sales - New Mexico Small Commercial and Industrial Service – Definitions

Retail Sales - New Mexico Small Commercial and Industrial

Variable Name	Definition
S_SMCI_NM	Small Commercial & Industrial sales in New Mexico
CYP_NM	Real Personal Income for New Mexico Service Territory
H65_bill_SMCI_NM_Jan	Heating degree days (January) multiplied by customers
Feb	Binary variable for February, otherwise =0
C65_bill_SMCI_NM_Jun	Cooling degree days (June) multiplied by customers
C65_bill_SMCI_NM_Jul	Cooling degree days (July) multiplied by customers
C65_bill_SMCI_NM_Aug	Cooling degree days (August) multiplied by customers
C65_bill_SMCI_NM_Sep	Cooling degree days (September) multiplied by customers
H65_bill_SMCI_NM_NovDec	Heating degree days (November and December) multiplied by customers
HolidayVariable	Binary variable for November and December=1, otherwise =0
CustomerShift2016	Shift effective September 2016 forward=1, prior values =0
Bin0707	Binary variable for July 2007=1, otherwise =0
SalesShift_SMCI_2018	Binary variable for (greater than August=1) and Year=2018, otherwise =0
TrendVar	Increasing linear trend variable starting January 1990

Table F-16: Retail Sales – Texas Small Commercial and Industrial Service

Retail Sales - Texas Small Commercial and Industrial				
Dependent Variable: S_SMCI_TX				
Method: Least Squares				
Sample: 2010M01 2020M12				
Included observations: 132				
C(3)*(JUN*CDD65B_PAN*CUST_SMCI_TX) + C(4)*(JUL*CDD65B_PAN*CUST_SMCI_TX) + C(5)*(AUG*CDD65B_PAN*CUST_SMCI_TX) + C(6)*(SEP*CDD65B_PAN*CUST_SMCI_TX) + C(7) * (OCT*CDD65B_PAN*CUST_SMCI_TX) + C(8) * (JAN*HDD65B_PAN*CUST_SMCI_TX) + C(9) * (NOV*HDD65B_PAN*CUST_SMCI_TX+DEC*HDD65B_PAN*CUST_SMCI_TX) + C(10)*Bin1016 + C(11)*Bin0318 + C(12)*Bin0112 + C(13)*Bin0413 + C(14)*Bin1118 + C(15)*Bin1017 + C(16)*Nov + C(17)*TrendVar + C(18)*COVID_19_Impact_Mar2020 + [SAR(1) = C(19)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	278606.864	11314.817	24.62319	0.00000
C(2)	0.006	0.001	6.08810	0.00000
C(3)	0.003	0.000	11.10758	0.00000
C(4)	0.004	0.000	19.69236	0.00000
C(5)	0.004	0.000	24.70917	0.00000
C(6)	0.004	0.000	16.74412	0.00000
C(7)	0.004	0.001	7.06419	0.00000
C(8)	0.001	0.000	10.54065	0.00000
C(9)	0.001	0.000	8.00367	0.00000
C(10)	-32840.140	10539.616	-3.11588	0.00239
C(11)	29660.416	10128.482	2.92842	0.00421
C(12)	-35799.985	10328.744	-3.46605	0.00078
C(13)	25592.401	10081.348	2.53859	0.01265
C(14)	-15321.610	10347.931	-1.48064	0.14182
C(15)	-21865.710	10508.134	-2.08084	0.03998
C(16)	-17666.276	4345.521	-4.06540	0.00010
C(17)	-151.284	36.143	-4.18574	0.00006
C(18)	-14581.223	4764.283	-3.06053	0.00283
C(19)	0.142	0.081	1.74867	0.08339

Table F-17: Retail Sales - Texas Small Commercial and Industrial Service – Regression Statistics

Retail Sales - Texas Small Commercial and Industrial

Model Statistics	
Adjusted Observations	120
R-Squared	0.929
Adjusted R-Squared	0.917
AIC	18.680
BIC	19.121
Log-Likelihood	-1,272.08
Model Sum of Squares	148,926,268,592.65
Sum of Squared Errors	11,332,173,119.58
Std. Error of Regression	10,592.44
Durbin-Watson Statistic	1.898
Mean dependent var	267,608.51
StdDev dependent var	37,184.23

Table F-18: Retail Sales - Texas Small Commercial and Industrial Service – Definitions

Retail Sales - Texas Small Commercial and Industrial

Variable Name	Definition
S_SMCI_TX	Small Commercial and Industrial Service sales in Texas
CONST	Constant variable
C65_bill_SMCI_TX_May	Cooling degree days (May) multiplied by customers
C65_bill_SMCI_TX_Jun	Cooling degree days (June) multiplied by customers
C65_bill_SMCI_TX_Jul	Cooling degree days (July) multiplied by customers
C65_bill_SMCI_TX_Aug	Cooling degree days (August) multiplied by customers
C65_bill_SMCI_TX_Sep	Cooling degree days (September) multiplied by customers
C65_bill_SMCI_TX_Oct	Cooling degree days (October) multiplied by customers
H65_bill_SMCI_TX_Jan	Heating degree days (January) multiplied by customers
H65_bill_SMCI_TX_Aggregate	Heating degree days (November and December) multiplied by customers
Bin1016	Binary variable for October 2016=1, otherwise=0
Bin0318	Binary variable for March 2018=1, otherwise=0
Bin0112	Binary variable for January 2012=1, otherwise=0
Bin0413	Binary variable for April 2013=1, otherwise=0
Bin1118	Binary variable for November 2018=1, otherwise=0
Bin1017	Binary variable for October 2017=1, otherwise=0
Nov	Seasonal binary variable, November=1, otherwise =0
TrendVar	Trend Variable starting January 1990
COVID_19_Impact_Mar2020	Binary variable to account for Covid impacts; from March 2020 to June 2024
SAR(1)	First-order Seasonal Autoregressive term

Table F-19: Retail Sales – New Mexico Large Commercial and Industrial Service

Retail Sales - New Mexico Large Commercial and Industrial

Dependent Variable: S_LGCI_NM

Method: Least Squares

Sample: 2006M01 2020M12

Included observations: 180

S_LGCI_NM = C(1)*NM_Large_Adj + C(2)*BIN0309 + C(3)*BIN0709 + C(4)*BIN0110 + C(5)*BIN0115 + C(6)*BIN0419 + C(7)*BinJan + C(8)*BinFeb + C(9)*BinMar + C(10)*BinAug + C(11)*BinSep + C(12)*IPSG211A3 + C(13)*LGCItrend + [MA(1) = C(14)] + [MA(2) = C(15)] + [MA(3) = C(16)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	37907.032	4734.167	8.00712	0.00000
C(2)	-22518.913	10212.811	-2.20497	0.02884
C(3)	28420.556	10054.518	2.82665	0.00529
C(4)	-23618.678	10066.448	-2.34628	0.02015
C(5)	27226.838	9843.612	2.76594	0.00633
C(6)	29531.108	9979.964	2.95904	0.00355
C(7)	7271.341	3234.601	2.24799	0.02590
C(8)	-13022.207	3141.793	-4.14483	0.00006
C(9)	-7421.001	3277.558	-2.26419	0.02486
C(10)	5208.536	2822.913	1.84509	0.06683
C(11)	8752.749	2773.290	3.15609	0.00191
C(12)	1652.904	26.410	62.58671	0.00000
C(13)	158494.744	22904.190	6.91990	0.00000
C(14)	0.539	0.081	6.63776	0.00000
C(15)	0.574	0.080	7.16925	0.00000
C(16)	0.208	0.084	2.45877	0.01497

Table F-20: Retail Sales - New Mexico Large Commercial and Industrial Service – Regression Statistics

Retail Sales - New Mexico Large Commercial and Industrial

Model Statistics	
Adjusted Observations	180
R-Squared	0.950
Adjusted R-Squared	0.946
AIC	18.844
BIC	19.127
Log-Likelihood	-1,935.34
Model Sum of Squares	441,255,189,012.08
Sum of Squared Errors	23,002,066,617.89
Std. Error of Regression	11,842.99
Durbin-Watson Statistic	1.853
Mean dependent var	185,863.01
StdDev dependent var	50,927.56

Table F-21: Retail Sales - New Mexico Large Commercial and Industrial Service – Definitions

Retail Sales - New Mexico Large Commercial and Industrial

Variable Name	Definition
S_LGCI_NM	Large Commercial & Industrial sales in New Mexico
NM_Large_Adj	Shift effective January 2016 forward=1, prior values =0
Bin0309	Binary for March 2009=1, otherwise =0
Bin0709	Binary for July 2009=1, otherwise =0
Bin0110	Binary for January 2010=1, otherwise =0
Bin1115	Binary for November 2015=1, otherwise =0
Bin0419	Binary for April 2019=1, otherwise =0
Jan	Binary variable for
Feb	Binary variable for
Mar	Binary variable for March, otherwise =0
Aug	Binary variable for August, otherwise =0
Sep	Binary variable for September, otherwise =0
IPSG211A3	Oil and gas extraction index
LGCItrend	Trend Variable for Large Commercial sales
MA(1)	First-order Moving Average term
MA(2)	Second-order Moving Average term
MA(3)	Third-order Moving Average term

Table F-22: Retail Sales – Texas Large Commercial and Industrial Service

Retail Sales - Texas Large Commercial and Industrial-Other

Dependent Variable: S_LGCI_TX

Method: Least Squares

Sample: 2009M01 2020M12

Included observations: 144

S_LGCI_TX = C(1)*CONST + C(2)*GDPR_Log + C(3)*BINFEB + C(4)*BINMAR + C(5)*BINMAY + C(6)*BINAUG + C(7)*BINSEP + C(8)*BINNOV+ C(9)*BIN0612 + C(10)*BIN0712+ C(11)*BIN1212 + C(12)*BIN0418 + C(13)*BIN0311 + C(14)*BIN0211+ C(15)*Trend2016 + [AR(1)=C(16)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-2458759.474	296377.849	-8.296	0.00%
C(2)	289386.039	30537.950	9.476	0.00%
C(3)	-10586.330	3128.473	-3.384	0.10%
C(4)	-21341.319	3136.482	-6.804	0.00%
C(5)	-13130.426	2839.929	-4.624	0.00%
C(6)	16731.558	3055.226	5.476	0.00%
C(7)	21698.292	3006.075	7.218	0.00%
C(8)	-5866.161	2811.833	-2.086	3.90%
C(9)	-54085.296	10062.376	-5.375	0.00%
C(10)	52402.072	10074.800	5.201	0.00%
C(11)	-34787.911	9586.807	-3.629	0.04%
C(12)	-24657.477	9605.347	-2.567	1.14%
C(13)	-19270.604	10422.801	-1.849	6.68%
C(14)	-21997.955	10419.888	-2.111	3.67%
C(15)	-5467.741	619.813	-8.822	0.00%
C(16)	0.351	0.085	4.138	0.01%

Table F-23: Retail Sales - Texas Large Commercial and Industrial Service – Regression Statistics

Retail Sales - Texas Large Commercial and Industrial-Other

Model Statistics	
Adjusted Observations	143
R-Squared	0.814
Adjusted R-Squared	0.792
AIC	18.533
BIC	18.864
Log-Likelihood	-1,512.016
Model Sum of Squares	55,942,867,847.988
Sum of Squared Errors	12,791,492,626.85
Std. Error of Regression	10,035.96
Durbin-Watson Statistic	2.01
Mean dependent var	346,535.08
StdDev dependent var	21,972.11

Table F-24: Retail Sales - Texas Large Commercial and Industrial Service – Definitions

Retail Sales - Texas Large Commercial and Industrial-Other

Variable Name	Definition
S_LGCI_TX	Large Commercial and Industrial sales in Texas
CONST	Constant variable
GDPR_log	Log of Real Gross Domestic Product
Feb	Seasonal binary variable, February=1, otherwise =0
Mar	Seasonal binary variable, March=1, otherwise =1
May	Seasonal binary variable, May=1, otherwise =2
Aug	Seasonal binary variable, August=1, otherwise =3
Sep	Seasonal binary variable, September=1, otherwise =4
Nov	Seasonal binary variable, November=1, otherwise =5
Bin0612	Binary variable for June 2012=1, otherwise =0
Bin0712	Binary variable for July 2012=1, otherwise =0
Bin1212	Binary variable for December 2012=1, otherwise =0
Bin0418	Binary variable for April 2018=1, otherwise =0
Bin0311	Binary variable for March 2011=1, otherwise =0
Bin0211	Binary variable for February 2011=1, otherwise =0
Trend2016	Trend Variable starting January 2016
AR(1)	First-order Autoregressive term

Table F-25: Retail Sales – Texas Large Commercial and Industrial Service

Retail Sales - Texas Large Commercial and Industrial -OXY

Dependent Variable: S_LGCI_OXY_TX				
Method: Least Squares				
Sample: 2008M01 2020M12				
Included observations: 156				
S_LGCI_OXY_TX = C(1)*CONST + C(2)*TrendVar + C(3)*BINJAN + C(4)*BINFEB + C(5)*BINMAR + C(6)*BINAPR + C(7)*BINJUN + C(8)*BINAUG + C(9)*BINSEP + C(10)*BINNOV + C(11)*BIN1109 + C(12)*BIN01209+ [AR(1)=C(13)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	246382.660	17137.123	14.37713	0.00000
C(2)	179.641	56.829	3.16108	0.00193
C(3)	9853.029	2579.676	3.81948	0.00021
C(4)	11177.928	2975.604	3.75652	0.00026
C(5)	-14885.577	2942.820	-5.05827	0.00000
C(6)	12613.117	2445.664	5.15734	0.00000
C(7)	10621.026	1988.059	5.34241	0.00000
C(8)	9624.568	2266.373	4.24668	0.00004
C(9)	12766.292	2266.246	5.63323	0.00000
C(10)	6349.905	2068.502	3.06981	0.00257
C(11)	55862.193	8430.392	6.62629	0.00000
C(12)	54967.485	8292.680	6.62843	0.00000
C(13)	0.718	0.059	12.15785	0.00000

Table F-26: Retail Sales - Texas Large Commercial and Industrial Service – Regression Statistics

Retail Sales - Texas Large Commercial and Industrial -OXY

Model Statistics	
Adjusted Observations	155
R-Squared	0.762
Adjusted R-Squared	0.742
AIC	18.251
BIC	18.507
Log-Likelihood	-1,621.425
Model Sum of Squares	35,438,768,067.746
Sum of Squared Errors	11,066,203,471.03
Std. Error of Regression	8,827.85
Durbin-Watson Statistic	2.39
Mean dependent var	304,650.11
StdDev dependent var	17,555.17

Table F-27: Retail Sales - Texas Large Commercial and Industrial Service – Definitions

Retail Sales - Texas Large Commercial and Industrial -OXY

Variable Name	Definition
S_LGCI_OXY_TX	Large Commercial and Industrial sales in Texas - OXY
CONST	Constant variable
TrendVar	Trend Variable starting January 1990
Jan	Seasonal binary variable, January=1, otherwise =0
Feb	Seasonal binary variable, February=1, otherwise =0
Mar	Seasonal binary variable, March=1, otherwise =0
Apr	Seasonal binary variable, April=1, otherwise =0
Jun	Seasonal binary variable, June=1, otherwise =0
Aug	Seasonal binary variable, August=1, otherwise =0
Sep	Seasonal binary variable, September=1, otherwise =0
Nov	Seasonal binary variable, November=1, otherwise =0
Bin1109	Binary variable for November 2009=1, otherwise=0
Bin1209	Binary variable for December 2009=1, otherwise=0
AR(1)	First-order autoregressive term

Table F-28: Retail Sales – New Mexico Street Lighting

Retail Sales - New Mexico Street Lighting

Dependent Variable: S_STLIGHT_NM				
Method: Least Squares				
Sample: 2012M01 2020M12				
Included observations: 108				
S_STLIGHT_NM=C(1)*BINJAN+ C(2)*BINFEB + C(3)*BINMAR + C(4)*BINAPR + C(5)*BINMAY + C(6)*BINJUN + C(7)*BINJUL + C(8)*BINAUG + C(9)*BINSEP + C(10)*BINOCT + C(11)*BINNOV + C(12)*BINDEC + C(13)*SalesShift_StLt_2018 + C(14)*LEDConversionTrend + [AR(1)=C(15)] + [AR(2)=C(16)] + [AR(3)=C(17)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	1107.398	14.071	78.69864	0.00000
C(2)	1104.445	14.120	78.21975	0.00000
C(3)	1107.055	14.192	78.00692	0.00000
C(4)	1109.038	14.315	77.47113	0.00000
C(5)	1108.763	14.314	77.46046	0.00000
C(6)	1114.300	14.280	78.03051	0.00000
C(7)	1112.116	14.246	78.06673	0.00000
C(8)	1114.463	14.202	78.47189	0.00000
C(9)	1109.450	14.154	78.38639	0.00000
C(10)	1111.453	14.098	78.83797	0.00000
C(11)	1109.349	14.052	78.94602	0.00000
C(12)	1106.855	14.053	78.76467	0.00000
C(13)	-2.803	8.940	-0.31356	0.75461
C(14)	-17.200	4.895	-3.51354	0.00071
C(15)	1.267	0.105	12.02866	0.00000
C(16)	0.085	0.168	0.50432	0.61530
C(17)	-0.428	0.125	-3.42812	0.00093

Table F-29: Retail Sales - New Mexico Street Lighting – Regression Statistics

Retail Sales - New Mexico Street Lighting

Model Statistics	
Adjusted Observations	105
R-Squared	0.9784
Adjusted R-Squared	0.9744
AIC	4.661
BIC	5.090
Log-Likelihood	-376.679
Model Sum of Squares	363,249.711
Sum of Squared Errors	8,029.83
Std. Error of Regression	9.55
Durbin-Watson Statistic	2.14
Mean dependent var	1,086.72
StdDev dependent var	59.06

Table F-30: Retail Sales - New Mexico Street Lighting – Definitions

Retail Sales - New Mexico Street Lighting

Variable Name	Definition
C_StreetLight	Street Lighting Service sales in the New Mexico service area
Jan	Seasonal binary variable, January=1, otherwise =0
Feb	Seasonal binary variable, February=1, otherwise =0
Mar	Seasonal binary variable, March=1, otherwise =0
Apr	Seasonal binary variable, April=1, otherwise =0
May	Seasonal binary variable, May=1, otherwise =0
Jun	Seasonal binary variable, June=1, otherwise =0
Jul	Seasonal binary variable, July=1, otherwise =0
Aug	Seasonal binary variable, August=1, otherwise =0
Sep	Seasonal binary variable, September=1, otherwise =0
Oct	Seasonal binary variable, October=1, otherwise =0
Nov	Seasonal binary variable, November=1, otherwise =0
Dec	Seasonal binary variable, December=1, otherwise =0
SalesShift_StLt_2018	Binary variable for month>September and year 2018=1, otherwise =0
LEDConversionTrend	Binary variable starting April 2019 to December 2050
AR(1)	Autoregressive corrective term 1st period
AR(2)	Autoregressive corrective term 2nd period
AR(3)	Autoregressive corrective term 3nd period

Table F-31: Retail Sales - Texas Street Lighting

Dependent Variable: SL_UPC_TX

Method: Least Squares

Sample: 2011M05 2020M12

Included observations: 116

S_STREET_TX = C(1)* CONST + C(2)*Street_TXJun2019 + C(3)*LEDConversionTrend + [AR(1)=C(4)] +[MA(1)=C(5)] + [MA(2)=C(6)] +[MA(3)=C(7)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	29.062	0.251	115.87519	0.00000
C(2)	0.108	0.050	2.14012	0.03459
C(3)	-0.316	0.036	-8.70394	0.00000
C(4)	0.903	0.010	92.55278	0.00000
C(5)	1.116	0.091	12.30655	0.00000
C(6)	0.849	0.118	7.21741	0.00000
C(7)	0.399	0.092	4.32121	0.00004

Table F-32: Retail Sales - Texas Street Lighting – Regression Statistics

Retail Sales - Texas Street Lighting

Model Statistics	
Adjusted Observations	115
R-Squared	0.9982
Adjusted R-Squared	0.9981
AIC	-5.271
BIC	-5.104
Log-Likelihood	146.918
Model Sum of Squares	295.975
Sum of Squared Errors	0.52
Std. Error of Regression	0.07
Durbin-Watson Statistic	1.67
Mean dependent var	28.23
StdDev dependent var	1.70

Table F-33: Retail Sales - Texas Street Lighting – Definitions

Retail Sales - Texas Street Lighting

Variable Name	Definition
SL_UPC_TX	Street Lighting Use Per Customer Sales in Texas
CONST	Constant variable
Street_TXJun2019	Binary variable for month > March and year = 2019
LEDConversionTrend	Binary variable starting April 2019 to December 2050
AR(1)	Autoregressive corrective term 1st period
MA(1)	Moving Average term 1st period
MA(2)	First-order autoregressive term
MA(3)	First-order autoregressive term

Table F-34: Retail Sales – New Mexico Other Public Authority

Retail Sales - New Mexico Other Public Authority

Dependent Variable: S_MUNISCHOOL_NM

Method: Least Squares

Sample: 2010M01 2020M12

Included observations: 116

S_MUNISCHOOL_NM = C(1)*Constant + C(2)*(CDD65B_ROS*JUN) + C(3)*(CDD65B_ROS*JUL) + C(4)*(CDD65B_ROS*AUG) + C(5)*(CDD65B_ROS*SEP) + C(6)*BINOCT + C(7)*BIN0511 + C(8)*BIN0917+ C(9)*BIN0417 + C(10)*BIN1112 + C(11)*BIN1217 + C(12)*BIN0114 + C(13)*1016 + C(14)*OtherTrend + C(15)*Covid_19_Impact_Apr2020_School

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	10011.787	106.551	93.96279	0.00000
C(2)	3.949	0.713	5.54296	0.00000
C(3)	4.497	0.467	9.62879	0.00000
C(4)	5.680	0.442	12.85305	0.00000
C(5)	8.640	0.631	13.69441	0.00000
C(6)	3628.197	272.697	13.30486	0.00000
C(7)	2329.871	770.079	3.02550	0.00315
C(8)	-2456.074	794.129	-3.09279	0.00257
C(9)	-1555.409	770.079	-2.01980	0.04605
C(10)	2475.720	770.079	3.21489	0.00176
C(11)	-1994.451	770.079	-2.58993	0.01101
C(12)	2661.527	770.079	3.45617	0.00081
C(13)	-2515.607	804.861	-3.12552	0.00232
C(14)	-214.543	204.106	-1.05114	0.29570
C(15)	-1151.835	333.654	-3.45218	0.00082

Table F-35: Retail Sales - New Mexico Other Public Authority – Regression Statistics

Retail Sales - New Mexico Other Public Authority

Model Statistics	
Adjusted Observations	116
R-Squared	0.8322
Adjusted R-Squared	0.8089
AIC	13.394
BIC	13.750
Log-Likelihood	-926.438
Model Sum of Squares	291,350,515.972
Sum of Squared Errors	58,748,573.61
Std. Error of Regression	762.67
Durbin-Watson Statistic	2.02
Mean dependent var	11,121.55
StdDev dependent var	1,744.80

Table F-36: Retail Sales - New Mexico Other Public Authority – Definitions

Retail Sales - New Mexico Other Public Authority

Variable Name	Definition
S_MUNISCHOOL_NM	Municipal and School Service sales in the New Mexico service area
CONST	Constant variable
C65_bill_ROS_NM_Jun	Cooling degree days (June)
C65_bill_ROS_NM_Jul	Cooling degree days (July)
C65_bill_ROS_NM_Aug	Cooling degree days (August)
C65_bill_ROS_NM_Sep	Cooling degree days (September)
Oct	Seasonal binary variable, October=1, otherwise =0
Bin0511	Binary variable, May 2011=1, otherwise =1
Bin0917	Binary variable, September 2017=1, otherwise =0
Bin0417	Binary variable, April 2017=1, otherwise =0
Bin1112	Binary variable, November 2012=1, otherwise =0
Bin1217	Binary variable, December 2017=1, otherwise =0
Bin0114	Binary variable, January 2014=1, otherwise =0
Bin1016	Binary variable, October 2016=1, otherwise =0
OtherTrend	Binary variable, (month>=November and year>=2018) =1, otherwise =0
COVID_19_Impact_Apr2020_School	Binary variable to account for Covid impacts; Starting April 2020 to June 2023

Table F-37: Retail Sales – Texas Other Public Authority

Retail Sales - Texas Other Public Authority

Dependent Variable: S_MUNISCHOOL_TX				
Method: Least Squares				
Sample: 2008M01 2020M12				
Included observations: 156				
S_MUNISCHOOL_TX = C(1)*CONSTANT + C(2)*TRENDVAR + C(3)*(BINJUN *CDD65B_PAN*C_MUNISCH_TX) + C(4)*(BINJUL *CDD65B_PAN*C_MUNISCH_TX) + C(5)*(BINAUG *CDD65B_PAN*C_MUNISCH_TX) + C(6)*(BINSEP *CDD65B_PAN*C_MUNISCH_TX) + C(7)*(BINOCT *CDD65B_PAN*C_MUNISCH_TX) + C(8)*Bin0317 + C(9)*Bin0917 + C(10)*Bin0814 + C(11)*Bin0316 + [AR(1)=C(12)] + [MA(1)=C(13)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	34618.545	1855.151	18.66077	0.00000
C(2)	-18.683	6.161	-3.03251	0.00289
C(3)	0.002	0.000	4.92185	0.00000
C(4)	0.002	0.000	7.43184	0.00000
C(5)	0.003	0.000	10.04114	0.00000
C(6)	0.005	0.000	12.83228	0.00000
C(7)	0.012	0.001	13.16823	0.00000
C(8)	-6153.489	1936.838	-3.17708	0.00183
C(9)	-4881.717	1980.348	-2.46508	0.01488
C(10)	-3810.756	1984.947	-1.91983	0.05688
C(11)	4847.701	1936.697	2.50308	0.01344
C(12)	0.718	0.185	3.88848	0.00016
C(13)	-0.523	0.224	-2.32901	0.02126

Table F-38: Retail Sales - Texas Other Public Authority – Regression Statistics

Retail Sales - Texas Other Public Authority

Model Statistics	
Adjusted Observations	155
R-Squared	0.7490
Adjusted R-Squared	0.7278
AIC	15.269
BIC	15.524
Log-Likelihood	-1,390.260
Model Sum of Squares	1,672,447,634.315
Sum of Squared Errors	560,522,960.32
Std. Error of Regression	1,986.79
Durbin-Watson Statistic	1.98
Mean dependent var	31,358.08
StdDev dependent var	3,795.97

Table F-39: Retail Sales - Texas Other Public Authority – Definitions

Retail Sales - Texas Other Public Authority

Variable Name	Definition
S_MUNISCHOOL_TX	Municipal and School Service sales in Texas
CONST	Constant variable
TrendVar	Trend variable
C65_bill_MSS_TX_Jun	Cooling degree days (June) multiplied by customers
C65_bill_MSS_TX_Jul	Cooling degree days (July) multiplied by customers
C65_bill_MSS_TX_Aug	Cooling degree days (August) multiplied by customers
C65_bill_MSS_TX_Sep	Cooling degree days (September) multiplied by customers
C65_bill_MSS_TX_Oct	Cooling degree days (October) multiplied by customers
Bin0317	Binary variable for March 2017=1, otherwise=0
Bin0917	Binary variable for September 2017=1, otherwise=0
Bin0814	Binary variable for August 2018=1, otherwise=0
Bin0316	Binary variable for March 2016=1, otherwise=0
AR(1)	Autogressive corrective 1st term
MA(1)	Moving Average 1st term

Table F-40: Retail Customers – New Mexico Total Residential

Retail Customers - New Mexico Total FERC Residential

Dependent Variable: Res_Cust_NM				
Method: Least Squares				
Sample: 2005M01 2020M12				
Included observations: 192				
RES_CUST_NM = C(1)*HH_NM_MA12 + C(2)*BIN0808 + C(3)*Customer_Adjustment + [AR(1)=C(4)] + [AR(2)=C(5)] + [MA(1)=C(6)] + [SMA(1)=C(7)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	896.956	7.780	115.29105	0.0%
C(2)	109.712	51.512	2.12985	3.5%
C(3)	-118.599	56.290	-2.10691	3.6%
C(4)	1.843	0.073	25.12818	0.0%
C(5)	-0.847	0.072	-11.75163	0.0%
C(6)	-0.605	0.113	-5.35167	0.00000
C(7)	0.147	0.076	1.93257	0.05483

Table F-41: Retail Customers - New Mexico Total Residential – Regression Statistics

Retail Customers - New Mexico Total FERC Residential

Model Statistics	
Adjusted Observations	190
R-Squared	0.9995
Adjusted R-Squared	0.9995
AIC	8.868
BIC	8.988
Log-Likelihood	-1,105.101
Model Sum of Squares	2,777,796,607.853
Sum of Squared Errors	1,253,923.39
Std. Error of Regression	82.78
Durbin-Watson Statistic	1.93
Mean dependent var	85,517.80
StdDev dependent var	3,882.64

Table F-42: Retail Customers- New Mexico Total Residential – Definitions

Retail Customers - New Mexico Total FERC Residential

Variable Name	Definition
Res_Cust_NM	New Mexico residential customers
HH_NM_MA12	12-month moving average of Households in New Mexico service area
Bin0808	Binary variable for August 2008=1, otherwise =0
Customer_Adjustment	Binary variable for year = 2016 and (month=9 or month=10 or month=11 or month=12) or year = 2017 and (month=1 or month=2 or month=3 or month=4 or month=5 or month=6 or month =7)
AR(1)	Autoregressive correction term, 1st period
AR(2)	Autoregressive correction term, 2nd period
MA(1)	First-order moving average term
SMA(1)	First-order seasonal moving average term

Table F-43: Retail Customers – Texas Total Residential

Retail Customers - Texas Total FERC Residential

Dependent Variable: TX_Res_Cust
Method: Least Squares
Sample: 2006M01 2020M12
Included observations: 180
TX_RES_CUST = C(1)*NR_TX + C(2)*BIN0307 + C(3)*BIN0808 + C(4)*BIN0908 + C(5)*BINJAN + C(6)*BINFEB + C(7)*BINMAR + C(8)*BINAUG + C(9)*BINOCT + [AR(1)=C(10)] + [MA(1)=C(11)] + [MA(2)=C(12)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	395.208	71.720	5.51043	0.0%
C(2)	-2657.187	106.466	-24.95799	0.0%
C(3)	249.969	116.791	2.14030	3.4%
C(4)	662.663	114.846	5.77001	0.0%
C(5)	172.187	35.290	4.87928	0.0%
C(6)	157.292	36.677	4.28862	0.0%
C(7)	173.810	34.517	5.03544	0.0%
C(8)	109.582	28.050	3.90671	0.0%
C(9)	87.576	27.918	3.13689	0.2%
C(10)	0.997	0.005	184.22571	0.0%
C(11)	0.149	0.075	1.98320	4.9%
C(12)	0.308	0.076	4.02794	0.0%

Table F-44: Retail Customers - Texas Total Residential – Regression Statistics

Retail Customers - Texas Total FERC Residential

Model Statistics	
Adjusted Observations	179
R-Squared	0.9994
Adjusted R-Squared	0.9994
AIC	10.213
BIC	10.427
Log-Likelihood	-1,156.069
Model Sum of Squares	7,532,669,339.310
Sum of Squared Errors	4,267,251.66
Std. Error of Regression	159.85
Durbin-Watson Statistic	1.97
Mean dependent var	197,250.728
StdDev dependent var	6,566.667

Table F-45: Retail Customers - Texas Total Residential – Definitions

Retail Customers - Texas Total FERC Residential

Variable Name	Definition
TX_Res_Cust	Texas residential customer counts
NR_TX	Population in Texas service area
Bin0307	Binary variable for March 2007=1, otherwise =0
Bin0808	Binary variable for August 2008=1, otherwise =0
Bin0908	Binary variable for September 2008=1, otherwise =0
Jan	Seasonal binary for January=1, otherwise=0
Feb	Seasonal binary for February=1, otherwise=0
Mar	Seasonal binary for March=1, otherwise=0
Aug	Seasonal binary for August=1, otherwise=0
Oct	Seasonal binary for October=1, otherwise=0
AR(1)	First-order autoregressive term
MA(1)	First-order moving average term
MA(2)	Second-order moving average term

Table F-46: Retail Customers – New Mexico Small Commercial and Industrial

Retail Customers - New Mexico FERC Small Commercial and Industrial

Dependent Variable: Sm_CI				
Method: Least Squares				
Sample: 2006M01 2020M12				
Included observations: 180				
SM_CI = C(1)*NR_NM_MA12 + C(2)*Trend2016 + C(3)*Bin0118 + C(4)*1118 + [AR(1)=C(5)] + [MA(1)=C(6)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	81.392	11.911	6.83354	0.0%
C(2)	121.539	27.278	4.45556	0.0%
C(3)	32.830	17.124	1.91721	5.7%
C(4)	56.287	17.342	3.24561	0.1%
C(5)	0.996	0.005	187.03341	0.0%
C(6)	0.214	0.075	2.84244	0.5%

Table F-47: Retail Customers - New Mexico Small Commercial and Industrial – Regression Statistics

Retail Customers - New Mexico FERC Small Commercial and Industrial

Model Statistics	
Adjusted Observations	179
R-Squared	0.9997
Adjusted R-Squared	0.9997
AIC	6.647
BIC	6.754
Log-Likelihood	-842.877
Model Sum of Squares	402,603,966.054
Sum of Squared Errors	128,943.39
Std. Error of Regression	27.30
Durbin-Watson Statistic	1.89
Mean dependent var	19,347.15
StdDev dependent var	1,511.34

Table F-48: Retail Customers- New Mexico Small Commercial and Industrial – Definitions

Retail Customers - New Mexico FERC Small Commercial and Industrial

Variable Name	Definition
Sm_CI	Small Commercial & Industrial FERC Class New Mexico customer counts
NR_NM_MA12	12-month moving average of Population in New Mexico service area
Trend2016	Binary trend variable starting January 2016 to December 2050
Bin0118	Binary variable for January 2018 = 1, otherwise = 0
Bin1118	Binary variable for November 2018 = 1, otherwise = 0
AR(1)	First-order autoregressive term
MA(1)	First-order Moving Average

Table F-49: Retail Customers – Texas Small Commercial and Industrial

Retail Customers - Texas FERC Small Commercial and Industrial

Dependent Variable: TX_Sm_CI				
Method: Least Squares				
Sample: 2005M01 2020M12				
Included observations: 192				
TX_SM_CI = C(1)*NR_TX_Log + C(2)*BIN0307 + C(3)*BIN1108 + C(4)*BIN0210 + C(5)*BIN0910 + C(6)*BIN1010 + [AR(1)=C(7)] + [MA(1)=C(8)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	88.066	9.403	9.36529	0.0%
C(2)	3039.013	36.781	82.62525	0.0%
C(3)	95.712	36.760	2.60370	1.0%
C(4)	-96.325	36.758	-2.62051	1.0%
C(5)	783.738	45.454	17.24250	0.0%
C(6)	817.495	44.707	18.28550	0.0%
C(7)	0.996	0.006	156.87221	0.0%
C(8)	0.128	0.075	1.69454	9.2%

Table F-50: Retail Customers - Texas FERC Small Commercial and Industrial – Regression Statistics

Retail Customers - Texas FERC Small Commercial and Industrial

Model Statistics	
Adjusted Observations	191
R-Squared	0.9989
Adjusted R-Squared	0.9988
AIC	8.081
BIC	8.217
Log-Likelihood	-1,034.716
Model Sum of Squares	506,890,950.411
Sum of Squared Errors	567,567.32
Std. Error of Regression	55.69
Durbin-Watson Statistic	1.98
Mean dependent var	46,425.66
StdDev dependent var	1,644.02

Table F-51: Retail Customers - Texas Small Commercial and Industrial – Definitions

Retail Customers - Texas FERC Small Commercial and Industrial

Variable Name	Definition
TX_Sm_CI	Texas small commercial and industrial customer counts
NR_TX	Population in Texas service area
Bin0307	Binary variable for March 2007=1, otherwise =0
Bin1108	Binary variable for November 2008=1, otherwise =0
Bin0210	Binary variable for February 2010=1, otherwise =0
Bin0910	Binary variable for September 2010=1, otherwise =0
Bin1010	Binary variable for October 2010=1, otherwise =1
AR(1)	First-order autoregressive term
AR(2)	Second-order autoregressive term

Table F-52: Retail Customers – New Mexico Other Public Authority

Retail Customers - New Mexico FERC Other Public Authority

Dependent Variable: Other_Pub_Auth				
Method: Least Squares				
Sample: 2008M05 2020M12				
Included observations: 152				
OTHER_PUB_AUTH = C(1)*HH_NM_Log + C(2)*BIN0908 + C(3)*BIN0412 + C(4)*BIN0116 + C(5)*BIN0217 + [AR(1)=C(6)] + [MA(1)=C(7)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	380.917	4.858	78.41666	0.0%
C(2)	6.550	2.193	2.98617	0.3%
C(3)	8.573	2.156	3.97616	0.0%
C(4)	8.070	2.151	3.75259	0.0%
C(5)	-24.687	2.148	-11.49284	0.0%
C(6)	0.980	0.005	188.76758	0.0%
C(7)	0.149	0.085	1.75680	8.1%

Table F-53: Retail Customers - New Mexico Other Public Authority – Regression Statistics

Retail Customers - New Mexico FERC Other Public Authority

Model Statistics	
Adjusted Observations	151
R-Squared	0.9975
Adjusted R-Squared	0.9974
AIC	2.414
BIC	2.554
Log-Likelihood	-389.518
Model Sum of Squares	619,410.577
Sum of Squared Errors	1,538.52
Std. Error of Regression	3.27
Durbin-Watson Statistic	2.00
Mean dependent var	1,681.27
StdDev dependent var	65.43

Table F-54: Retail Customers- New Mexico Other Public Authority – Definitions

Retail Customers - New Mexico FERC Other Public Authority

Variable Name	Definition
Other_Pub_Auth	Public Authority FERC Class New Mexico customer counts
Economic.HH_NM_Log	Log of Households in the New Mexico service area
Binary.Bin0908	Binary variable for September 2008=1, otherwise =0
Binary.Bin0412	Binary variable for April 2012=1, otherwise =0
Binary.Bin0116	Binary variable for January 2016=1, otherwise =0
Binary.Bin0217	First-order autoregressive term
AR(1)	Autoregressive correction term, 1st period
MA(1)	First-order Moving Average term

Table F-55: Retail Customers – Texas Other Public Authority

Retail Customers - Texas FERC Other Public Authority

Dependent Variable: TX_OSPA				
Method: Least Squares				
Sample: 2005M01 2020M12				
Included observations: 192				
TX_OSPA = C(1)*NR_TX_Log + C(2)*BIN0905 + C(3)*BIN0809 + C(4)*BIN0310 + C(5)*BIN0317 + C(6)*CUSTOMERSHIFT0407 + [AR(1)=C(7)] + [AR(2)=C(8)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	697.354	5.256	132.67755	0.0%
C(2)	8.300	3.399	2.44165	1.6%
C(3)	8.927	3.410	2.61765	1.0%
C(4)	136.185	3.397	40.09490	0.0%
C(5)	-21.406	3.411	-6.27585	0.0%
C(6)	71.552	5.346	13.38464	0.0%
C(7)	1.221	0.072	16.98194	0.0%
C(8)	-0.237	0.071	-3.35438	0.1%

Table F-56: Retail Customers - Texas Other Public Authority – Regression Statistics

Retail Customers - Texas FERC Other Public Authority

Model Statistics	
Adjusted Observations	190
R-Squared	0.9988
Adjusted R-Squared	0.9987
AIC	3.432
BIC	3.569
Log-Likelihood	-587.622
Model Sum of Squares	4,427,191.812
Sum of Squared Errors	5,402.66
Std. Error of Regression	5.45
Durbin-Watson Statistic	2.04
Mean dependent var	4,367.09
StdDev dependent var	158.65

Table F-57: Retail Customers- Texas Other Public Authority – Definitions

Retail Customers - Texas FERC Other Public Authority

Variable Name	Definition
TX_OSPA	Texas other public authority customer counts
NR_TX_Log	Log of Population in Texas service area
Bin0905	Binary variable for September 2005=1, otherwise =0
Bin0809	Binary variable for August 2009=1, otherwise =0
Bin0310	Binary variable for March 2010=1, otherwise =0
Bin0317	Binary variable for March 2017=1, otherwise =0
CustomerShift0407	Binary for customer shift starting April 2007=1, otherwise =0
AR(1)	First-order autoregressive term
MA(1)	First-order moving average term

Table F-58: Wholesale Sales – Central Valley

Wholesales Sales - Central Valley

Dependent Variable: S_Central Valley

Method: Least Squares

Sample: 2006M01 2020M12

Included observations: 180

S_CentralValley=C(1)*Extraction_Index+C(2)*BINJAN+C(3)*BINMAR+C(4)*BINAPR+C(5)*BINMAY+C(6)*C65_CAL_ROS_NM_MAY+C(7)*C65_CAL_ROS_NM_JUN+C(8)*C65_CAL_ROS_NM_JUL+C(9)*C65_CAL_ROS_NM_AUG+C(10)C65_CAL_ROS_NM_SEP+C(11)*BINOCT+C(12)*BINNOV+C(13)*BINDEC+C(14)*BIN0710+C(15)*BIN0211+C(16)*BIN1114+C(17)*BIN0215+C(18)*BIN0416+C(19)*BIN1217+C(20)*BIN0419+C(21)*BIN0908+C(22)*BIN0520+[AR(1)=C(23)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	12,962.0965	201.5280	64.3191	0.00%
C(2)	5,212.5278	515.5687	10.1102	0.00%
C(3)	7,585.7274	516.2084	14.6951	0.00%
C(4)	7,226.6295	679.2461	10.6392	0.00%
C(5)	4,759.0417	1,315.1387	3.6187	0.04%
C(6)	14.7647	5.3847	2.7420	0.68%
C(7)	23.4295	1.5820	14.8099	0.00%
C(8)	27.5720	1.4213	19.3991	0.00%
C(9)	27.6281	1.5042	18.3675	0.00%
C(10)	20.1133	2.7401	7.3403	0.00%
C(11)	3,824.8668	758.7895	5.0407	0.00%
C(12)	1,624.8858	741.7145	2.1907	2.99%
C(13)	4,378.4721	672.3446	6.5122	0.00%
C(14)	-3,816.0518	1,496.8512	-2.5494	1.17%
C(15)	-7,865.8344	1,511.0469	-5.2056	0.00%
C(16)	3,795.6610	1,512.6079	2.5093	1.31%
C(17)	-4,810.2017	1,511.8328	-3.1817	0.18%
C(18)	-4,050.2816	1,523.3538	-2.6588	0.87%
C(19)	3,232.2374	1,515.0764	2.1334	3.44%
C(20)	-3,808.7180	1,516.5028	-2.5115	1.30%
C(21)	-6,628.9145	1,496.3465	-4.4301	0.00%
C(22)	-9,377.7214	1,639.4367	-5.7201	0.00%
C(23)	0.8253	0.0459	17.9966	0.00%

Table F-59: Wholesale Sales – Central Valley – Regression Statistics

Wholesales Sales - Central Valley

Model Statistics	
Adjusted Observations	179
R-Squared	0.9286
Adjusted R-Squared	0.9185
AIC	15.218
BIC	15.627
Log-Likelihood	-1,592.977
Model Sum of Squares	7,317,874,441.644
Sum of Squared Errors	562,631,019.19
Std. Error of Regression	1,899.11
Durbin-Watson Statistic	2.11
Mean dependent var	66,743.49
StdDev dependent var	6,659.74

Table F-60: Wholesale Sales – Central Valley – Definitions

Wholesales Sales - Central Valley

Variable Name	Definition
S_CentralValley	Central Valley sales
Extraction_Index	Oil and Gas Extraction Index
Jan	Seasonal binary variable, January=1, otherwise =0
Mar	Seasonal binary variable, March=1, otherwise =0
Apr	Seasonal binary variable, April=1, otherwise =0
May	Seasonal binary variable, May=1, otherwise =0
C65_cal_ROS_NM_May	May cooling degree days
C65_cal_ROS_NM_Jun	June cooling degree days
C65_cal_ROS_NM_Jul	July cooling degree days
C65_cal_ROS_NM_Aug	August cooling degree days
C65_cal_ROS_NM_Sep	September cooling degree days
Oct	Seasonal binary variable, October=1, otherwise =0
Nov	Seasonal binary variable, November=1, otherwise =0
Dec	Seasonal binary variable, December=1, otherwise =0
Bin0710	Binary variable for July 2010=1, otherwise =0
Bin0211	Binary variable for February 2011=1, otherwise =0
Bin1114	Binary variable for November 2014=1, otherwise =0
Bin0215	Binary variable for February 2015=1, otherwise =0
Bin0416	Binary variable for April 2016=1, otherwise =0
Bin1217	Binary variable for December 2017=1, otherwise =0
Bin0419	Binary variable for April 2019=1, otherwise =0
Bin0908	Binary variable for September 2008=1, otherwise =0
Bin0520	Binary variable for May 2020=1, otherwise =0
AR(1)	First-order autoregressive term

Table F-61: Wholesale Sales – Farmers

Wholesales Sales - Farmers

<table>
<tr><td colspan="5">Dependent Variable: S_Farmers</td></tr>
<tr><td colspan="5">Method: Least Squares</td></tr>
<tr><td colspan="5">Sample: 2007M01 2020M12</td></tr>
<tr><td colspan="5">Included observations: 168</td></tr>
<tr><td colspan="5">S_Farmers=C(1)*CGCP_FARMERS_LOG+C(2)*BINJAN+C(3)*BINFEB+C(4)*BINAPR+C(5)*C65_CAL_ROS_NM_JUN +C(6)*C65_CAL_ROS_NM_JUL+C(7)*C65_CAL_ROS_NM_AUG+C(8)*BINOCT+C(9)*BINNOV+C(10)*BINDEC+C(11)*BIN0515+C(12)*NM_PRECIP_MARAPR+C(13)*BIN0916+C(14)*BIN0817+C(15)*BIN0614+C(16)*FarmersLoadStable+[AR(1)=C(17)]</td></tr>
<tr><td>Variable</td><td>Coefficient</td><td>Std. Error</td><td>t-Statistic</td><td>Prob.</td></tr>
<tr><td>C(1)</td><td>4044.650</td><td>101.535</td><td>39.835</td><td>0.00%</td></tr>
<tr><td>C(2)</td><td>-3178.167</td><td>696.124</td><td>-4.566</td><td>0.00%</td></tr>
<tr><td>C(3)</td><td>-5231.456</td><td>575.615</td><td>-9.088</td><td>0.00%</td></tr>
<tr><td>C(4)</td><td>1546.206</td><td>457.072</td><td>3.383</td><td>0.09%</td></tr>
<tr><td>C(5)</td><td>7.347</td><td>1.092</td><td>6.728</td><td>0.00%</td></tr>
<tr><td>C(6)</td><td>16.875</td><td>1.073</td><td>15.726</td><td>0.00%</td></tr>
<tr><td>C(7)</td><td>17.396</td><td>1.007</td><td>17.279</td><td>0.00%</td></tr>
<tr><td>C(8)</td><td>-3732.422</td><td>554.006</td><td>-6.737</td><td>0.00%</td></tr>
<tr><td>C(9)</td><td>-5255.219</td><td>682.097</td><td>-7.705</td><td>0.00%</td></tr>
<tr><td>C(10)</td><td>-3778.028</td><td>720.267</td><td>-5.245</td><td>0.00%</td></tr>
<tr><td>C(11)</td><td>-5031.576</td><td>1691.376</td><td>-2.975</td><td>0.34%</td></tr>
<tr><td>C(12)</td><td>-946.336</td><td>531.515</td><td>-1.780</td><td>7.70%</td></tr>
<tr><td>C(13)</td><td>-4802.837</td><td>1654.024</td><td>-2.904</td><td>0.42%</td></tr>
<tr><td>C(14)</td><td>-6202.416</td><td>1658.656</td><td>-3.739</td><td>0.03%</td></tr>
<tr><td>C(15)</td><td>-3275.615</td><td>1673.947</td><td>-1.957</td><td>5.22%</td></tr>
<tr><td>C(16)</td><td>-3470.050</td><td>1147.886</td><td>-3.023</td><td>0.30%</td></tr>
<tr><td>C(17)</td><td>0.755</td><td>0.054</td><td>14.066</td><td>0.00%</td></tr>
</table>

Table F-62: Wholesale Sales – Farmers – Regression Statistics

Wholesales Sales - Farmers

<table>
<tr><th colspan="2">Model Statistics</th></tr>
<tr><td>Adjusted Observations</td><td>167</td></tr>
<tr><td>R-Squared</td><td>0.8969</td></tr>
<tr><td>Adjusted R-Squared</td><td>0.8859</td></tr>
<tr><td>AIC</td><td>15.328</td></tr>
<tr><td>BIC</td><td>15.646</td></tr>
<tr><td>Log-Likelihood</td><td>-1,499.883</td></tr>
<tr><td>Model Sum of Squares</td><td>5,381,082,541.606</td></tr>
<tr><td>Sum of Squared Errors</td><td>618,485,811.06</td></tr>
<tr><td>Std. Error of Regression</td><td>2,030.58</td></tr>
<tr><td>Durbin-Watson Statistic</td><td>1.96</td></tr>
<tr><td>Mean dependent var</td><td>32,432.05</td></tr>
<tr><td>StdDev dependent var</td><td>6,020.69</td></tr>
</table>

Table F-63: Wholesale Sales – Farmers – Definitions

Wholesales Sales - Farmers

Variable Name	Definition
S_Farmers	Farmers sales
CGCP_Farmers	New Mexico Gross County Product - Farmers Service Area
Jan	Seasonal binary variable, January=1, otherwise =0
Feb	Seasonal binary variable, February=1, otherwise =0
Apr	Seasonal binary variable, April=1, otherwise =1
C65_cal_ROS_NM_Jun	June cooling degree days
C65_cal_ROS_NM_Jul	July cooling degree days
C65_cal_ROS_NM_Aug	August cooling degree days
Oct	Seasonal binary variable, October=1, otherwise =0
Nov	Seasonal binary variable, November=1, otherwise =0
Dec	Seasonal binary variable, December=1, otherwise =0
Bin0515	Binary variable for May 2015=1, otherwise =0
NM_Precip_MarApr	Precipitation for March and April, otherwise=0
Bin0916	Binary variable for September 2016=1, otherwise =0
Bin0817	Binary variable for August 2017=1, otherwise =0
Bin0614	Binary variable for June 2014=1, otherwise =0
FarmersLoadStable	Binary variable for (month>January and year=2015)=1 , otherwise =0
AR(1)	First-order autoregressive term

Table F-64: Wholesale Sales – Lea County

Wholesale - Lea County

Dependent Variable: S_LeaCounty				
Method: Least Squares				
Sample: 2006M01 2020M12				
Included observations: 180				
S_LEACOUNTY=C(1)*EXTRACTION_INDEX+C(2)*FEB+C(3)*C65_CAL_ROS_NM_MAY+C(4)*C65_CAL_ROS_NM_JUN+C(5)*C65_CAL_ROS_NM_JUL+C(6)*C65_CAL_ROS_NM_AUG+C(7)*C65_CAL_ROS_NM_SEP+C(8)*BIN0810+C(9)*BIN0914+C(10)*BIN1218+C(11)*BIN0419+C(12)*BIN0519+[AR(1)=C(13)]+[SMA(1)=C(14)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	19,955.449	389.649	51.214	0.00%
C(2)	(8,362.747)	1,676.085	(4.989)	0.00%
C(3)	36.863	8.188	4.502	0.00%
C(4)	31.555	4.864	6.487	0.00%
C(5)	52.710	4.474	11.781	0.00%
C(6)	60.111	4.558	13.188	0.00%
C(7)	28.709	6.988	4.108	0.01%
C(8)	11,542.302	5,025.815	2.297	2.29%
C(9)	(16,901.114)	5,028.791	(3.361)	0.10%
C(10)	(31,574.789)	4,942.108	(6.389)	0.00%
C(11)	(28,158.201)	5,581.820	(5.045)	0.00%
C(12)	(33,736.420)	5,593.271	(6.032)	0.00%
C(13)	0.655	0.061	10.803	0.00%
C(14)	0.275	0.085	3.259	0.14%

Table F-65: Wholesale Sales – Lea County – Regression Statistics

Wholesale - Lea County

Model Statistics	
Adjusted Observations	179
R-Squared	0.8428
Adjusted R-Squared	0.8304
AIC	17.525
BIC	17.775
Log-Likelihood	-1,808.500
Model Sum of Squares	33,514,890,743.334
Sum of Squared Errors	6,252,280,149.23
Std. Error of Regression	6,155.70
Durbin-Watson Statistic	1.97
Mean dependent var	99,039.84
StdDev dependent var	14,923.21

Table F-66: Wholesale Sales – Lea County – Definitions

Wholesale - Lea County

Variable Name	Definition
S_LeaCounty	Lea County sales
Extraction_Index	Oil and Gas Extraction Index
Feb	Seasonal binary variable for February
C65_cal_ROS_NM_May	May cooling degree days
C65_cal_ROS_NM_Jun	June cooling degree days
C65_cal_ROS_NM_Jul	July cooling degree days
C65_cal_ROS_NM_Aug	August cooling degree days
C65_cal_ROS_NM_Sep	September cooling degree days
Bin0810	Binary variable for August 2010=1, otherwise =0
Bin0914	Binary variable for September 2014=1, otherwise =0
BIN1218	Binary variable for December 2018=1, otherwise =0
BIN0419	Binary variable for April 2019=1, otherwise =0
BIN0519	Binary variable for May 2019=1, otherwise =0
AR(1)	First-order autoregressive term
SMA(1)	First-order seasonal moving average term

Table F-67: Wholesale Sales – Roosevelt

Wholesales Sales - Roosevelt

Dependent Variable: S_Roosevelt

Method: Least Squares

Sample: 2008M01 2020M12

Included observations: 156

S_ROOSEVELT=C(1)*CONST+C(2)*TREND2012+C(3)*BINMAR+C(4)*BINAPR+C(5)*BINMAY+C(6)*C65_CAL_ROS_NM_JUN+C(7)*C65_CAL_ROS_NM_JUL+C(8)*C65_CAL_ROS_NM_AUG+C(9)*C65_CAL_ROS_NM_SEP+C(10)*BINNOV+C(11)*BIN0515+C(12)*BIN1015+C(13)*BIN0916+C(14)*BIN0817+[AR(1)=C(15)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	14,506.053	509.136	28.491	0.00%
C(2)	(36.589)	9.211	(3.972)	0.01%
C(3)	2,673.173	278.058	9.614	0.00%
C(4)	3,380.847	352.452	9.592	0.00%
C(5)	2,181.768	391.361	5.575	0.00%
C(6)	7.780	0.781	9.956	0.00%
C(7)	11.119	0.675	16.474	0.00%
C(8)	12.103	0.658	18.388	0.00%
C(9)	8.769	1.019	8.602	0.00%
C(10)	(766.034)	218.897	(3.500)	0.06%
C(11)	(3,079.331)	812.407	(3.790)	0.02%
C(12)	(2,318.457)	813.842	(2.849)	0.51%
C(13)	(3,503.395)	802.335	(4.366)	0.00%
C(14)	(4,086.121)	804.292	(5.080)	0.00%
C(15)	0.758	0.057	13.319	0.00%

Table F-68: Wholesale Sales – Roosevelt – Regression Statistics

Wholesales Sales - Roosevelt

Model Statistics	
Adjusted Observations	155
R-Squared	0.9107
Adjusted R-Squared	0.9018
AIC	13.871
BIC	14.165
Log-Likelihood	-1,279.912
Model Sum of Squares	1,376,638,282.440
Sum of Squared Errors	134,967,320.65
Std. Error of Regression	981.86
Durbin-Watson Statistic	2.01
Mean dependent var	15,154.32
StdDev dependent var	3,128.39

Table F-69: Wholesale Sales – Roosevelt – Definitions

Wholesales Sales - Roosevelt

Variable Name	Definition
S_Roosevelt	Roosevelt sales
CONST	Constant Variable
Trend2012	Trend variable beginning in January 2012
Mar	Seasonal binary variable for March
Apr	Seasonal binary variable for April
May	Seasonal binary variable for May
C65_cal_ROS_NM_Jun	June cooling degree days
C65_cal_ROS_NM_Jul	July cooling degree days
C65_cal_ROS_NM_Aug	August cooling degree days
C65_cal_ROS_NM_Sep	September cooling degree days
Nov	Seasonal binary variable for November
Bin0515	Binary variable for May 2015=1, otherwise =0
Bin1015	Binary variable for October 2015=1, otherwise =0
Bin0916	Binary variable for September 2016=1, otherwise =0
Bin0817	Binary variable for August 2017=1, otherwise =0
AR(1)	First-order autoregressive term

Table F-70: Wholesale Sales – Golden Spread Full Load

Wholesales - GSEC_FullLoad_Sales

Dependent Variable: GSECSALES_LOG				
Method: Least Squares				
Sample: 2004M01 2020M12				
Included observations: 204				
GSECSALES_LOG=C(1)*CONST+C(2)*C65_CAL_PAN_MAY+C(3)*C65_CAL_PAN_JUNE+C(4)*C65_CAL_PAN_JULY+C(5)*C65_CAL_PAN_AUG+C(6)*C65_CAL_PAN_SEP+C(7)*Bin0407+C(8)*BIN0113+C(9)*BIN0916+C(10)*BIN0817+C(11)*PRECIP_CAL_PANAPRTOJUL+C(12)*Feb+C(13)*Mar+C(14)*Apr+C(15)*May+C(16)*Bin0417+C(17)*LogEE_TX_MA+[AR(1)=C(18)]+[MA(1)=C(19)]				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-7.412	1.655	-4.480	0.00%
C(2)	0.001	0.000	5.401	0.00%
C(3)	0.001	0.000	17.639	0.00%
C(4)	0.002	0.000	26.027	0.00%
C(5)	0.002	0.000	27.197	0.00%
C(6)	0.001	0.000	11.947	0.00%
C(7)	-0.275	0.070	-3.932	0.01%
C(8)	-0.556	0.067	-8.273	0.00%
C(9)	-0.464	0.069	-6.746	0.00%
C(10)	-0.216	0.068	-3.194	0.17%
C(11)	-0.032	0.005	-5.877	0.00%
C(12)	-0.085	0.023	-3.651	0.04%
C(13)	0.116	0.031	3.792	0.02%
C(14)	0.381	0.033	11.571	0.00%
C(15)	0.213	0.053	4.000	0.01%
C(16)	-0.278	0.070	-3.987	0.01%
C(17)	3.675	0.303	12.114	0.00%
C(18)	0.310	0.107	2.894	0.43%
C(19)	0.454	0.102	4.435	0.00%

Table F-71: Wholesale Sales – Golden Spread Full Load – Regression Statistics

Wholesales - GSEC_FullLoad_Sales

Model Statistics	
Adjusted Observations	203
R-Squared	0.9489
Adjusted R-Squared	0.9439
AIC	-4.796
BIC	-4.486
Log-Likelihood	217.725
Model Sum of Squares	25.822
Sum of Squared Errors	1.39
Std. Error of Regression	0.09
Durbin-Watson Statistic	1.98
Mean dependent var	12.87
StdDev dependent var	0.37

Table F-72: Wholesale Sales – Golden Spread Full Load – Definitions

Wholesales - GSEC_FullLoad_Sales

Variable Name	Definition
GSECSales_Log	Log of Golden Spread full load sales plus Tri-County Sales
CONST	Constant variable
C65_Cal_Pan_May	May cooling degree days
C65_cal_Panhandle_Jun	June cooling degree days
C65_cal_Panhandle_Jul	July cooling degree days
C65_cal_Panhandle_Aug	August cooling degree days
C65_cal_Panhandle_Sep	September cooling degree days
Bin0407	Binary variable for April 2007=1, otherwise =0
Bin0113	Binary variable for January 2013=1, otherwise =0
Bin0916	Binary variable for September 2016=1, otherwise =0
Bin0817	Binary variable for August 2017=1, otherwise =0
Precip_cal_PanhandleAprtoJul	Precipitation, April May June and July
Feb	Seasonal binary for February=1, otherwise=0
Mar	Seasonal binary for March=1, otherwise=0
Apr	Seasonal binary for April=1, otherwise=0
May	Seasonal binary for May=1, otherwise=0
Bin0417	Binary variable for April 2017=1, otherwise=0
LogEE_TX_MA	Log of 12 month moving average Non-farm Employment in Texas service a
AR(1)	First-order autoregressive term
MA(1)	First-order moving average term

Table F-73: Coincident Peak Demand – Retail

Coincident Peak Demand - Retail

Dependent Variable: Retail_Load_Log
Method: Least Squares
Sample: 2007M01 2020M12
Included observations: 168

LOG(RETAILLOAD-CELANESELOAD+RETAIL_INTERRUPTIONS-LUBBLOAD+SUNRAYII) = C(1) + C(2)*LOG(@MOVAV(TOTAL_RETAIL_SALES-S_CELANESE_TX+DSM_MWH_SAVINGS-LUBB_SALES-NEW_RETAIL_LOAD_SALES+SUNRAYIISALES,12)) + C(3)*(JAN*HDD65_PD_SPS*CUST_SPS) + C(4)*(FEB*HDD65_PD_SPS*CUST_SPS) + C(5)*(MAR*HDD65_PD_SPS*CUST_SPS)+ C(6)*(APR*CDD65_PD_SPS*CUST_SPS) + C(7)*(MAY*CDD65_PD_SPS*CUST_SPS) + C(8)*(JUN*CDD65_PD_SPS*CUST_SPS) + C(9)*(JUL*CDD65_PD_SPS*CUST_SPS) + C(10)*(AUG*CDD65_PD_SPS*CUST_SPS) + C(11)*(SEP*CDD65_PD_SPS*CUST_SPS) + C(12)*(OCT*CDD65_PD_SPS*CUST_SPS) + C(13)*(NOV*HDD65_PD_SPS*CUST_SPS) + C(14)*(DEC*HDD65_PD_SPS*CUST_SPS) + C(15)*BIN1008 + C(16)*BIN1011 + C(17)*BIN0415 + C(18)*BIN0316 + C(19)*BIN0118 + C(20)*BIN2020 + C(21)*BINJUN + C(22)*BINJUL + C(23)*BINAUG + C(24)*BINSEP + [MA(1)=C(25)] +

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-3.588	0.712	-5.03603	0.00%
C(2)	0.797	0.050	15.93460	0.00%
C(3)	0.000	0.000	10.52449	0.00%
C(4)	0.000	0.000	10.50991	0.00%
C(5)	0.000	0.000	5.28083	0.00%
C(6)	0.000	0.000	7.43580	0.00%
C(7)	0.000	0.000	17.58511	0.00%
C(8)	0.000	0.000	5.04123	0.00%
C(9)	0.000	0.000	4.02160	0.01%
C(10)	0.000	0.000	2.38387	1.84%
C(11)	0.000	0.000	4.97752	0.00%
C(12)	0.000	0.000	10.04931	0.00%
C(13)	0.000	0.000	7.30365	0.00%
C(14)	0.000	0.000	11.17656	0.00%
C(15)	-0.083	0.030	-2.78298	0.61%
C(16)	-0.084	0.029	-2.88441	0.45%
C(17)	-0.064	0.030	-2.15983	3.25%
C(18)	-0.093	0.028	-3.27755	0.13%
C(19)	0.063	0.029	2.15783	3.26%
C(20)	-0.036	0.015	-2.47661	1.44%
C(21)	0.092	0.042	2.18554	3.05%
C(22)	0.178	0.040	4.46264	0.00%
C(23)	0.203	0.053	3.80642	0.02%
C(24)	0.077	0.036	2.12494	3.53%
C(25)	0.329	0.085	3.86315	0.02%
C(26)	0.232	0.086	2.69271	0.79%

Table F-74: Coincident Peak Demand – Retail – Regression Statistics

Coincident Peak Demand - Retail

Model Statistics	
Adjusted Observations	168
R-Squared	0.9581
Adjusted R-Squared	0.9508
AIC	-6.880
BIC	-6.397
Log-Likelihood	365.562
Model Sum of Squares	2.900
Sum of Squared Errors	0.13
Std. Error of Regression	0.03
Durbin-Watson Statistic	1.98
Mean dependent var	7.93
StdDev dependent var	0.13

Table F-75: Coincident Peak Demand – Retail – Definitions

Coincident Peak Demand - Retail

Variable Name	Definition
Retail_Load_Log	SPS retail coincident peak demand
CONST	Constant variable
Retail_Sales_LogMA12	Log of 12 month moving average of retail sales
H65_bill_Retail_SPS_Jan	Heating degree days (January) multiplied by customers
H65_bill_Retail_SPS_Feb	Heating degree days (February) multiplied by customers
H65_bill_Retail_SPS_Mar	Heating degree days (March) multiplied by customers
C65_bill_Retail_SPS_Apr	Cooling degree days (April) multiplied by customers
C65_bill_Retail_SPS_May	Cooling degree days (May) multiplied by customers
C65_bill_Retail_SPS_Jun	Cooling degree days (June) multiplied by customers
C65_bill_Retail_SPS_Jul	Cooling degree days (July) multiplied by customers
C65_bill_Retail_SPS_Aug	Cooling degree days (August) multiplied by customers
C65_bill_Retail_SPS_Sep	Cooling degree days (September) multiplied by customers
C65_bill_Retail_SPS_Oct	Cooling degree days (October) multiplied by customers
H65_bill_Retail_SPS_Nov	Heating degree days (November) multiplied by customers
H65_bill_Retail_SPS_Dec	Heating degree days (December) multiplied by customers
Bin1008	Binary variable for October 2008=1, otherwise =0
Bin1011	Binary variable for October 2011=1, otherwise =0
Bin0415	Binary variable for April 2015=1, otherwise =0
Bin0316	Binary variable for March 2016=1, otherwise =0
Bin0118	Binary variable for January 2018=1, otherwise=0
Bin2020	Binary variable for year 2020=1, otherwise=0
Jun	Seasonal binary variable for June=1, otherwise=0
Jul	Seasonal binary variable for July=1, otherwise=0
Aug	Seasonal binary variable for August=1, otherwise=0
Sep	Seasonal binary variable for September=1, otherwise=0
MA(1)	First-order moving average term
MA(2)	Second-order moving average term

Table F-76: Probability Distribution – Full Requirement Energy Excluding WTMPA

Full Requirement Energy Excluding WTMPA
Probability Energy

Dependent Variable: Energy
Method: Least Squares
Sample: 2000M01 2020M12
Included observations: 252

Energy = C(1) + C(2)*(MOVAV(CGSPNM+CGCPTX),12) + C(3)*(CDD65_SPS*BINMAY*TOTAL_CUSTOMERS) + C(4)*(CDD65_SPS*BINJUN*TOTAL_CUSTOMERS) + C(5)*(CDD65_SPS*BINJUL*TOTAL_CUSTOMERS) + C(6)*(CDD65_SPS*BINAUG*TOTAL_CUSTOMERS) + C(7)*(CDD65_SPS*BINSEP*TOTAL_CUSTOMERS) + C(8)*(HDD65_SPS*BINJAN*TOTAL_CUSTOMERS) + C(9)*(HDD65_SPS*BINFEB*TOTAL_CUSTOMERS) + C(10)*(HDD65_SPS*BINMAR*TOTAL_CUSTOMERS) + C(11)*(HDD65_SPS*BINOCT*TOTAL_CUSTOMERS) + C(12)*(HDD65_SPS*BINNOV*TOTAL_CUSTOMERS) + C(13)*(CDD65_SPS*BINDEC*TOTAL_CUSTOMERS) + C(14)*BIN0412 + C(15)*BINFEB + [AR(1)=C(16)] + [AR(2)=C(17)]

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	1011820.833	224750.472	4.50197	0.00%
C(2)	12.637	3.712	3.40437	0.08%
C(3)	0.002	0.000	15.93293	0.00%
C(4)	0.002	0.000	26.79662	0.00%
C(5)	0.003	0.000	40.39966	0.00%
C(6)	0.003	0.000	38.26489	0.00%
C(7)	0.002	0.000	13.80201	0.00%
C(8)	0.001	0.000	13.51462	0.00%
C(9)	0.001	0.000	3.11468	0.21%
C(10)	0.000	0.000	5.58673	0.00%
C(11)	0.001	0.000	3.89976	0.01%
C(12)	0.000	0.000	2.88904	0.42%
C(13)	0.001	0.000	15.08933	0.00%
C(14)	-417986.217	36369.816	-11.49267	0.00%
C(15)	-227716.222	58731.318	-3.87725	0.01%
C(16)	0.719	0.063	11.32320	0.00%
C(17)	0.218	0.064	3.41769	0.08%

Table F-77: Probability Distribution – Full Requirement Energy Excluding WTMPA – Regression Statistics

Probability Energy

Model Statistics	
Adjusted Observations	250
R-Squared	0.9743
Adjusted R-Squared	0.9725
AIC	21.485
BIC	21.725
Log-Likelihood	-3,023.369
Model Sum of Squares	17,715,413,838,134
Sum of Squared Errors	467,438,829,839.67
Std. Error of Regression	44,790.35
Durbin-Watson Statistic	2.01
Mean dependent var	1,866,130.66
StdDev dependent var	272,757.55

Table F-78: Probability Distribution – Full Requirement Energy Excluding WTMPA – Definitions

Probability Energy

Variable Name	Definition
Energy	SPS full requirement energy, excluding WTMPA sales
CONST	Constant
CGCP_SPS_MA12	12-Month Moving Average of New Mexico and Texas Gross County Product
C65_SPS_May	May weather index for customer weighted cooling degree days
C65_SPS_Jun	June weather index for customer weighted cooling degree days
C65_SPS_Jul	July weather index for customer weighted cooling degree days
C65_SPS_Aug	August weather index for customer weighted cooling degree days
C65_SPS_Sep	September weather index for customer weighted cooling degree days
H65_SPS_Jan	January weather index for customer weighted heating degree days
H65_SPS_Feb	February weather index for customer weighted heating degree days
H65_SPS_Mar	March weather index for customer weighted heating degree days
H65_SPS_Oct	October weather index for customer weighted heating degree days
H65_SPS_Nov	November weather index for customer weighted heating degree days
H65_SPS_Dec	December weather index for customer weighted heating degree days
Bin0412	Binary variable for April 2012=1, otherwise =0
Feb	Seasonal Binary variable for February=1, otherwise=0
AR(1)	First-order autoregressive term
AR(2)	Second-order autoregressive term

Table F-79: Probability Distribution – Full Requirement Peak Demand Excluding WTMPA

Full Requirement Peak Excluding WTMPA
Probability Peak Demand

Dependent Variable: Peak
Method: Least Squares
Sample: 2000M01 2020M12
Included observations: 252

PEAK = C(1)*(MOVAV(ENERGY,12) + C(2)*(CDD65_SPS*BINAPR) + C(3)*(CDD65_SPS*BINMAY) + C(4)*(BINJUN*((MAXTEMP+MINTEMP)/2) + C(5)*(BINJUL*((MAXTEMP+MINTEMP)/2) + C(6)*(BINAUG*((MAXTEMP+MINTEMP)/2) + C(7)*(CDD65_SPS*BINSEP) + C(8)*(CDD65_SPS*BINOCT) + C(9)*TREND_PD + C(10)*HDD_SPS + C(11)*BIN0905 + C(12)*BIN1008 + C(13)*BIN1011 + C(14)*BIN0514 + C(15)*BINDEC

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	0.001	0.000	70.51418	0.00000
C(2)	4.805	0.762	6.30989	0.00000
C(3)	3.380	0.215	15.71620	0.00000
C(4)	11.292	0.528	21.39179	0.00000
C(5)	12.455	0.536	23.23589	0.00000
C(6)	12.406	0.534	23.22357	0.00000
C(7)	3.361	0.186	18.06078	0.00000
C(8)	3.884	0.643	6.04432	0.00000
C(9)	0.439	0.060	7.28086	0.00000
C(10)	513.817	121.642	4.22402	0.00004
C(11)	-325.357	122.398	-2.65819	0.00839
C(12)	-294.284	118.326	-2.48707	0.01356
C(13)	-215.441	120.425	-1.78900	0.07490
C(14)	-323.457	124.919	-2.58933	0.01021
C(15)	0.530	0.057	9.34928	0.00000

Table F-80: Probability Distribution – Full Requirement Peak Demand Excluding WTMPA – Regression Statistics

Probability Peak Demand

Model Statistics	
Adjusted Observations	251
R-Squared	0.9110
Adjusted R-Squared	0.9057
AIC	9.841
BIC	10.051
Log-Likelihood	-1,576.159
Model Sum of Squares	42,814,843.849
Sum of Squared Errors	4,183,302.01
Std. Error of Regression	133.14
Durbin-Watson Statistic	2.21
Mean dependent var	3,099.04
StdDev dependent var	435.34

Table F-81: Probability Distribution – Full Requirement Peak Demand Excluding WTMPA – Definitions

Probability Peak Demand

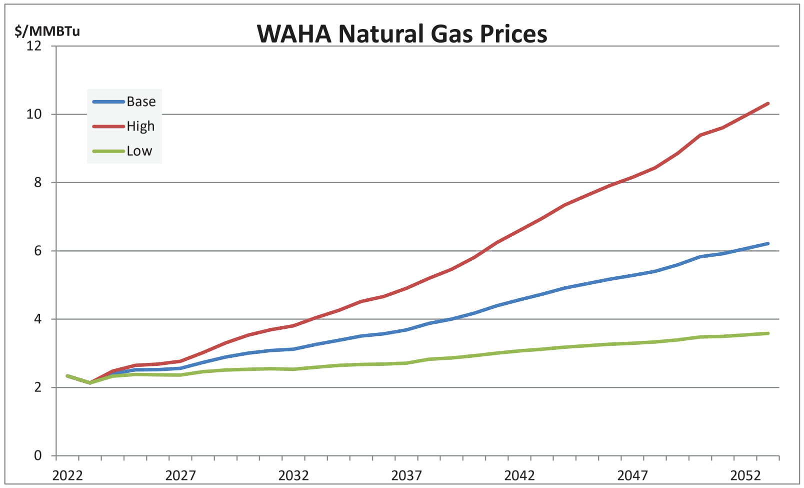
Variable Name	Definition
Peak	SPS full requirement peak demand, excluding WTMPA peak demand
Energy_MA12	12-month moving average of SPS full requirement energy, excluding WTMPA sales
C65_SPS_Apr	April cooling degree days
C65_SPS_May	May cooling degree days
SPS_Avg_Temp_Jun	Peak day average temperature in June
SPS_Avg_Temp_Jul	Peak day average temperature in July
SPS_Avg_Temp_Aug	Peak day average temperature in August
C65_SPS_Sep	September cooling degree days
C65_SPS_Oct	October cooling degree days
HDD_SPS	Service territory heating degree days
Bin1000	Binary variable for October 2000=1, otherwise =0
Bin0905	Binary variable for September 2005=1, otherwise =0
Bin1008	Binary variable for October 2008=1, otherwise =0
Bin1011	Binary variable for October 2011=1, otherwise =0
Bin0915	Binary variable for September 2015=1, otherwise =0
AR(1)	First-order autoregressive term

SPS Forecasted Power/Fuel Prices

Base, High, and Low Forecasts

SPS Forecasted Power/Fuel Prices
Base, High, and Low Forecasts

	Waha Natural Gas ($/MMBtu)			Electricity ($/MWh)		Oil ($/MMBtu)	Coal ($/MMBTu)	
	Base	High	Low	SPP-ON	SPP-OFF	TUC	HAR	TOL
2022	2.34	2.34	2.34	20.48	13.40	1.82	1.61	1.84
2023	2.13	2.13	2.13	18.72	12.81	1.78	1.64	1.87
2024	2.40	2.48	2.33	21.54	15.01	1.77	1.68	1.91
2025	2.51	2.65	2.38	22.54	16.03	1.80	1.72	1.96
2026	2.52	2.68	2.37	23.62	17.55	1.84	1.77	2.01
2027	2.56	2.77	2.36	24.15	17.95	1.88	1.81	2.06
2028	2.73	3.02	2.46	25.02	18.56	1.92	1.86	2.12
2029	2.89	3.31	2.51	25.99	19.47	1.96	1.91	2.17
2030	3.00	3.53	2.53	26.94	20.76	2.00	1.94	2.21
2031	3.08	3.69	2.55	26.97	21.42	2.05	2.00	2.28
2032	3.12	3.80	2.53	26.56	21.31	2.09	2.03	2.32
2033	3.26	4.04	2.59	27.10	22.33	2.14	2.07	2.36
2034	3.38	4.26	2.65	27.23	23.19	2.18	2.12	2.42
2035	3.51	4.52	2.67	27.59	23.46	2.23	2.18	2.49
2036	3.57	4.67	2.68	27.49	23.58	2.28	2.24	2.55
2037	3.69	4.90	2.71	28.28	24.46	2.33	2.30	2.63
2038	3.87	5.20	2.83	29.41	25.90	2.38	2.36	2.69
2039	4.00	5.46	2.86	30.49	26.76	2.43	2.42	2.76
2040	4.18	5.81	2.93	31.49	28.25	2.48	2.48	2.82
2041	4.39	6.25	3.01	33.34	29.57	2.53	2.54	2.90
2042	4.57	6.60	3.07	34.62	30.86	2.58	2.61	2.98
2043	4.73	6.95	3.12	35.51	32.10	2.64	2.68	3.05
2044	4.91	7.34	3.18	36.20	32.95	2.69	2.75	3.13
2045	5.04	7.63	3.22	37.05	34.38	2.75	2.83	3.22
2046	5.17	7.91	3.27	38.03	35.18	2.81	2.90	3.30
2047	5.28	8.16	3.29	38.94	35.90	2.87	2.98	3.39
2048	5.40	8.43	3.33	39.89	37.34	2.93	3.06	3.48
2049	5.59	8.85	3.39	40.06	37.40	3.00	3.14	3.57
2050	5.83	9.39	3.48	40.77	38.72	3.06	3.22	3.67
2051	5.92	9.61	3.50	41.37	39.32	3.13	3.30	3.76
2052	6.06	9.96	3.54	42.42	40.32	3.20	3.38	3.85
2053	6.21	10.32	3.58	43.47	41.32	3.27	3.47	3.95



Demand and Energy Forecast						
	Peak Demand (MW)			Energy (GWh)		
Year	Financial Forecast	Planning Forecast	Low Forecast	Financial Forecast	Planning Forecast	Low Forecast
2022	3,969	4,133	3,709	25,475,845	27,329,919	23,545,944
2023	3,874	4,115	3,528	25,425,620	27,806,276	22,934,842
2024	3,899	4,207	3,507	25,523,530	28,437,432	22,504,125
2025	3,937	4,269	3,484	25,779,795	29,142,514	22,271,129
2026	3,867	4,240	3,363	25,580,420	29,360,490	21,717,416
2027	3,905	4,333	3,376	25,471,918	29,640,113	21,213,941
2028	3,934	4,403	3,363	25,642,615	30,152,730	21,026,343
2029	3,961	4,464	3,343	25,842,979	30,664,557	20,893,456
2030	3,982	4,522	3,308	26,007,388	31,160,661	20,687,294
2031	4,007	4,565	3,332	26,166,304	31,639,736	20,547,144
2032	4,033	4,652	3,312	26,342,128	32,112,771	20,375,791
2033	4,061	4,706	3,322	26,557,979	32,695,224	20,300,016
2034	4,085	4,767	3,307	26,781,145	33,284,261	20,221,534
2035	4,122	4,799	3,295	27,061,409	33,848,773	20,091,776
2036	4,153	4,890	3,298	27,245,226	34,382,271	19,912,222
2037	4,183	4,952	3,324	27,532,561	35,056,498	19,900,664
2038	4,207	4,987	3,278	27,751,721	35,599,380	19,748,257
2039	4,241	5,066	3,270	28,032,684	36,212,303	19,722,193
2040	4,275	5,125	3,285	28,293,573	36,848,387	19,596,808
2041	4,302	5,182	3,283	28,526,079	37,465,743	19,464,632

Input(s):

		Monthly Demand and Energy Forecasts					
		Financial Forecast		Planning Forecast		Low Forecast	
Month	Year	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)
1	2022	2,191,258	3,430	2,331,234	3,605	2,049,878	3,168
2	2022	1,842,251	3,424	1,974,369	3,614	1,705,325	3,144
3	2022	2,114,594	3,248	2,263,947	3,437	1,961,625	2,977
4	2022	1,966,287	3,286	2,113,383	3,491	1,815,357	2,998
5	2022	2,037,485	3,733	2,193,709	3,959	1,875,019	3,375
6	2022	2,205,533	3,824	2,362,660	3,987	2,046,961	3,558
7	2022	2,317,183	3,969	2,470,353	4,133	2,155,300	3,709
8	2022	2,334,958	3,934	2,500,600	4,098	2,159,332	3,680
9	2022	2,125,280	3,789	2,287,627	4,064	1,952,379	3,455
10	2022	2,058,759	3,325	2,218,202	3,520	1,891,136	3,043
11	2022	2,060,533	3,304	2,226,677	3,494	1,888,872	3,024
12	2022	2,221,724	3,424	2,387,158	3,612	2,044,761	3,146
1	2023	2,222,088	3,433	2,405,486	3,661	2,029,754	3,103
2	2023	1,837,597	3,429	2,007,426	3,697	1,655,383	3,088
3	2023	2,113,323	3,251	2,303,640	3,511	1,912,381	2,922
4	2023	1,938,396	3,278	2,119,727	3,538	1,745,983	2,930
5	2023	2,047,514	3,723	2,240,708	3,993	1,847,110	3,317
6	2023	2,197,158	3,726	2,396,713	3,965	1,988,113	3,390
7	2023	2,287,442	3,874	2,482,608	4,115	2,080,890	3,528
8	2023	2,333,822	3,833	2,544,552	4,049	2,117,504	3,491
9	2023	2,117,945	3,730	2,328,357	4,053	1,895,962	3,315
10	2023	2,045,800	3,260	2,256,795	3,525	1,824,996	2,902
11	2023	2,064,739	3,238	2,277,196	3,494	1,838,177	2,893
12	2023	2,219,796	3,359	2,443,068	3,623	1,998,589	3,027
1	2024	2,213,351	3,366	2,445,656	3,678	1,970,104	2,972
2	2024	1,856,917	3,360	2,075,821	3,669	1,632,232	2,946
3	2024	2,098,603	3,175	2,333,893	3,485	1,853,314	2,780
4	2024	1,910,051	3,200	2,138,615	3,515	1,673,608	2,787
5	2024	2,014,253	3,644	2,243,360	3,974	1,768,819	3,187
6	2024	2,231,441	3,747	2,473,301	4,030	1,978,093	3,353
7	2024	2,302,334	3,899	2,537,385	4,207	2,056,799	3,507
8	2024	2,351,704	3,851	2,596,611	4,135	2,087,619	3,459
9	2024	2,143,301	3,787	2,401,592	4,166	1,887,363	3,305
10	2024	2,077,787	3,309	2,334,471	3,645	1,809,957	2,905
11	2024	2,087,922	3,284	2,350,959	3,613	1,819,463	2,871
12	2024	2,235,865	3,404	2,505,769	3,719	1,966,754	2,979
1	2025	2,248,793	3,406	2,522,688	3,753	1,959,407	2,945
2	2025	1,817,758	3,394	2,069,690	3,761	1,558,544	2,919
3	2025	2,127,447	3,205	2,404,983	3,562	1,838,273	2,753
4	2025	1,921,747	3,225	2,187,662	3,596	1,651,822	2,773
5	2025	2,022,740	3,670	2,287,683	4,044	1,743,437	3,139
6	2025	2,272,304	3,793	2,562,932	4,147	1,969,135	3,345
7	2025	2,321,792	3,937	2,587,032	4,269	2,042,474	3,484
8	2025	2,377,029	3,891	2,659,332	4,234	2,072,722	3,437
9	2025	2,176,515	3,827	2,467,168	4,262	1,872,603	3,293
10	2025	2,106,167	3,339	2,404,004	3,728	1,796,934	2,879
11	2025	2,122,772	3,313	2,421,865	3,689	1,807,461	2,846
12	2025	2,264,733	3,431	2,567,476	3,802	1,958,316	2,965

		Financial Forecast		Planning Forecast		Low Forecast	
Month	Year	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)
1	2026	2,276,141	3,434	2,588,505	3,846	1,954,016	2,922
2	2026	1,827,748	3,421	2,107,842	3,842	1,537,350	2,909
3	2026	2,152,625	3,227	2,469,041	3,645	1,827,693	2,722
4	2026	1,938,418	3,247	2,233,552	3,649	1,635,163	2,733
5	2026	2,038,162	3,701	2,342,268	4,112	1,731,941	3,119
6	2026	2,233,820	3,723	2,553,211	4,119	1,908,380	3,243
7	2026	2,269,000	3,867	2,571,539	4,240	1,964,040	3,363
8	2026	2,325,861	3,822	2,646,545	4,197	2,009,040	3,334
9	2026	2,140,292	3,756	2,462,907	4,222	1,806,353	3,175
10	2026	2,069,375	3,264	2,396,481	3,681	1,730,418	2,733
11	2026	2,085,011	3,238	2,424,274	3,664	1,732,376	2,720
12	2026	2,223,967	3,359	2,564,325	3,774	1,880,647	2,846
1	2027	2,184,202	3,362	2,524,842	3,800	1,837,367	2,789
2	2027	1,786,555	3,350	2,105,403	3,804	1,467,204	2,771
3	2027	2,085,669	3,153	2,434,868	3,596	1,727,617	2,593
4	2027	1,902,679	3,173	2,233,049	3,616	1,557,635	2,603
5	2027	2,009,782	3,633	2,343,970	4,082	1,669,315	3,025
6	2027	2,235,346	3,759	2,593,151	4,184	1,872,641	3,227
7	2027	2,333,666	3,905	2,668,806	4,333	1,990,643	3,376
8	2027	2,373,374	3,855	2,724,344	4,276	2,011,701	3,322
9	2027	2,154,791	3,786	2,513,608	4,290	1,784,493	3,171
10	2027	2,076,486	3,289	2,441,681	3,735	1,710,540	2,715
11	2027	2,085,054	3,262	2,443,212	3,728	1,711,973	2,692
12	2027	2,244,313	3,384	2,613,180	3,837	1,872,811	2,814
1	2028	2,207,115	3,386	2,578,452	3,882	1,825,316	2,820
2	2028	1,837,917	3,374	2,180,993	3,884	1,482,837	2,770
3	2028	2,101,298	3,172	2,481,787	3,657	1,709,642	2,572
4	2028	1,906,712	3,194	2,264,250	3,681	1,546,518	2,609
5	2028	2,012,027	3,659	2,371,917	4,169	1,647,294	2,992
6	2028	2,253,517	3,783	2,634,512	4,239	1,871,860	3,202
7	2028	2,332,116	3,934	2,690,279	4,403	1,956,128	3,363
8	2028	2,376,856	3,880	2,746,376	4,360	1,984,880	3,302
9	2028	2,168,468	3,811	2,562,106	4,364	1,779,694	3,161
10	2028	2,089,725	3,309	2,484,127	3,818	1,691,944	2,706
11	2028	2,102,059	3,281	2,504,409	3,782	1,690,272	2,679
12	2028	2,254,805	3,404	2,653,522	3,906	1,839,958	2,815
1	2029	2,240,338	3,408	2,643,005	3,937	1,825,584	2,761
2	2029	1,804,514	3,394	2,166,997	3,942	1,434,762	2,749
3	2029	2,129,160	3,193	2,539,200	3,705	1,703,791	2,570
4	2029	1,921,151	3,214	2,307,449	3,726	1,533,851	2,587
5	2029	2,024,398	3,683	2,406,928	4,172	1,636,106	2,982
6	2029	2,282,145	3,818	2,683,490	4,291	1,866,268	3,196
7	2029	2,338,695	3,961	2,729,170	4,464	1,944,706	3,343
8	2029	2,391,006	3,908	2,781,867	4,386	1,981,994	3,299
9	2029	2,192,701	3,840	2,606,174	4,439	1,762,116	3,137
10	2029	2,113,449	3,330	2,539,232	3,873	1,683,003	2,689
11	2029	2,129,599	3,301	2,562,299	3,847	1,692,686	2,686
12	2029	2,275,823	3,423	2,698,747	3,950	1,828,590	2,773

		Financial Forecast		Planning Forecast		Low Forecast	
Month	Year	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)
1	2030	2,262,694	3,427	2,701,789	3,985	1,808,869	2,755
2	2030	1,815,213	3,415	2,204,981	3,999	1,417,556	2,738
3	2030	2,146,367	3,209	2,582,520	3,773	1,691,902	2,540
4	2030	1,931,278	3,229	2,332,479	3,783	1,509,266	2,582
5	2030	2,034,946	3,706	2,446,227	4,264	1,618,524	3,002
6	2030	2,298,418	3,840	2,730,302	4,373	1,850,796	3,194
7	2030	2,338,272	3,982	2,743,344	4,522	1,924,872	3,308
8	2030	2,395,566	3,930	2,823,242	4,478	1,958,578	3,281
9	2030	2,206,957	3,860	2,637,719	4,514	1,745,008	3,144
10	2030	2,133,215	3,348	2,590,977	3,919	1,659,541	2,664
11	2030	2,150,665	3,320	2,612,549	3,889	1,677,509	2,639
12	2030	2,293,798	3,443	2,754,531	4,009	1,824,871	2,780
1	2031	2,237,348	3,447	2,684,579	4,033	1,771,680	2,763
2	2031	1,834,268	3,435	2,245,979	4,057	1,411,567	2,727
3	2031	2,141,249	3,226	2,608,552	3,823	1,667,831	2,535
4	2031	1,957,644	3,247	2,395,553	3,839	1,510,619	2,550
5	2031	2,064,365	3,728	2,498,844	4,325	1,613,738	2,979
6	2031	2,294,829	3,863	2,756,482	4,449	1,829,837	3,199
7	2031	2,396,714	4,007	2,843,257	4,565	1,948,570	3,332
8	2031	2,436,796	3,951	2,882,120	4,511	1,969,592	3,275
9	2031	2,215,651	3,880	2,697,875	4,534	1,733,130	3,106
10	2031	2,135,030	3,365	2,608,618	3,961	1,635,976	2,663
11	2031	2,144,804	3,337	2,628,193	3,927	1,649,581	2,623
12	2031	2,307,606	3,461	2,789,683	4,038	1,805,022	2,759
1	2032	2,260,434	3,466	2,745,334	4,075	1,758,556	2,746
2	2032	1,887,013	3,456	2,335,325	4,087	1,431,611	2,707
3	2032	2,157,043	3,242	2,647,553	3,843	1,654,120	2,529
4	2032	1,962,107	3,266	2,423,684	3,882	1,482,977	2,549
5	2032	2,067,054	3,751	2,525,945	4,367	1,602,537	2,953
6	2032	2,313,335	3,884	2,791,506	4,499	1,818,070	3,162
7	2032	2,395,408	4,033	2,847,952	4,652	1,917,030	3,312
8	2032	2,440,356	3,973	2,913,735	4,564	1,942,877	3,272
9	2032	2,229,708	3,905	2,720,843	4,597	1,718,296	3,122
10	2032	2,148,920	3,387	2,654,616	4,041	1,637,552	2,651
11	2032	2,162,402	3,359	2,675,374	3,995	1,622,441	2,619
12	2032	2,318,346	3,483	2,830,903	4,108	1,789,723	2,731
1	2033	2,294,953	3,490	2,817,273	4,177	1,763,332	2,719
2	2033	1,855,009	3,478	2,312,795	4,125	1,385,019	2,689
3	2033	2,186,114	3,267	2,705,303	3,922	1,654,489	2,504
4	2033	1,977,740	3,291	2,463,583	3,957	1,481,147	2,532
5	2033	2,080,850	3,778	2,567,518	4,433	1,587,366	2,955
6	2033	2,343,310	3,921	2,849,822	4,554	1,817,604	3,160
7	2033	2,402,991	4,061	2,877,253	4,706	1,900,475	3,322
8	2033	2,455,514	4,004	2,963,304	4,617	1,940,680	3,244
9	2033	2,255,200	3,937	2,782,445	4,678	1,719,352	3,105
10	2033	2,174,301	3,411	2,713,137	4,053	1,629,641	2,622
11	2033	2,191,474	3,383	2,755,715	4,053	1,636,024	2,630
12	2033	2,340,524	3,506	2,887,076	4,165	1,784,887	2,743

		Financial Forecast		Planning Forecast		Low Forecast	
Month	Year	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)
1	2034	2,322,030	3,513	2,869,235	4,186	1,762,126	2,692
2	2034	1,871,032	3,505	2,369,071	4,234	1,384,671	2,674
3	2034	2,208,160	3,287	2,765,619	3,985	1,646,291	2,511
4	2034	1,992,735	3,311	2,512,368	3,993	1,478,757	2,550
5	2034	2,096,434	3,803	2,603,386	4,477	1,581,084	2,924
6	2034	2,364,281	3,946	2,913,530	4,594	1,799,909	3,137
7	2034	2,407,230	4,085	2,919,634	4,767	1,897,865	3,307
8	2034	2,464,740	4,030	2,989,317	4,718	1,913,508	3,252
9	2034	2,274,205	3,962	2,836,490	4,721	1,714,206	3,106
10	2034	2,199,192	3,436	2,764,939	4,154	1,610,116	2,607
11	2034	2,217,624	3,410	2,797,910	4,080	1,641,338	2,598
12	2034	2,363,482	3,533	2,942,761	4,213	1,791,663	2,708
1	2035	2,306,985	3,541	2,874,889	4,278	1,730,393	2,692
2	2035	1,900,081	3,536	2,417,628	4,308	1,378,598	2,678
3	2035	2,213,138	3,314	2,787,080	4,019	1,621,380	2,482
4	2035	2,029,163	3,339	2,577,168	4,075	1,470,612	2,523
5	2035	2,136,100	3,836	2,670,183	4,566	1,578,661	2,927
6	2035	2,370,834	3,980	2,936,599	4,666	1,801,626	3,161
7	2035	2,475,605	4,122	3,020,977	4,799	1,913,923	3,295
8	2035	2,516,058	4,063	3,075,619	4,724	1,938,368	3,262
9	2035	2,293,115	3,995	2,874,239	4,761	1,692,491	3,091
10	2035	2,211,056	3,467	2,806,423	4,215	1,604,935	2,636
11	2035	2,221,783	3,441	2,810,828	4,180	1,589,553	2,590
12	2035	2,387,490	3,565	2,997,141	4,295	1,771,235	2,715
1	2036	2,332,357	3,572	2,931,581	4,334	1,719,572	2,722
2	2036	1,956,331	3,570	2,500,170	4,332	1,385,189	2,678
3	2036	2,230,212	3,342	2,828,007	4,062	1,604,884	2,476
4	2036	2,034,611	3,369	2,610,180	4,095	1,458,837	2,541
5	2036	2,139,904	3,867	2,710,815	4,601	1,558,596	2,951
6	2036	2,389,708	4,008	2,996,240	4,724	1,787,001	3,151
7	2036	2,473,988	4,153	3,040,484	4,890	1,886,462	3,298
8	2036	2,518,989	4,089	3,100,167	4,806	1,908,866	3,232
9	2036	2,306,816	4,023	2,923,573	4,849	1,677,334	3,069
10	2036	2,225,266	3,492	2,853,534	4,268	1,588,358	2,590
11	2036	2,239,411	3,465	2,861,156	4,220	1,594,337	2,581
12	2036	2,397,631	3,589	3,026,363	4,353	1,742,787	2,724
1	2037	2,373,573	3,597	3,017,114	4,377	1,746,995	2,693
2	2037	1,930,222	3,591	2,484,315	4,411	1,346,338	2,665
3	2037	2,265,965	3,370	2,893,362	4,133	1,620,078	2,486
4	2037	2,056,894	3,398	2,649,616	4,165	1,443,250	2,502
5	2037	2,159,779	3,896	2,759,815	4,641	1,551,315	2,905
6	2037	2,425,353	4,047	3,041,471	4,828	1,775,634	3,169
7	2037	2,487,211	4,183	3,076,763	4,952	1,876,971	3,324
8	2037	2,539,705	4,123	3,166,676	4,864	1,920,766	3,233
9	2037	2,337,944	4,059	2,994,257	4,872	1,684,956	3,084
10	2037	2,256,300	3,521	2,934,132	4,318	1,592,872	2,619
11	2037	2,274,206	3,496	2,946,641	4,317	1,593,899	2,602
12	2037	2,425,410	3,619	3,092,336	4,413	1,747,589	2,703

		Financial Forecast		Planning Forecast		Low Forecast	
Month	Year	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)
1	2038	2,401,432	3,626	3,071,301	4,404	1,724,308	2,658
2	2038	1,947,691	3,627	2,534,225	4,436	1,345,771	2,654
3	2038	2,288,418	3,395	2,962,076	4,180	1,604,737	2,473
4	2038	2,072,179	3,422	2,690,390	4,269	1,430,921	2,529
5	2038	2,175,628	3,925	2,796,533	4,750	1,539,964	2,912
6	2038	2,445,620	4,072	3,101,539	4,861	1,780,355	3,133
7	2038	2,490,417	4,207	3,112,646	4,987	1,862,721	3,278
8	2038	2,547,691	4,149	3,190,619	4,957	1,875,021	3,230
9	2038	2,355,771	4,084	3,025,147	4,959	1,658,559	3,105
10	2038	2,280,465	3,546	2,978,215	4,383	1,586,597	2,589
11	2038	2,299,386	3,521	2,994,675	4,366	1,601,347	2,603
12	2038	2,447,023	3,645	3,142,015	4,452	1,737,958	2,666
1	2039	2,386,886	3,652	3,065,278	4,505	1,699,881	2,691
2	2039	1,977,670	3,657	2,598,469	4,523	1,343,198	2,668
3	2039	2,293,428	3,421	2,985,773	4,257	1,589,172	2,506
4	2039	2,108,715	3,450	2,761,350	4,232	1,437,626	2,473
5	2039	2,215,759	3,954	2,877,564	4,764	1,549,985	2,908
6	2039	2,452,329	4,104	3,145,893	4,930	1,765,697	3,172
7	2039	2,558,358	4,241	3,208,005	5,066	1,884,011	3,270
8	2039	2,598,651	4,179	3,263,356	5,004	1,915,342	3,219
9	2039	2,374,656	4,114	3,064,808	5,016	1,656,432	3,070
10	2039	2,292,334	3,575	3,006,677	4,440	1,574,948	2,603
11	2039	2,303,318	3,552	3,031,211	4,374	1,568,216	2,563
12	2039	2,470,580	3,676	3,203,920	4,503	1,737,685	2,683
1	2040	2,417,561	3,683	3,153,974	4,565	1,693,500	2,674
2	2040	2,039,054	3,691	2,711,368	4,583	1,364,674	2,631
3	2040	2,316,583	3,450	3,058,092	4,336	1,577,230	2,460
4	2040	2,120,634	3,482	2,801,951	4,331	1,433,320	2,480
5	2040	2,225,479	3,987	2,895,275	4,827	1,541,939	2,912
6	2040	2,477,505	4,134	3,187,434	4,989	1,758,834	3,143
7	2040	2,563,798	4,275	3,253,935	5,125	1,873,314	3,285
8	2040	2,608,635	4,210	3,288,053	5,057	1,877,564	3,218
9	2040	2,395,322	4,148	3,138,982	5,088	1,651,841	3,087
10	2040	2,313,138	3,606	3,044,233	4,487	1,543,384	2,600
11	2040	2,327,878	3,583	3,071,623	4,460	1,548,411	2,542
12	2040	2,487,987	3,707	3,243,467	4,570	1,732,797	2,691
1	2041	2,455,503	3,714	3,220,118	4,660	1,700,029	2,650
2	2041	2,010,274	3,713	2,681,169	4,700	1,324,671	2,660
3	2041	2,348,210	3,482	3,100,548	4,397	1,566,783	2,455
4	2041	2,138,483	3,512	2,851,016	4,382	1,419,209	2,481
5	2041	2,241,256	4,016	2,946,220	4,873	1,527,401	2,927
6	2041	2,508,650	4,171	3,253,723	5,060	1,748,495	3,154
7	2041	2,571,737	4,302	3,275,923	5,182	1,844,080	3,283
8	2041	2,623,889	4,240	3,365,627	5,096	1,883,433	3,229
9	2041	2,421,137	4,179	3,195,458	5,190	1,643,563	3,061
10	2041	2,339,407	3,631	3,115,492	4,510	1,545,009	2,578
11	2041	2,357,544	3,609	3,153,200	4,487	1,547,764	2,558
12	2041	2,509,990	3,729	3,307,250	4,677	1,714,196	2,695

SPS Generic Unit Cost Data

CT - OPERATIONAL AND COST MODELING DATA

Costs are in 2021$, escalated at 2% per year

Data Description	Values		
Ambient Dry Bulb Temperature, F	Summer, 96	Ann Avg, 59	Winter, 20
Max (100%) Net Capacity MW	200.9	223.5	233.3
75% Net Capacity, MW	150.6	167.5	174.9
50% Net Capacity, MW	100.3	111.6	116.4
Supplemental / Ducts Capacity MW			
Supplemental / Ducts Heat Rate			
HR 100% Loading, BTU/kW-hr (HHV)	10,009	9,846	9,846
HR 75% Loading, BTU/kW-hr (HHV)	10,781	10,349	10,215
HR 50% Loading, BTU/kW-hr (HHV)	12,906	11,986	11,818

Construction Costs k$	$99,500
Fixed O&M Cost, $k/yr	$1,120
Variable O&M Costs, $/MWh	$0.00
On-going Capx, $k/yr	$1,313
Gas Demand, $k/yr	$1,466
EFOR	3.0%
CO2 Lbs/MMBTu	117
Wet or dry cooled	Dry
Supplemental firing	No

2x1 - OPERATIONAL AND COST MODELING DATA

Costs are in 2021$, escalated at 2% per year

Data Description	Values		
Ambient Dry Bulb Temperature, F	Summer, 96	Ann Avg, 59	Winter, 20
Max (100%) Net Capacity MW	601.7	644.8	667.6
75% Net Capacity, MW	421.6	474.7	505.0
50% Net Capacity, MW	256.6	293.1	315.5
30% Net Capacity, MW	158.0	178.9	190.8
Supplemental / Ducts Capacity, MW	169.3	167.3	164.1
Supplemental / Ducts Heat Rate, BTU/kW-hr	10,000	10,000	10,000
HR 100% Loading, BTU/kW-hr (HHV)	6,258	6,246	6,287
HR 75% Loading, BTU/kW-hr (HHV)	6,731	6,598	6,583
HR 50% Loading, BTU/kW-hr (HHV)	6,757	6,637	6,654
HR 30% Loading, BTU/kW-hr (HHV)	7,873	7,637	7,582

Construction Costs k$	$596,250
Fixed O&M Cost, $k/yr	$5,400
Variable O&M Costs, $/MWh	$1.22
On-going CapX, $k/yr	$5,150
Gas Demand, $k/yr	$16,551

EFOR	3.0%
CO2 Lbs/MMBTu	117
Wet or dry cooled	Dry
Supplemental firing	Yes

June 30, 2021

VIA HAND DELIVERY
Ms. Melanie Sandoval, Records Bureau Chief
New Mexico Public Regulation Commission
P.O. Box 1269
Santa Fe, NM 87504-1269

Re: Case No. 21-00169-UT *In the Matter of Southwestern Public Service Company's 2021 Integrated Resource Plan*

Dear Ms. Sandoval:

In accordance with the Uncontested Comprehensive Stipulation in Case No. 19-00170-UT, Southwestern Public Service Company is filing its Tolk Analysis that will be incorporated into its Integrated Resource Plan to be filed July 16, 2021.

Please date stamp one copy of the referenced document and return to SPS. If you have any questions, please contact me at (806) 378-2115.

Yours very truly,

/s/ Mario Contreras
Mario Contreras,
Manager Rate Cases

Enclosures

2021
Tolk Analysis

Southwestern Public Service Company

June 30, 2021

Contents

Executive Summary

Tolk Generation Station ("Tolk") Units 1 and 2, which are located in West Texas and use coal fuel, rely upon the Ogallala Aquifer for generation and cooling water, and the aquifer is in an irreversible decline. If the Tolk Units are dispatched year-round on a purely economic energy basis without accounting for the long term capacity value of the Tolk Units or assigning an opportunity cost to the use of the water supply, aquifer productivity is projected to run out and become uneconomical by the mid 2020's – necessitating the early retirement of the Tolk Units. In New Mexico Base Rate Case No's. 17-00255-UT and 19-00170-UT, SPS presented economic analyses supporting the combination of (1) a change to summer-only economic dispatch of the Tolk Units and (2) a 2032 retirement date. In those prior cases and this current analysis, the objective was, and continues to be, to keep the approximately 1,000 megawatt ("MW") of firm capacity for as long as possible and at the same time maintain the voltage stability and reliability needs of the SPS system while minimizing the cost impact to its customers.

The Uncontested Comprehensive Stipulation ("Stipulation") from New Mexico Case No. 19-00170-UT ultimately set the date of abandonment and retirement for generating purposes of the Tolk Units at December 31, 2032. Further, in the Stipulation, SPS agreed to conduct an analysis by June 2021 of Tolk abandonment and potential means of replacement ("Tolk Analysis"). This submittal provides the Tolk Analysis.

The Tolk Analysis continues to support summer-only seasonal operations and a 2032 retirement date as the optimal economical solution for serving SPS's customers.[1] Maintaining the existing depreciated Tolk Units through 2032 is a low-risk option to ensure SPS can reliably and economically serve customers and meet its planning reserve margin requirements. In the absence of the Tolk Units, (1) new replacement firm capacity resources will be required and (2) as seen in the results of the recent request for information ("RFI"), there is a high uncertainty whether SPS could acquire the necessary resources in the timeframe required, and if so, at what cost. Finally, as demonstrated during the recent Winter Storm Uri, the Tolk Units continue to provide important and valuable reliability and fuel diversity benefits to the SPS system.

As an economical, low-risk, and reliable solution, the Tolk Analysis concludes that the best approach for customers is to continue seasonal operation of the Tolk Units and for the retirement date of the Tolk Units to remain at December 31, 2032. This Tolk Analysis is not, however, intended to be a final conclusion; SPS will continue to review and consider what options will most benefit customers.

---

[1] During a system emergency in a non-peak month, SPS may convert the generators to generation mode and operate them during the system emergency as was done during Winter Storm Uri in February 2021.

Section 1: Introduction

SPS presents its 2021 "Tolk Analysis" evaluating the economically optimal future operation and retirement dates of the two coal-fired Tolk Units. The 2021 Tolk Analysis represents over 12 months of robust analysis, including: (1) consideration of the results of the RFI, which was an all-source solicitation; and (2) evaluation of 162 different scenarios and sensitivities. Moreover, the Tolk Analysis was conducted pursuant to the oversight of an Independent Evaluator ("IE"). SPS actively sought feedback from interested parties throughout the Tolk Analysis by hosting a series of 'Technical Conferences' specific to the Tolk Analysis in addition to and in parallel with SPS's 2021 Integrated Resource Plan ("IRP") public advisory process.

Section 2: Background

The Tolk Units rely exclusively on groundwater from the Ogallala Aquifer for generation and cooling water, and the portion of the Ogallala Aquifer underlying Tolk is in an irreversible decline. The part of the aquifer that includes the Tolk wellfield is thin relative to other areas of the aquifer, and it is being depleted to support agricultural, municipal, and industrial uses. Because groundwater extraction for these uses significantly exceeds the aquifer recharge rate, the saturated thickness of the aquifer has declined by over 300 feet in some areas of the Texas Panhandle and will ultimately cause the aquifer productivity to decline to a point where it will be uneconomical to recover water needed to run the two coal-fired steam generating units.

If the Tolk Units continue to operate unconstrained (i.e., 12 months of the year), aquifer productivity is predicted to become uneconomical by the mid 2020's. In New Mexico Base Rate Case Nos. 17-00255-UT and 19-00170-UT, SPS presented economic analyses supporting a change to the operating parameters and retirement dates of the Tolk Units. SPS's analyses supported preserving the retirement dates of the Tolk Units until 2032 by restricting the units to generate only during the high-load summer months, or during system emergency situations**.** Because of the reduced operations and retirement of the Tolk units, SPS had to address voltage stability and reliability needs on the transmission system. SPS's solution to address this need was to install the necessary equipment to allow the two generators to operate as synchronous condensers at the Tolk Station site. This solution is reasonable and necessary to assure the continued stability and reliability of the SPS transmission system.

The Stipulation in Case No. 19-00170-UT ultimately set the date of abandonment and retirement for generating purposes of Tolk at December 31, 2032 and SPS agreed to conduct an updated robust analysis by June 2021 of Tolk abandonment and potential means of replacement.

Section 3: Tolk Analysis Overview

The Stipulation in Case No. 19-00170-UT requires SPS to:

> *"Submit a robust analysis of Tolk abandonment and potential means of replacement by June 2021… The Tolk Analysis shall include evaluation of (i) the type, technical characteristics, and cost of the resources needed or available to replace the capacity provided by Tolk, (ii) the economically optimal (in terms of the public interest) abandonment dates for Tolk, and (iii) the impact on customer rates of multiple abandonment scenarios based on the present value revenue requirements considering SPS's integrated resources. SPS also commits to running at least one scenario in which all of SPS's coal-burning units are retired or replaced before 2030."*

As further detailed in the Stipulation in Case No. 19-00170-UT, the Tolk Analysis requires: (1) SPS to host two technical conferences, (2) a review by an Independent Evaluator, (3) replacement resources priced based on an RFP or RFI, and (4) the value of reselling the water rights.

Section 4: Technical Conferences

The Stipulation in Case No. 19-00170-UT stated:

> *"In the IRP public input process, and prior to filing the IRP, SPS shall hold two technical conferences located in either Santa Fe or Albuquerque, NM. The first technical conference will be for SPS to present and solicit feedback on the basic parameters and approach of its analysis. The second technical conference will be for SPS to provide and solicit feedback on the preliminary conclusions of its analysis."*

The COVID-19 global pandemic prevented SPS from holding the technical conferences in-person. Instead, the technical conferences were held virtually over video call. Due to the volume and sequential nature of the materials being presented, SPS split the first "technical conference" into four separate sessions. The dates and agenda items of the technical conferences are summarized below in Table 1. The complete presentations are provided in Appendix A and, at the time of filing, the presentations are also available on Xcel Energy Inc.'s company website:

https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/2022_new_mexico_integrated_resource_plan

Table 1. Technical Conferences:

Date	Conf.	Session	Location	Agenda Items
06/18/2020	1	1	Virtually	• General approach of the Tolk Analysis • Request for Proposal ("RFP") to acquire the services of an IE • Draft RFI to obtain pricing of replacement resources • Outline of the scenarios SPS is proposing to evaluate
09/01/2020	1	2	Virtually	• Prior and Future Technical Conferences • Updates from Prior Technical Conference 1. Independent Evaluator 2. RFI for generating resources • Encompass – Production Cost Modeling Software • Responses to Parties Comments and Questions 1. SPS Load Forecast Update 2. Sierra Club Modeling Questions
10/23/2020	1	3	Virtually	• Harrington Station – Modeling Assumptions
02/08/2021	1	4	Virtually	• Recap prior technical conferences • Tolk Analysis – Final proposed retirement dates and operating scenarios • Replacement Resources in the Encompass Model • Critical Modeling Parameters / Sensitivities • Value of Tolk water rights • Summary of 1st Technical Conference • Final review of questions previously submitted by Sierra Club
04/19/2021	2	1	Virtually	• Introduction • Tolk Analysis Overview • SPS System Overview • Conclusion 1: Replacement Resources • Conclusion 2: Preliminary Results • Final Review

Section 5: First Technical Conference

Section 5A: Introduction

The first two sessions of the First Technical Conference introduced SPS's general approach to the Tolk Analysis, including potential operating and retirement scenarios, the appointment of the IE and the issuance of the RFI. The 3rd Session addressed the decision to model the Harrington Generating Station ("Harrington") Units operating on natural gas beyond 2024 and the 4th Session finalized critical modeling parameters, such as the scenarios and sensitivities to be evaluated.

Section 5B: 1st & 2nd Sessions of the First Technical Conference

The agenda items covered in the 1st and 2nd Sessions were split to allow time for interested parties to provide feedback on (1) acquiring the services of the IE and (2) the issuance of an RFI to acquire pricing for replacement resources.

Section 5B.1: General Approach

The Tolk Analysis is a Present Value Revenue Requirement ("PVRR") Analysis using the Encompass production cost modeling software. The Tolk Analysis incorporates the system-wide costs of multiple operating and retirement dates for the Tolk Units (scenarios), with each scenario incorporating an optimized expansion and generator replacement plan. The type, technical characteristics, and cost of replacement generation was the result of an RFI process. Finally, the Tolk Analysis was overseen by Guidehouse (formerly known as Navigant Consulting), an independent third-party evaluator.

The Tolk Analysis is described in more detail in subsequent sections – at a high level, the Tolk Analysis incorporated the following sequential steps:

1. Appoint the IE
2. Issue the RFI for replacement resources
3. Update EnCompass inputs and assumptions
4. Incorporate the proposals from the RFI process
5. Conduct the PVRR analysis in EnCompass
6. Present preliminary results at the 2nd Technical Conference
7. Publish Final results and conclusions

Section 5B.2: Independent Evaluator

A competitive RFP was issued to acquire the services of the IE. A draft copy of the RFP was presented during the 1st Session of the First Technical Conference. Interested parties were given 7 days to provide comments. The RFP was issued on July 6, 2020, a pre-bid meeting was held with prospective bidders two days later, and proposals were due on July 20, 2020. A copy of the final RFP can be found in Appendix B. After evaluating the proposals, SPS recommended awarding the contract to Guidehouse. Before awarding the contract, SPS solicited feedback from interested parties by hosting a virtual meeting on August 9, 2020. A copy of the recommendation presented during the August 9, 2020 meeting can be found in Appendix C. There were no objections or concerns expressed regarding moving forward with Guidehouse. Hearing no objections and after receiving concurrence from NMPRC staff, Guidehouse was formally appointed as the IE for the Tolk Analysis. A copy of Guidehouse's final report can be found in Appendix D.

Section 5B.3: RFI Issuance

A draft copy of the RFI was presented during the 1st Session of the First technical conference. The presentation summarized SPS's intent to issue an all-source solicitation for replacement generating resources that considered all ownership structures including, but not limited to, purchased power agreements, build-own-transfers, and company self-built facilities. The RFI required bidders to provide information necessary to accurately model the proposed resources – including, but not limited to; pricing, technical characteristics, generator output, and commercial operation date. SPS solicitated comments from interested parties to be provided within 28 days of this 1st Session of the First Technical Conference.

A 'near-final' copy of the RFI was presented during the 2nd Session of the First Technical Conference. The near-final copy of the RFI incorporated a review by Guidehouse, and interested parties were given an additional five days to provide comments before the RFI was issued.

The RFI was subsequently issued on September 9, 2020 with proposals due within 60 days. A copy of the final RFI is included in Appendix E.

A bidders meeting was held on September 21, 2020 to provide potential respondents with an overview of the RFI process, instructions for submitting proposals, and to answer any questions from bidders. Upon receipt of the proposals, SPS scheduled meetings with each bidder to discuss and clarify their proposals.

Finally, a standalone email account was established for bidders to submit their proposals and to ask any questions. Guidehouse was copied on all emails received and sent from this email account to ensure fairness and consistency.

Section 5B.4: EnCompass Production Cost Model

At the time of commencing the Tolk Analysis, SPS had recently transitioned from the Strategist production cost model to a new production cost model, EnCompass which is owned by Anchor Power. Xcel Energy Inc. has a licensing agreement with Anchor Power for use of the model.

During the 1st Session of the First Technical Conference, SPS received several questions regarding the EnCompass software. In response, SPS provided an overview of EnCompass during the 2nd Session of the First Technical Conference. The presentation (found in Appendix A) included the following agenda items: (1) the impetus for change, (2) software options, identification and evaluation, (3) model features, and (4) key stakeholder issues addressed.

Section 5B.5: Other Agenda Items

Finally, during the 1st Session of the First Technical Conference SPS presented proposed operating parameters and retirement dates (scenarios) for the Tolk Analysis. After incorporating feedback from interested parties, the list of scenarios was subsequently updated, and the final list of scenarios was presented during the 4th Session of the First Technical Conference (see section 5D.1).

During the 2nd Session of the First Technical Conference SPS responded to questions and requests from the previous session. SPS's responses to these questions can be found in the complete PowerPoint presentations found in Appendix A.

Section 5C: 3rd Session of the First Technical Conference

During the 3rd Session of the First Technical Conference, SPS addressed an October 2020 signed order with the Texas Commission of Environmental Quality ("TCEQ") resolving National Ambient Air Quality Standards ("NAAQS") compliance issues at Harrington. The TCEQ signed order requires Harrington to cease burning coal by end of year 2024. While the conversion of the Harrington Units to operate on natural gas is outside the scope of the Tolk Analysis, for the purposes of evaluating all scenarios in which the Harrington Units continue to operate beyond 2024 (i.e., Scenario 1 through Scenario 5) SPS assumed the Harrington units would be converted to natural gas at the end of 2024.

Section 5D: 4th Session of the First Technical Conference

The primary focus of the 4th Session of the First Technical Conference was to finalize the critical modeling parameters of the Tolk Analysis, including (1) the operating and retirement scenarios, (2) critical modeling parameters and modeling sensitivities, and (3) the value of Tolk water rights.

Section 5D.1: Operating & Retirement Scenarios

SPS initially presented five different operating and retirement scenarios during the 1st Session of the First Technical Conference. After incorporating comments from interested parties, SPS presented six final operating and retirement scenarios during the 4th Session. The final six scenarios are as follows:

- **Scenario 1 – Annual Economic Dispatch**
    - Summer only economic dispatch throughout 2021
    - Annual economic dispatch thereafter
    - Both Tolk units retire at end of economically available water - EOY 2025
    - Harrington converted to gas EOY 2024
- **Scenario 2 – Summer Only Economic Dispatch**
    - Summer only economic dispatch 2021 and beyond
    - Both Tolk units retire at end of economically available water - EOY 2032
    - Harrington converted to gas EOY 2024
- **Scenario 3 – Earliest Retirement of Tolk Units**
    - Summer only economic dispatch 2021
    - Annual economic dispatch thereafter
    - Both Tolk units retire EOY 2023
    - Harrington converted to gas EOY 2024
- **Scenario 4 – Staggered Retirement of Tolk Units**
    - Summer only economic dispatch 2021

  - Annual economic dispatch thereafter
  - Unit 1 retires EOY 2023
  - Unit 2 retires at end of economically available water - EOY 2031
  - Harrington converted to gas EOY 2024

- **Scenario 5 – Staggered Retirement of Tolk Units & Seasonal Operations**
  - Summer only economic dispatch
  - Unit 1 retires EOY 2023
  - Unit 2 retires EOY 2032
  - Harrington converted to gas EOY 2024
- **Scenario 6 – Earliest Retirement of Tolk & Harrington Units**
  - Tolk - Summer only economic dispatch 2021
  - Tolk - Annual economic dispatch thereafter
  - Harrington – Annual economic dispatch in all years
  - All Tolk and Harrington Units Retire EOY 2023

Section 5D.2: Critical Modeling Inputs & Modeling Sensitivities

During the 4th Session of the First Technical Conference, SPS presented an overview of critical modeling inputs including, (1) natural gas price forecast, (2) market energy price forecast, and (3) demand and energy forecast. As each of these inputs can have a significant impact on the Tolk Analysis, SPS presented proposals for sensitivity analyses.

Natural Gas Price Forecast

The price of natural gas is a significant input into the planning model. SPS uses a combination of market prices and fundamental price forecasts, based on multiple highly respected, industry leading sources, to calculate monthly delivered gas prices. As the foundation of the gas price forecast, Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange ("NYMEX") futures prices) and long-term fundamentally based forecasts from Wood Mackenzie, IHS Markit, and S&P Global. The forecast is fully market-based for the first few years, then transitions into blending the four sources to develop a composite forecast. The Henry Hub forecast is adjusted for regional basis differentials and specific delivery costs for each generating unit to develop final model inputs.

Gas Forecast Sensitivity

SPS conducted low and high gas price forecast sensitivity analyses. 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.

Market Energy Price Forecast

In addition to resources that exist within SPS's service territory, SPS has access to a regional market located outside its service territory. SPS is a member of the Southwest Power Pool, which operates as a consolidated balancing authority and dispatches all available generation resources within its boundaries. This consolidated dispatch allows SPS access to energy resources outside SPS's service territory for energy purchases, as well as the opportunity to sell from its generating sources to other market participants.

SPS uses a simple average of long-term on-peak and off-peak implied heat rate forecasts provided by Wood Mackenzie, S&P Global, and IHS Markit for Southwest Power Pool South Hub. The implied heat rates, denominated in million British thermal units/megawatt-hour ("mmBtu/MWh"), are then multiplied by SPS's long-term natural gas price forecast to convert the implied heat rate values into energy prices. This process is repeated for all months, distinguishing between on and off-peak prices, through the end of the modeling period.

Market Price Forecast Sensitivities

SPS's market price forecast is dependent on the gas price forecast used. As such, the market price forecast was adjusted with the low and high gas sensitivity analyses.

Demand and Energy Forecast

Projections of future energy sales and coincident peak demand are fundamental inputs into SPS's resource need assessment. SPS forecasts retail energy sales and customers by rate class for each jurisdiction. Retail coincident peak demand is forecasted in the 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 on a monthly basis and uses monthly historical data to develop the customer, energy sales, and coincident peak demand forecasts. Energy sales are forecasted at the delivery point and peak demand is forecasted at the generating source.

Demand and Energy Sensitivity Analysis

Development and use of different energy sales and demand forecasts for planning future resources is an important aspect of the planning process. SPS conducted sensitivity analyses using a high and low forecast. The high and low forecasts 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.

Note: The methodology described above for calculating the 'base' load case forecast is largely used for financial planning purposes and is referred to throughout the Tolk Analysis as the financial load forecast. Despite continued growth in oil and gas developments in the New Mexico portion of the Permian basin and due to the volatility of the industry, the financial load forecast incorporates only a modest amount of projected oil and gas load growth. The 'high' load case forecast, referred to throughout the Tolk Analysis as the planning load forecast, represents a more accurate projection of SPS's capacity position if oil and gas load continues to increase. For the purposes of resource planning, the planning load forecast is predominately used to ensure SPS has enough resources to reliably serve customers.

Section 5D.3: Tolk Water Rights Valuation

SPS presented an overview of the Tolk wellfield, including the basics of Texas groundwater law and valuation practices during the 4th session of the First Technical Conference. The presentation went on further to highlight the critical assumptions that would be required to be able to provide a representative valuation of the Tolk water rights. Some of these assumptions include the exclusion of portions of the wellfield with saturated thickness less than 40 feet (the limit of economic recovery), consideration of probable buyer needs which may negatively influence the purchase price, including the need for a conveyance system from the Tolk wellfield to the place of eventual use, and the assumption of the amount of time between now and when the future water transaction would occur to account for subsequent depletion. Projections of the rate of depletion have been consistent over several years of analyses. Two alternative valuation methodologies were described. The first relies on a depreciation study commissioned annually by the High Plains Underground Water District No.1. This study is used by local landowners to track depreciation of water values for tax purposes and specifically identifies District-wide water value. The second method requires retention of a local expert in water valuation to offer an opinion about the potential value of the Tolk water rates based on recent local real estate transactions.

Section 6: Second Technical Conference

Section 6A: Introduction

SPS presented the preliminary conclusions from the Tolk Analysis during the Second Technical Conference, held on April 19, 2021. Although the results presented in the Tolk Analysis may differ from the preliminary results presented in the technical conference, the conclusions are consistent between the two.

Section 6B: Final Conclusions

The primary and secondary conclusions of the Tolk Analysis are summarized below and discussed in detail throughout the remainder of this section.

Primary Conclusion – Retirement of the Tolk Units

The results of the Tolk Analysis continue to support seasonal operations and a 2032 retirement date for the Tolk Units.

Secondary Conclusion – The Acquisition of Economic Energy Resources Proposed in the RFI

Regardless of the operation and retirement dates of the Tolk Units, the Tolk Analysis provides indication that proposals received from the RFI process could potentially provide economical energy savings. However, as described in detail in Section 6E, potential energy savings are highly dependent on critical modeling inputs and external economic drivers, that currently possess a high level of uncertainty and risk. Because of this uncertainty, SPS is not recommending the acquisition of new resources at this time and will continue to monitor developments in these areas.

Section 6C: SPS System Overview

To provide reliable service, all electric utilities must have more capacity available than the projected peak load to allow for system contingencies, including generating unit or transmission outages and potential increases in actual load. The available capacity in excess of the projected peak load is referred to as the "planning reserve margin." Planning reserve margin requirements are frequently specified by the group of interconnected utilities to which the utility belongs. SPS is a member of the Southwest Power Pool Regional Transmission Organization, which currently requires each member to have a planning reserve margin of at least 12% of its peak demand forecast, pursuant to Southwest Power Pool's rules for net planning capability.

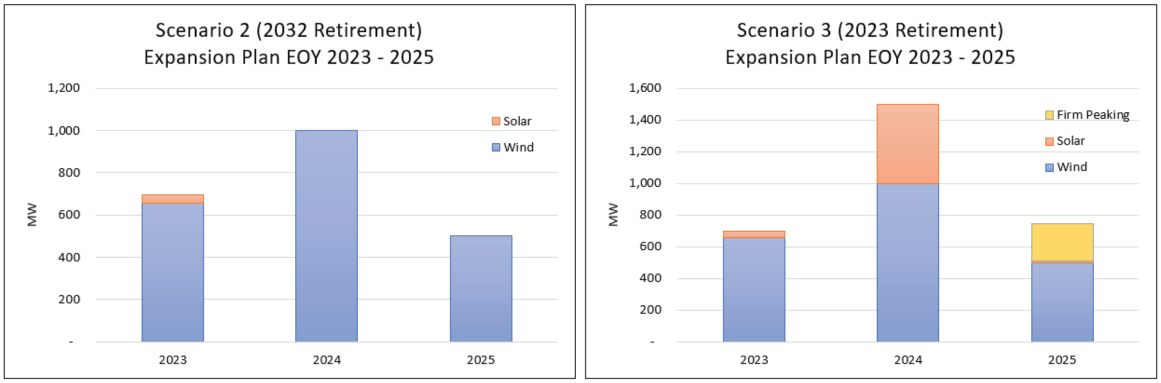
Depending on future load growth, SPS currently has adequate capacity (resources) to meet its planning reserve margin until the late 2020's to early 2030's. The early retirement of the Tolk Units would create an immediate capacity need, requiring SPS to acquire new capacity providing resources. Renewable energy resources, such as wind and solar generation, can count a percentage of their nameplate capacity towards SPS's planning reserve margin and could potentially fulfill SPS's capacity need in the short-term. However, as existing firm and dispatchable resources retire, SPS will almost certainly be required to acquire generating resources that can serve load in all hours. These additional resources could include battery storage or traditional thermal resources, such as combustion turbines, combined cycle generation, or new generation technology not yet identified.

Section 6D: Modeling Replacement Resources

EnCompass will not necessarily model replacement of the capacity and energy attributes of the Tolk Units with like-in-kind generation. Instead, the model will optimally create an 'expansion plan' for each scenario based on the resource need, for example, replacing the Tolk Units could consist of a combination of solar, wind, battery storage, combustion turbines etc. – all at different locations, with different in-service dates. While the optimized expansion plan must ensure SPS has enough resources to meet the planning reserve margin, the model may also select additional resources purely for economical energy (i.e., even when there is no capacity need).

Considering the EnCompass model algorithm ensures SPS meets its planning reserve margin, the early retirement of over 1 gigawatt ("GW") of generation (i.e., The Tolk Units) could be expected to produce a substantially different optimized expansion plan than the continued operation of Tolk Station (i.e., there is a greater 'need' in one scenario). For reference, the SPS 2021 peak load is projected to be 4.1 GW. One GW represents approximately 25% of SPS's capacity reserve requirement. However, as demonstrated below in Figure 1, the near-term optimized expansion plans for a 2032 (scenario 2) and a 2023 early retirement of the Tolk Units (scenario 3) are similar. For example, both scenarios add 2,158MW of new wind generation during the three-year period. In fact, all scenarios, result in the addition of significant amounts of renewable generation between 2023 and the end of 2025. As shown in Figure 1, despite the addition of renewable generation, the early retirement of the Tolk Units also results in the addition of a new combustion turbine in 2025.

Figure 1. Expansion Plans for Scenario 2 and Scenario 3 EOY 2023 – 2025 (financial load forecast, base case, $400/kW)



In short, the Tolk analysis demonstrated that, regardless of the operation and retirement of the Tolk Units, under the inputs and assumptions modeled, the proposals received in the RFI could provide economic energy savings. To put it another way, a portion of the renewable generation included in each scenario's expansion plan is being added for economic energy benefits, not just to fulfill a capacity need in the absence of Tolk.

However, as described below, the potential energy savings associated with the acquisition of economic renewable energy is highly dependent on critical modeling inputs and external economic drivers that are currently uncertain.

Section 6E: Critical Modeling Inputs & External Economic Drivers

The potential economic energy savings of the proposals received in the RFI are highly dependent on certain critical modeling inputs and external economic drivers that are currently uncertain. For example, it is no coincidence that each scenario included significant amounts of new renewable generation, particularly wind, between the end of 2023 and 2025. Currently, both wind and solar generation benefit greatly from federal renewable tax credits that are scheduled to expire, or step-down, by the end of 2025. Expiring federal renewable tax credits are discussed in more detail in Section 6E.1.

In addition, the current cost of interconnecting new generation within the Southwest Power Pool footprint is extremely high. Of great significance, many proposals received in the RFI did not include the full cost of interconnecting the proposed new generation, consequently SPS had to assign different levels of network upgrade costs to new generation that required a Generator Interconnection Agreement ("GIA"). Any potential economic energy savings are highly dependent on the network upgrade costs assigned to the project. Uncertainty in network upgrade costs are discussed in more detail in Section 6E.2.

However, before discussing critical modeling inputs and external economic drivers in more detail, it is also worth considering the logic of production cost modeling when calculating economic energy savings. For example:

- Economically selected resources are not necessarily economical in all years, an economically selected resource may result in increased system costs for several years – only providing economical savings in future years.
- EnCompass's logic does not include a benefit-to-cost ratio threshold – for example, EnCompass could select a resource that is forecasted to lower overall energy costs by a relatively modest amount, even if the projects requires a multi-year, multi-million-dollar commitment.
- EnCompass evaluates system-wide costs over a long-term planning horizon, not necessarily the immediate impact to SPS's ratepayers.

To mitigate customer risk, SPS will consider and evaluate factors such as these when conducting any potential future resource acquisition analysis.

Section 6E.1: Expiring Renewable Tax Credits

Whether or not the Federal government decides to extend Renewable Tax Credits will fundamentally change the optimized expansion plan for each scenario. For example, new wind resources currently qualify for a 60% production tax credit ("PTC") through the end of 2025. If PTC's are not extended, wind projects placed in-service after 2025 would no longer receive a PTC. SPS estimates the expiration of PTCs would increase the levelized cost of new wind projects by up to $15/MWh, resulting in a sudden and sharp increase in the price of wind generation. For the purposes of the Tolk Analysis, SPS assumed renewable tax credits would expire, or step down, based on the current schedule. This assumption generally resulted in the early acquisition of renewable generation, particularly wind, in each of the expansion plans. In short, the model selected wind generation before the end of 2025 as it would become significantly more expensive after PTC's expire. If Renewable Tax Credits are extended, or replaced, the optimized expansion plan may delay the acquisition of new renewable generation.

Section 6E.2: Generator Interconnection Agreement – Schedule & Cost Uncertainty

As described in SPS witness Bennie F. Weeks' rebuttal testimony in New Mexico Case No. 19-00170-UT, in recent years, the Southwest Power Pool has been overwhelmed by the large number of new generators being proposed in the region. This has caused a long delay in studying and finalizing generator interconnection agreements ("GIAs"). To quantify this delay, at the time of filing the Tolk Analysis, the Southwest Power Pool is still evaluating the 2017-01 Definitive Interconnection System Impact Study ("DISIS").

In addition to the long delays, as described in SPS witness Ben R. Elsey's direct testimony in New Mexico Case No. 20-00143-UT transmission costs could potentially be extremely expensive and [new] resources could have significant cost uncertainty and schedule uncertainty.

These concerns are highlighted in the 2017-01 DISIS, for example, the 1st Phase of the Study included 25 projects totaling 3,795MW of new generation in Group 6 (Group 6 incorporates the South Texas Panhandle and New Mexico). These projects were assigned a total of $3.5B of network upgrades, or an average of $934/kilowatt ("kW"). For comparison, developers 'typically' include up to $100/kW for network upgrade costs, and the overnight construction cost of a new wind project or solar project is approximately $1,500/kW and $1,000/kW, respectively.

Presumably because of the extremely high interconnection costs assigned, approximately 1,000MW of this new generation subsequently dropped out of the 2017-01 study before the 2nd Phase of the study. Despite the loss of these projects, the remaining projects were still assigned, on average, $934/kW.

On May 14, 2021 the remaining projects were required to pay a 20% deposit to remain in the 2017-01 DISIS. Of the 3,795MW of new generation originally submitted, only a single 200MW project remains in the queue.

The current network upgrade costs being assigned to developers is, at best, challenging and at worst, cost prohibitive. These issues were reflected in the proposals received in the RFI process. No proposals requiring a new GIA included close to the level of costs currently assigned in the 2017-01 DISIS, and multiple proposals did not include any network upgrade costs. As a result, SPS assigned various indicative network upgrade costs to all proposals that require a new GIA. SPS conducted sensitivity analyses, applying, $200/kW, $400/kW, and $600/kW network upgrade costs to all proposals that required a new GIA (note: all sensitivities incorporated significantly less than the $934/kW assigned in the 2017-01 DISIS). Proposals that were not assigned network upgrade costs were (1) proposals with an existing GIA or (2) 'Build-Transfer' proposals at SPS's existing generator locations. The latter were modeled as 'surplus interconnection' projects or 'generator replacement' projects. In addition, the network upgrade costs described above were applied to all wind, solar and combined cycle resources in future years – including generic replacement resources beyond 2025. Transmission network upgrade costs were not assigned to future combustion turbines or battery energy storage, on the assumption these resources would be installed at the site of retiring SPS generators as generator replacement projects,

Section 6E.3: RFI Proposals vs Generic Cost Assumptions

SPS leveraged the results of the RFI for new resources through 2025. Thereafter, SPS utilized 'generic' pricing for the cost of new resources. The average cost of proposals received from the RFI were used as a baseline for the cost of generic resources. Using an average cost as a baseline, of course, resulted in some of the proposals received in the RFI being lower cost than the generic cost of new generation. All else-being-equal, the lower cost proposals, with in-service dates before 2025 are more favorable than the higher cost generic resources. Again, favoring the early acquisition of additional resources.

Section 6E.4: Feasibility of RFI Proposals

The long delay in finalizing GIA not only creates cost uncertainty, but also casts doubt on whether all the proposals included in the optimized expansion plans could feasibly be constructed in the timeframe necessary (for example, Scenario 3 assumes a EOY 2023 retirement for both units), or if the project will even proceed at all. For example, SPS received several proposals that had not applied for a new GIA. Considering the several year process for acquiring a new GIA, it is unlikely these proposals will be commercially operational in the timeframe required. Likewise, SPS received several proposals that were included in the 2017-01 DISIS, however, as described in Section 6E.2, all but 200MW of the original 3,795MW of new projects have withdrawn from the queue and are unlikely to be commercially operational in the timeframe required. Despite these very real challenges, for the purposes of the Tolk Analysis, SPS included all projects based on the commercial operation dates submitted in the proposal. Although it is highly unlikely many of the proposals evaluated will be able to meet the necessary commercial operation date, taking this approach allowed SPS to stress test the economic viability of the early retirement of the Tolk units.

Section 6E.5: Secondary Conclusion – The Acquisition of Economic Energy Resources Proposed in the RFI Summary

Regardless of the operation and retirement dates of the Tolk Units, each scenario's optimized expansion plan added substantial amounts of new renewable generation between end of years 2023 and 2025. This large-scale acquisition of new generation was, in part, caused by the modeling inputs and assumptions SPS used for the Tolk Analysis. For example, critical modeling assumptions, such as expiring PTCs/ITCs, generic costs assumptions (both present and future) and the cost of network upgrades (both present and future), fundamentally impact the timing and acquisition of additional resources in each scenario's optimized expansion plan.

Although it is unlikely all the inputs and assumptions used for the analysis are ultimately correct, the Tolk Analysis is primarily a retirement analysis – not a resource acquisition analysis. Therefore, allowing the model to evaluate a potentially infeasible amount of new generation on a possibly unrealistic timeline, allowed SPS to stress-test the economic benefit of continued operation of the Tolk Units. SPS will continue to monitor the feasibility and economic viability of adding economic energy resources.

Section 6F: Primary Conclusion – Economic Analysis

SPS's Tolk Analysis incorporated six different operational scenarios for Tolk, each with different retirement dates. Each scenario was evaluated using different sensitivities for (1) natural gas price forecast, (2) load growth uncertainty, and (3) inclusive of different levels of network upgrades assigned to replacement resources requiring a new GIA. This section of the Tolk Analysis focuses on two different sensitivity analyses: (1) the planning load forecast, with base natural gas forecast and $400/kW network upgrades and (2) the financial load forecast, with base natural gas forecast and $400/kW network upgrades. The PVRR tables for each sensitivity analysis are provided in Appendix F. Each PVRR table shows the impact to SPS's customers over three different periods (1) the action period (2022 – 2025), (2) the decision period (2022 – 2032), and (3) the planning period (2022 – 2041).

As shown below in Table 2, using the planning load forecast, with base gas price forecast and $400/kW of network upgrades, on a PVRR basis maintaining Tolk through 2032 (scenario 2) is $118M lower cost than a 2023 retirement (scenario 3) and $117M lower cost than a 2025 retirement (scenario 1), over the 20-year planning period. The savings are higher when evaluated on a shorter planning horizon. Over the 4-year action period, on a PVRR basis maintaining Tolk through 2032 is $235M lower cost than a 2023 retirement and $236M lower cost than a 2025 retirement. Over the 11-year decision period, on a PVRR basis maintaining Tolk through 2032 is $271M lower cost than a 2023 retirement and $266M lower cost than a 2025 retirement. Clearly, the early retirement of the Tolk Units results in a significant increase in cost to SPS's customers during each of the periods evaluated.

A staggered retirement of the Tolk Units fairs better than the early retirement of both units, but again is economically sub-optimal when compared to a 2032 retirement date. On a PVRR basis a staggered retirement (scenario 4) is $61M, $135M, and $93M higher cost than a 2032 retirement over the action, decision, and planning periods, respectively. A staggered retirement with seasonal operations is $30M, $87M, and $33M (scenario 5) higher cost than a 2032 retirement over the action, decision, and planning periods, respectively.

The earliest retirement of all SPS's coal burning units (scenario 6) is by far the least economical solution.

Table 2. Planning Load Forecast (Base Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022-2032	Delta ($M)	NPV ($M) 2022-2041
Scenario 2	$0	$3,213	$0	$7,426	$0	$11,949
Scenario 1	$236	$3,449	$266	$7,691	$117	$12,066
Scenario 3	$235	$3,448	$271	$7,696	$118	$12,067
Scenario 4	$61	$3,274	$135	$7,561	$93	$12,042
Scenario 5	$30	$3,243	$87	$7,513	$33	$11,982
Scenario 6	$789	$4,002	$1,398	$8,824	$1,526	$13,475

As shown below in Table 3 the results under the financial load forecast are in-keeping with the results of the planning load forecast. Each retirement scenario is higher cost than maintaining operation of the Tolk Units through 2032.

Table 3. Financial Load Forecast (Base Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022-2032	Delta ($M)	NPV ($M) 2022-2041
Scenario 2	$0	$2,993	$0	$6,628	$0	$10,388
Scenario 1	$146	$3,140	$165	$6,792	$128	$10,516
Scenario 3	$147	$3,140	$169	$6,797	$48	$10,436
Scenario 4	$38	$3,031	$88	$6,716	$75	$10,462
Scenario 5	$3	$2,996	$28	$6,655	$2	$10,390
Scenario 6	$548	$3,541	$796	$7,424	$755	$11,142

Section 6G: Value of Tolk Water Rights

The PVRR tables presented in Section 6F and included in Appendix F do not include the potential value of selling the Tolk Water Rights. If sold today, and using the methodologies described in Section 5D.3, SPS estimates the value of the water rights at somewhere between $0 and $20 million. The value of the water rights will continue to diminish with the declining availability of water.

Section 7: Conclusion

The 2021 Tolk Analysis continues to support seasonal operation of the Tolk Units through 2032 as the most reliable and economical solution. Maintaining the Tolk Units through 2032 is also a low risk solution – the early retirement of the Tolk Units would force SPS to seek new generating resources to meet its planning reserve margin requirements. Based on the high level of cost and schedule uncertainty in acquiring a new GIA, it is unclear if SPS could acquire adequate replacement resources in the timeframe necessary, and if so, exactly what costs these projects would be assigned. The cost of replacement generation could exceed the values included in the Tolk Analysis.

In addition, the Tolk Units continue to add significant reliability and fuel diversity benefits. These benefits were recently highlighted during the recent Winter Storm Uri. At the height of Winter Storm Uri, approximately 40% of SPS's natural gas supply was lost due to well freeze offs and natural gas processing plant failures associated with extreme cold weather and power outages throughout the Electric Reliability Council of Texas ("ERCOT") footprint. SPS was able to keep the Tolk and Harrington coal units operational which resulted in a reduction in dependence on natural gas supplies. Also, because SPS's coal generation was on-line during the winter storm, SPS's customers realized cost savings in the amount of approximately $600 million.

As an economical, low-risk, and reliable solution, the Tolk Analysis concludes the retirement date of the Tolk Units should remain at December 31, 2032.

Xcel Energy®

2020 Tolk Analysis
First Technical Conference

06/18/2020

The Tolk Analysis

- The uncontested comprehensive stipulation in New Mexico Case No. 19-00170-UT requires:
    - SPS to submit a robust analysis of Tolk abandonment and potential means of replacement by June 2021 (“The Tolk Analysis”)
    - The Tolk Analysis will be incorporated into SPS’s 2021 Integrated Resource Plan (“IRP”) application
    - The Tolk Analysis shall include:
        - **Two technical conferences**
        - **A review by an independent evaluator (“IE”)**
        - **Replacement resources priced based on an RFP or RFI process**
        - The value of reselling the water rights

Stipulation Requirements

The Tolk Analysis shall include evaluation of:

(i) the type, technical characteristics, and cost of the resources needed or available to replace the capacity provided by Tolk

(ii) The economically optimal (in terms of the public interest) abandonment dates for Tolk

(iii) The impact on customer rates of multiple abandonment scenarios based on the present value revenue requirements considering SPS's integrated resources

SPS also committed to running at least one scenario in which all of SPS's coal-burning units are retired or replaced by 2030

Technical Conferences

- **First Technical Conference – Present and solicit feedback on the basic parameters and approach of the Tolk analysis**
- Second Technical Conference – Provide and solicit feedback on the preliminary conclusions of the Tolk analysis
- Both technical conferences were to be held in-person in either Santa Fe or Albuquerque
- COVID-19 restrictions continue to present challenges for in-person meetings
- **SPS proposed to split the first technical conference into two separate sessions - The first being held today as a webinar**
- The second session of the first technical conference will be held either in-person or as a webinar in the near future

Agenda – Session 1 of 1st Technical Conference

To conduct a robust analysis in the timeframe required, SPS is presenting the following critical items for immediate consideration and review:

1. General approach of the Tolk Analysis
2. Request for Proposal (“RFP”) to acquire the services of an IE
3. Draft Request for Information (“RFI”) to obtain pricing of replacement resources
4. Outline of the scenarios SPS is proposing to evaluate

Agenda – Session 2 of 1st Technical Conference

The second session of the first technical conference will include the following discussions:

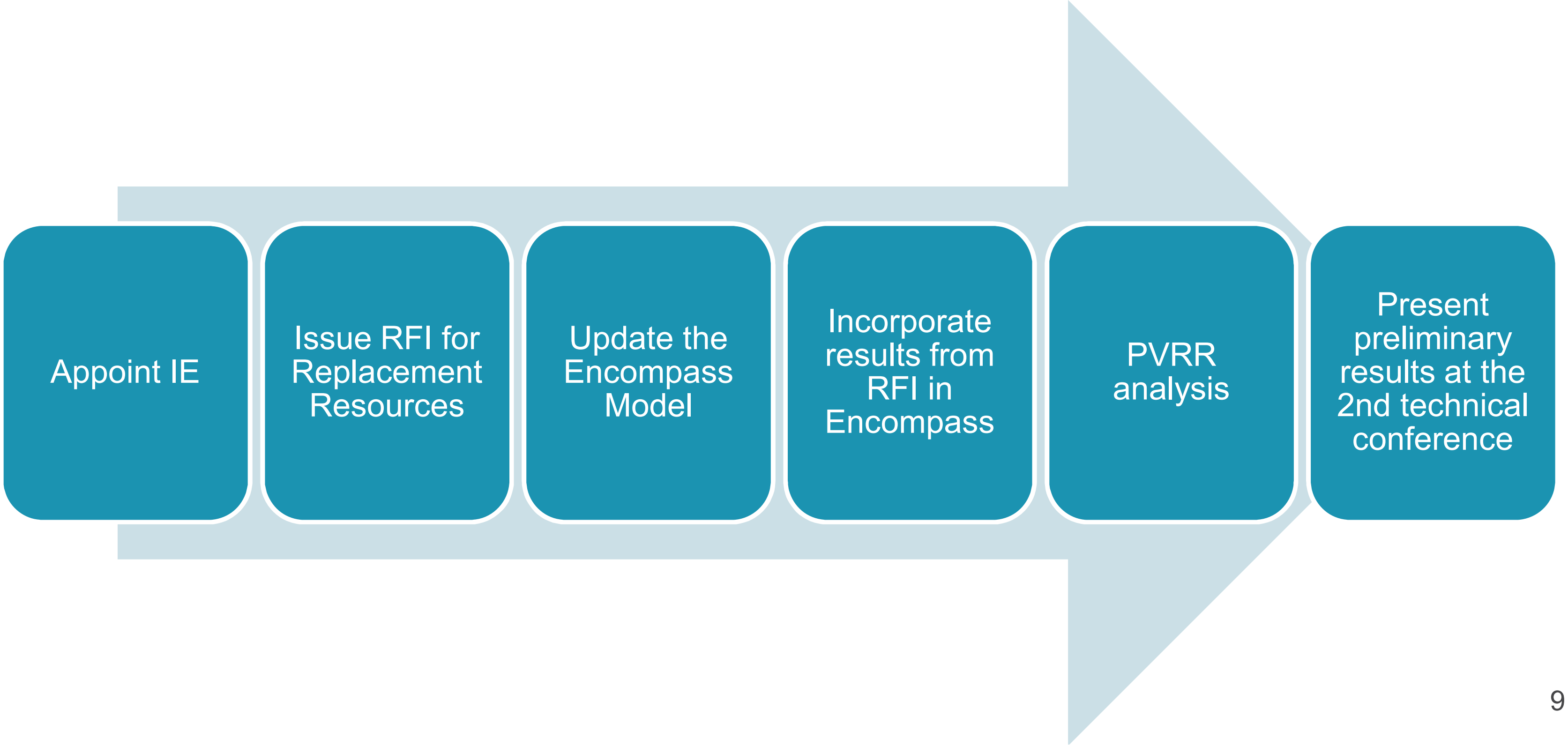
1. Finalize the RFI for pricing of replacement resources
2. SPS's Encompass model
3. Further discussion on the scenarios outlined in today's presentation
4. Critical modeling inputs and assumptions *(for example, SPS's gas forecast)*

Agenda Item 1:
General Approach to the Tolk Analysis

General Approach

- A Present Value Revenue Requirement ("PVRR") Analysis using the Encompass production cost modeling software
- Encompass will be discussed in detail during the second session of the first technical conference
- Evaluate multiple retirement and operating scenarios for SPS's coal units
- Each scenario will include an optimized expansion and generator replacement plan
- Type, technical characteristics, and cost of replacement generators available will be the result of an RFI process
- An IE will oversee the RFI process and Tolk Analysis

Process



Appoint IE

Issue RFI for Replacement Resources

Update the Encompass Model

Incorporate results from RFI in Encompass

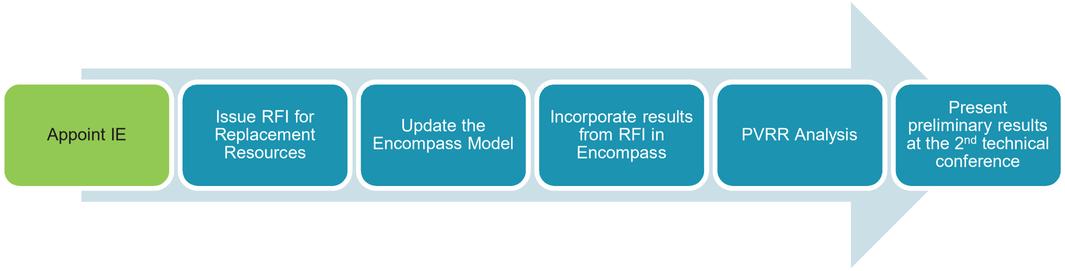
PVRR analysis

Present preliminary results at the 2nd technical conference

Agenda Item 2:
The Independent Evaluator

Independent Evaluator

- The New Mexico stipulation requires the Tolk Analysis to include a review by an IE
- SPS intends to issue an RFP to acquire the services of an IE
  - SPS is soliciting comments from interested parties to be submitted via email
  - Comments to be received within 7 days of this meeting
  - SPSTolkAnalysis@xcelenergy.com
- SPS's preference is for the IE to review the RFI for replacement resources before it is issued
- IE proposals will be due within 21 days of issuance of the RFP



Scope of Work
Independent Evaluator

Executive Summary

Southwestern Public Service Company ("SPS") is planning to issue an all-source Request for Information ("RFI") to obtain current pricing, technical characteristics, and other relevant information for potential generating resources. The results from the RFI will be incorporated into an evaluation of the potential abandonment and replacement of SPS's Tolk Station, herein known as "the Tolk Analysis," which will include an analysis in which all coal-burning units are retired or replaced before 2030 as set forth in the recent New Mexico Public Regulation Commission final order adopting the stipulation in SPS's most recent rate case.[1] SPS is seeking the services of an Independent Evaluator ("IE") to provide an independent review of the RFI process and Tolk Analysis to evaluate the fairness of SPS's bid solicitation and bid evaluation processes. Upon completion of the RFI solicitation and SPS's development of the Tolk Analysis, the IE will report its findings to the New Mexico Public Regulation Commission ("NMPRC") and SPS.

The primary objectives of the IE's independent review will be to:

- Assess whether that the RFI parameters are consistent with the objectives of the Tolk Analysis
- Assess whether the RFI documents including Standard Bidders Forms provide sufficient and consistent information for respondents to the RFI ("Bidders") to prepare proposals
- Identify any undue bias in the criteria used or as applied to evaluate bids
- Assess whether a consistent and fair methodology was used to screen and rank bids
- Assess whether the bids were fairly incorporated into the Tolk Analysis
- Provide an assessment of the Tolk Analysis including any deficiencies in the parameters or results of the analysis

Background

Tolk Station consists of two coal-powered steam turbine units, located in Lamb County, Texas. Each unit has a net capacity of approximately 540 MW, for a total net capacity of approximately 1,080 MW.

Tolk Station relies exclusively on groundwater from the Ogallala Aquifer for generation cooling, and the Ogallala Aquifer is in an irreversible decline. To conserve water, and the life of Tolk Station, SPS has implemented a plan to reduce the number of hours the Tolk units operate annually.

---

[1] Uncontested Comprehensive Stipulation ("Stipulation") filed at the New Mexico Public Regulation Commission on January 13, 2020 and approved by the New Mexico Public Regulation Commission ("NMPRC") in Case No. 19-00170-UT.

SPS is required to analyze a range of operating parameters and retirement dates for Tolk Station. The analysis will incorporate the pricing and technical characteristics obtained in the RFI process. The results of the analysis will be included in SPS's next Integrated Resource Plan ("IRP"), to be filed in July 2021.

As part of the Tolk Analysis, SPS will use the information obtained from this RFI to include an evaluation of the potential retirement and replacement of all of SPS's coal burning generation.

Timeline

SPS is required to complete the Tolk Analysis by June 2021, one month before the IRP. To meet the filing date, SPS anticipates issuing the RFI in the Summer of 2020. Bidders will then be given 60 days to submit their proposals. The evaluation process and Tolk Analysis is expected to take approximately six months from receipt of bids.

IE Responsibilities

To achieve the primary objectives, the IE will be provided immediate and continuing access to all documents and data reviewed, used, or produced by SPS in the preparation of the Tolk Analysis and in its bid solicitation, evaluation, and selection processes. SPS will provide to the IE bid evaluation results and modeling runs so that the IE can verify these results and can investigate options that SPS did not consider.

To conduct a thorough, independent, and unbiased review of the RFI process and Tolk Analysis, the IE will perform the following activities:

Meetings

The IE will attend an initial kickoff meeting prior to issuance of the RFI either via teleconference or in person at SPS's offices in Amarillo, Texas. The kickoff meeting will provide an opportunity to discuss the RFI parameters, specific items which may be required for the Tolk Analysis, and SPS's thoughts, goals and objectives regarding the RFI and Tolk Analysis. SPS will establish and explain confidentiality protection procedures regarding bid information and evaluation. Additional details regarding project administration and public communications will be discussed at the kickoff meeting as well.

The IE will conduct regular project status calls with SPS to discuss the project and identify and mitigate any issues that arise.

The IE will attend via teleconference at all future public technical conferences and other meetings as necessary to achieve the primary objectives.

Review and Finalize RFI Documents and Evaluation Process

The IE will critically review the draft RFI and any associated documents and notification communications with the objective of determining whether there are any undue biases presented to any category of potential Bidders as a result of the structure of the RFI requirements and make recommendations as needed. Additionally, the IE will review and evaluate the draft proposal submittal requirements and standard bidder forms and make recommendations as needed.

Review Bidder Communications

Upon issuance of the RFI, the SPS staff directly involved with the RFI will adhere to strict communication protocols with Bidders. The IE will examine any communications between SPS and Bidders during the RFI review period, which will begin with the issuance of the RFI and end with filing of SPS's 2021 integrated resource plan in July 2021. The purpose of this examination will be to determine whether Bidders were treated fairly during the submittal and evaluation periods, and whether SPS was unduly biased toward a specific bid.

Evaluate the SPS Economic Modeling of Bids

The IE shall conduct a thorough and unbiased review of the due diligence activities performed by SPS for each prospective bid, as well as a review of the economic modeling of each bid to confirm the modeling was accurate and consistent across all bids.

In reviewing the due diligence activities, the IE will review each bid and associated Standard Bidding Forms, followed by a review of SPS's documented non-economic evaluation of all bids.

Evaluation of the Tolk Analysis

The IE shall conduct a thorough, and unbiased review of the Tolk Analysis parameters and results. The review should include, but not be limited to, consideration of potentially different retirement dates of the Tolk units, the feasibility of acquiring adequate replacement resources in the timeframe necessary, and availability of economic water in each of the scenarios modeled.

The IE will conduct a thorough review of key inputs and parameters to the Tolk Analysis including, but not limited, SPS's natural gas price forecasts and system load forecasts.

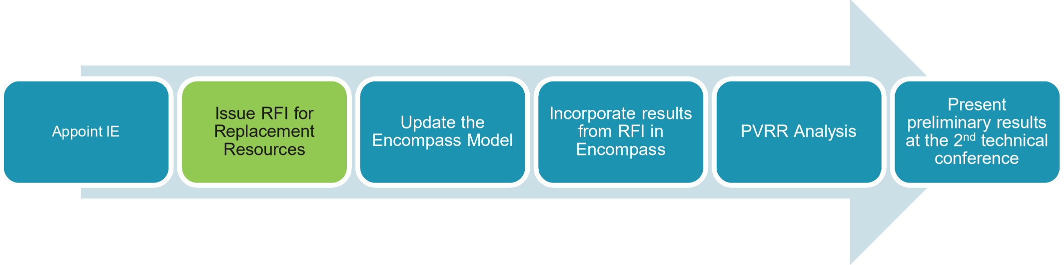
Prepare and Provide Independent Review Report

The IE will prepare a detailed report of its findings and conclusions regarding the Tolk Analysis. Initial drafts of the report are anticipated to be reviewed internally by SPS and in collaboration with the IE for quality assurance. After incorporating any necessary revisions to the report that are identified as a result of the reviews, the IE will issue the final report redacted as necessary to ensure protection of confidential information; confidential information referenced should be made available only under appropriate protective order procedures.

Agenda Item 3:
RFI – Pricing for Replacement Resources

RFI for Replacement Resources

- SPS will issue an all-source solicitation for replacement generating resources
- SPS will consider all ownership structures including, but not limited to, purchased power agreements, build-own-transfers, and company self-built facilities
- Bidders will be required to provide information necessary to accurately model the proposed resources – including, but not limited to: pricing, technical characteristics, generator output, commercial operation date
- SPS is soliciting comments from interested parties to be submitted via email
  - Comments to be received within 28 days of this meeting
  - Comments will be discussed at the 2nd Session of the 1st Technical Conference
  - SPSTolkAnalysis@xcelenergy.com



Appoint IE

Issue RFI for Replacement Resources

Update the Encompass Model

Incorporate results from RFI in Encompass

PVRR Analysis

Present preliminary results at the 2nd technical conference

DRAFT

Southwestern Public Service Company Request for Information

Introduction:

This announcement constitutes a Request for Information ("RFI") notice soliciting current pricing, technical characteristics, and other relevant information for potential generating resources. This is not a Request for Proposals ("RFP") or solicitation for formal proposals. This RFI does not constitute a commitment, implied or otherwise, that SPS will take action in this matter. SPS will not be responsible for any costs incurred in furnishing SPS responsive information.

SPS is interested in understanding the current availabilities, flexibilities, and preferences of market participants interested in providing capacity and associated energy to SPS from all generating resource types, including energy storage, whether existing or yet-to-be constructed. SPS is considering the availability of capacity resources for possible future owned generation, build-own-transfers ("BOTs"), and purchased power agreements ("PPAs").

General Background:

- SPS is a New Mexico corporation and wholly-owned electric utility subsidiary of Xcel Energy.
- SPS's total company service territory encompasses a 52,000-square-mile area in eastern and southeastern New Mexico, the Texas Panhandle, and the Texas South Plains and its primary business is generating, transmitting, distributing, and selling electric energy.
- SPS has a long history of providing safe, reliable, value-added service to our customers
- SPS serves 394,220 electric retail customers in Texas and New Mexico.
- As prescribed in the Uncontested Comprehensive Stipulation ("Stipulation") filed at the New Mexico Public Regulation Commission on January 13, 2020 and approved by the New Mexico Public Regulation Commission ("NMPRC") in Case No. 19-00170-UT, the Stipulation requires SPS to submit a robust analysis of the possible abandonment of its Tolk Generating Station Units 1 and 2 (Tolk) and potential means of replacement of those resources (the "Tolk Analysis"). The Tolk Analysis shall include replacement resources priced based on an RFI solicitation. The Tolk Analysis will also consider a scenario in which all SPS's coal-burning units are retired or replaced before 2030.
- SPS will be evaluating multiple scenarios with various capacity replacement dates. The minimum net capacity need is approximately 500 MW beginning summer 2023. The maximum net capacity need is approximately 2,200 MW beginning summer 2025.

Qualifications and Assumptions:

- Expressions of interest should be from existing or proposed generating facilities within the SPS zone or delivered to the SPS zone from existing or proposed sites within the Southwest Power Pool.
- Expressions of interest should include a proposed Commercial Operation Date ("COD") if the submission is a future resource.
- Expressions of interest should include all capacity, energy, environmental attributes such as Renewable Energy Credits (RECs), and other generation-related services.
- For purposes of this RFI, "renewable energy" refers to electrical power generated by solar, wind, biomass, or other commercially viable renewable energy technologies including energy storage.
- SPS is interested in the availability of capacity and associated energy resources for possible future owned generation, BOTs, and PPAs.
- PPA durations should be 25 and 30 years.
- Interested parties should respond to this RFI within 60 days of issuance.

Specific Information of Interest:

- Project type, including technical characteristics.
- Project site location for delivery within (or to) the SPS system.
- Proposed COD for resource facilities responsive to this RFI, including details on whether a delay in the proposed COD could impact the pricing and if so an estimate of the price of those impact(s).
- Pricing and quantity in megawatts. All pricing in respondent proposals should reflect costs (to the extent applicable) at the time of submittal and should include costs of interconnection to the transmission system if applicable.
- Statement on current interconnection status (if any), and anticipated extent of need for transmission system upgrades for the proposal.
- Proposals must demonstrate an anticipated ability to obtain all required state/local pre-construction approvals and any associated risks to meet the COD.

Content of Submissions:

- Appendix A includes a set of forms applicable to the resource type being submitted.
    - For dispatchable resources the submitter should complete Appendix A-D forms
    - For renewable generation resources the submitter should complete Appendix A-R forms
    - For Build-Own-Transfer or sale of an existing asset the submitter should complete Appendix A-CO.

- Some information may be requested on more than one form. Although such requests may be redundant, submitters must provide the information requested on each applicable form. Submitters must submit an electronic copy provided on a USB drive in a Microsoft Office format to SPS at the address given below.

DRAFT

Proposal Submission Deadline:

Proposals will be accepted until 5:00 P.M. Central Time on **Friday, August __, 2020**. All Proposals must be transmitted by express, certified or registered mail, or hand delivered to SPS's RFI point of contact at the following address:

SPS 2020 All-Source RFI submission:

SPS 2020 All-Source RFI
Attn: Resource Planning
Xcel Energy Services Inc.
1800 Larimer Street, Suite 700
Denver, CO 80202

Proposals received later than the due date and time indicated will be rejected and returned unopened, unless SPS determines in its sole discretion that extenuating circumstances led to late delivery.

Follow-up Requests

To the extent SPS has questions or seeks clarification regarding a Proposal, SPS may pose follow-up questions. Submitters are not obligated to respond to such follow-up questions, but are advised that a failure to provide adequate information may lead to a Proposal or a portion of a Proposal being disregarded.

Confidentiality

SPS recognizes that certain information contained in a Proposal submitted may be deemed by the submitter to be confidential. To the extent a submitter believes portions of its Proposal (or any subsequent responses to follow-up questions) constitute confidential material, the submitter should clearly label such material as confidential ("Confidential Material"). SPS will not be responsible for identifying any Confidential Material that has not been designated as such by the submitter. If SPS receives a request from a regulatory or judicial authority to which Confidential Material is responsive, or if SPS receives a request (that SPS reasonably deems to be a valid request) from a party in a regulatory or judicial proceeding to which request SPS determines Confidential Material in the Proposal is responsive, or to the extent otherwise required by law, SPS may provide the Confidential Material pursuant to a confidentiality or protective agreement or order in such proceeding. To the extent Confidential Material is proposed to be disclosed publicly (i.e., not subject to a confidentiality or protective agreement), SPS will notify the submitter as soon as reasonably possible; it is the sole responsibility of the submitter to seek to protect the material subsequent to such notification. SPS may disclose non-Confidential Material at its discretion without prior notice.

Agenda Item 4:
Overview of Scenarios being Evaluated

Multiple Tolk Retirement Scenarios

- Reduced operations
  - SPS’s currently implemented plan
  - Both units are economically dispatched June – September and offline in off-peak months

- Economic Dispatch
  - Both units are economically dispatched in all months

- Earliest Retirement of Both Tolk Units
  - Both units are economically dispatched in all months
  - Both units are retired as soon as feasible*

** Feasibility will be determined based on COD dates of replacement resources as submitted in the RFI*

Multiple Tolk Retirement Scenarios Continued

- Staggered Retirement of Tolk Units
  - One unit is retired as soon as feasible*
  - Second unit will be retired upon depletion of economically available water

- Earliest Retirement of all Coal-Burning Units

** Feasibility will be determined based on COD dates of replacement resources as submitted in the RFI*

Xcel Energy®

2020 Tolk Analysis: Session 2 of the 1st Technical Conference

09/01/2020

Today’s Meeting Agenda

1. Prior and Future Technical Conferences
2. Updates from Prior Technical Conference
    A. Independent Evaluator
    B. Request for Information for generating resources
3. Encompass – Production Cost Modeling Software
4. Responses to Parties Comments and Questions
    A. SPS Load Forecast Update
    B. Sierra Club Modeling Questions

Agenda for Future Technical Conferences

Future Technical Conferences will include the following topics:

1. Harrington Station
2. Tolk Analysis – Retirement dates and operating scenarios
3. Value of Tolk water rights
4. Modeling Parameters

Xcel Energy®

Agenda Item 1: Prior and Future technical conferences

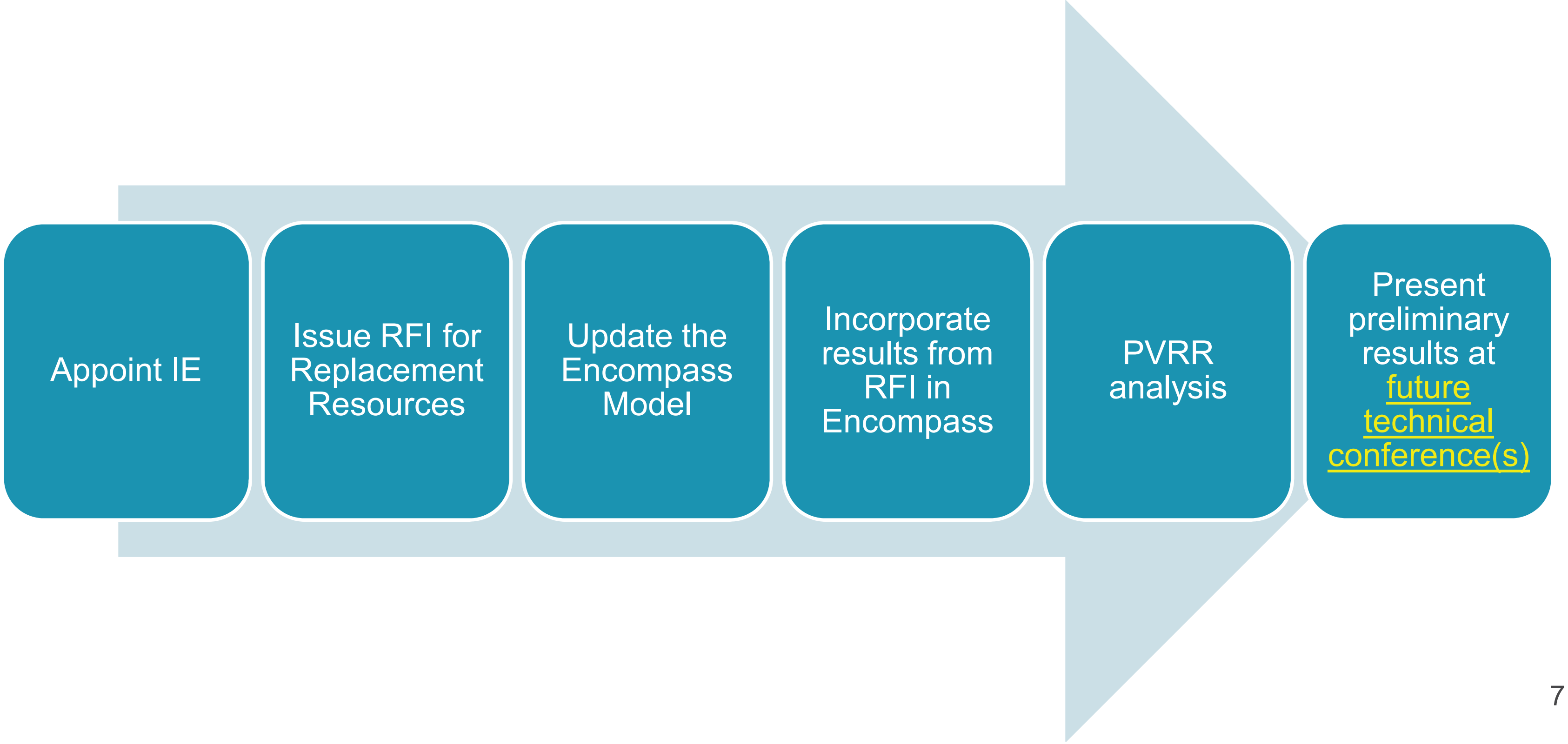
Prior & Future Technical Conferences

- SPS held the first technical conference on June 18th 2020
- Agenda Items included:
    - SPS’s general approach to the Tolk Analysis
    - Request for Proposal (“RFP”) to acquire the services of an IE
    - Draft Request for Information (“RFI”) to obtain pricing of replacement resources
    - Outline of the scenarios SPS is proposing to evaluate
- Originally planned to address all other outstanding requirements in this technical conference
- SPS is now proposing to schedule regular technical conferences to adequately address parties concerns, questions and comments

General Approach

- A Present Value Revenue Requirement ("PVRR") Analysis using the Encompass production cost modeling software
- Encompass will be discussed in detail later in this presentation
- Evaluate multiple retirement and operating scenarios
- Each scenario will include an optimized expansion and generator replacement plan
- Type, technical characteristics, and cost of replacement generators available will be the result of an RFI process
- An IE will oversee the RFI process and Tolk Analysis

Process



- Appoint IE
- Issue RFI for Replacement Resources
- Update the Encompass Model
- Incorporate results from RFI in Encompass
- PVRR analysis
- Present preliminary results at future technical conference(s)

Agenda Item 2A: Independent Evaluator

Independent Evaluator

Actions taken during, or since, the previous technical conference:

- Solicitated feedback for draft RFP and associated questionnaire
- Issued the RFP to obtain the services of an Independent Evaluator
- Recommended selection of Guidehouse (f/k/a Navigant Consulting, Inc.)
- Appointed Guidehouse as the Independent Evaluator

Next Steps

- None – Task Complete

Introduction to Guidehouse

- Expert-based, international consulting firm with diverse technical capabilities and a deep understanding of resource planning & procurement, interconnection studies, infrastructure planning and grid operations
- Over a decade of experience conducting Independent Evaluation for resource procurement engagements
- Over 25 years of experience with supply resource solicitations & bid evaluations
- Comprehensive knowledge spans from RFP development, issuance & administration, to bid evaluation, PPA development & negotiation, regulatory support, and expert testimony
- Expertise in power resource procurement that spans more than three decades with a thorough understanding of industry practices across multiple jurisdictions
- Core Team’s industry experience from 14 to over 35 years

Agenda Item 2B: Request for Information

Recap: RFI for Replacement Resources

- SPS will issue an all-source solicitation for replacement generating resources to provide capacity and associate energy
- SPS will consider all ownership structures including, but not limited to, purchased power agreements, build-own-transfers, and company self-built facilities
- Bidders will be required to provide information necessary to accurately model the proposed resources – including, but not limited to: pricing, project type & location, technical characteristics, generator output, commercial operation date

Request for Information

Actions taken during, or since, the previous technical conference:

- Solicitated feedback during first technical conference for draft RFI
- Provided draft RFI to Guidehouse for IE review

Next Steps

- Issue RFI within 5 business days
- Receive proposals within 60 days of issuance

Southwestern Public Service Company Request for Information

Introduction:

This announcement constitutes a Request for Information ("RFI") notice soliciting current pricing, technical characteristics, and other relevant information for potential generating resources. This is not a Request for Proposals ("RFP") or solicitation for formal proposals. This RFI does not constitute a commitment, implied or otherwise, that SPS will take action in this matter. SPS will not be responsible for any costs incurred in furnishing SPS responsive information.

SPS is interested in understanding the current availabilities, flexibilities, and preferences of market participants interested in providing capacity and associated energy to SPS from all generating resource types, including energy storage, whether existing or yet-to-be constructed. SPS is considering the availability of capacity resources for possible future owned generation, build-own-transfers ("BOTs"), and purchased power agreements ("PPAs").

General Background:

- SPS is a New Mexico corporation and wholly-owned electric utility subsidiary of Xcel Energy.
- SPS's total company service territory encompasses a 52,000-square-mile area in eastern and southeastern New Mexico, the Texas Panhandle, and the Texas South Plains and its primary business is generating, transmitting, distributing, and selling electric energy.
- SPS has a long history of providing safe, reliable, value-added service to our customers
- SPS serves 394,220 electric retail customers in Texas and New Mexico.
- As prescribed in the Uncontested Comprehensive Stipulation ("Stipulation") filed at the New Mexico Public Regulation Commission on January 13, 2020 and approved by the New Mexico Public Regulation Commission ("NMPRC") in Case No. 19-00170-UT, the Stipulation requires SPS to submit a robust analysis of the possible abandonment of its Tolk Generating Station Units 1 and 2 (Tolk) and potential means of replacement of those resources (the "Tolk Analysis"). The Tolk Analysis shall include replacement resources priced based on an RFI solicitation. The Tolk Analysis will also consider a scenario in which all SPS's coal-burning units are retired or replaced before 2030.
- SPS will be evaluating multiple scenarios with various capacity replacement dates. The minimum net capacity need is approximately 500 MW beginning summer 2023. The maximum net capacity need is approximately 2,200 MW beginning summer 2025.

Qualifications and Assumptions:

- Expressions of interest should be from existing or proposed generating facilities within the SPS zone or delivered to the SPS zone from existing or proposed sites within the Southwest Power Pool.
- Expressions of interest should include a proposed Commercial Operation Date ("COD") if the submission is a future resource.
- Expressions of interest should include all capacity, energy, environmental attributes such as Renewable Energy Credits (RECs), and other generation-related services.
- For purposes of this RFI, "renewable energy" refers to electrical power generated by solar, wind, biomass, or other commercially viable renewable energy technologies including energy storage.
- SPS is interested in the availability of capacity and associated energy resources for possible future owned generation, BOTs, and PPAs.
- PPA durations are recommended to be 25 and/or 30 years.
- Interested parties should respond to this RFI within 60 days of issuance.

Specific Information of Interest:

- Project type, including technical characteristics.
- Project site location for delivery within (or to) the SPS system.
- Proposed COD for resource facilities responsive to this RFI, including details on whether a delay in the proposed COD could impact the pricing and if so an estimate of the price of those impact(s).
- Pricing and quantity in megawatts. All pricing in respondent proposals should reflect costs (to the extent applicable) at the time of submittal and should include costs of interconnection to the transmission system if applicable.
- Statement on current interconnection status (if any), and anticipated extent of need for transmission system upgrades for the proposal.
- Proposals must demonstrate an anticipated ability to obtain all required state/local pre-construction approvals and any associated risks to meet the COD.

Content of Submissions:

- Appendix A includes a set of forms applicable to the resource type being submitted.
    - For dispatchable resources the submitter should complete Appendix A-PPA_DIS forms
    - For renewable generation resources the submitter should complete Appendix A-PPA_RENEW forms
    - For Build-Own-Transfer or sale of an existing asset the submitter should complete Appendix A-BOT.
- Some information may be requested on more than one form. Although such requests may be redundant, submitters must provide the information requested on each applicable form.
- SPS will convene a Bidders Meeting for all interested parties to allow for clarifications and any questions that potential bidders may have. See meeting details below.

Bidders Meeting:

Date: September 21, 2020

Time: 1:00PM – 3:00 PM Mountain Daylight Time

Join Zoom Meeting:
https://xcelenergy.zoom.us/j/93175193060?pwd=cVpNeTZvTEkycURlMUhqMlZWL2l4dz09

Meeting ID: 931 7519 3060
Passcode: 270511
One tap mobile
+17209289299,,93175193060#,,,,,,0#,,270511# US (Denver)
+12133388477,,93175193060#,,,,,,0#,,270511# US (Los Angeles)

Dial by your location
+1 720 928 9299 US (Denver)
+1 213 338 8477 US (Los Angeles)
+1 346 248 7799 US (Houston)
+1 206 337 9723 US (Seattle)
+1 312 626 6799 US (Chicago)
+1 646 518 9805 US (New York)
+1 651 372 8299 US (St. Paul)
+1 786 635 1003 US (Miami)
Meeting ID: 931 7519 3060
Passcode: 270511
Find your local number: https://xcelenergy.zoom.us/u/aLUXvN6pb

Proposal Submission Deadline:

Proposals will be accepted until 5:00 P.M. Central Time on **Friday, November 6, 2020**. All Proposals must be transmitted by to the following email address:

SPSTolkAnalysis@xcelenergy.com

Proposals received later than the due date and time indicated will be rejected.

Follow-up Requests

To the extent SPS has questions or seeks clarification regarding a Proposal, SPS may pose follow-up questions. Submitters are not obligated to respond to such follow-up questions, but are advised that a failure to provide adequate information may lead to a Proposal or a portion of a Proposal being disregarded.

Confidentiality

SPS recognizes that certain information contained in a Proposal submitted may be deemed by the submitter to be confidential. To the extent a submitter believes portions of its Proposal (or any subsequent responses to follow-up questions) constitute confidential material, the submitter should clearly label such material as confidential (“Confidential Material”). SPS will not be responsible for identifying any Confidential Material that has not been designated as such by the submitter. If SPS receives a request from a regulatory or judicial authority to which Confidential Material is responsive, or if SPS receives a request (that SPS reasonably deems to be a valid request) from a party in a regulatory or judicial proceeding to which request SPS determines Confidential Material in the Proposal is responsive, or to the extent otherwise required by law, SPS may provide the Confidential Material pursuant to a confidentiality or protective agreement or order in such proceeding. To the extent Confidential Material is proposed to be disclosed publicly (i.e., not subject to a confidentiality or protective agreement), SPS will notify the submitter as soon as reasonably possible; it is the sole responsibility of the submitter to seek to protect the material subsequent to such notification. SPS may disclose non-Confidential Material at its discretion without prior notice.

Xcel Energy®

Agenda Item 3: Encompass

Jon Landrum | Manager of Resource Planning Analytics

Impetus for Change

- Need for more detailed analyses around operational impact of plans; Increasing reliance on intermittent and storage resources
- Stakeholder requests for more detailed modeling in the complex and evolving resource environment
- Opportunity to improve visibility and transparency of modeling inputs/outputs
- Strategist is no longer a “supported” product by vendor, leading to potential future operational challenges

Replacement Options, Identification and Evaluation

- Developed and issued RFI on Aug 17, 2017 (Received responses from 12 vendors)
  - ABB (Capacity Expansion)
  - EPIS (Aurora)
  - Energy Exemplar (Plexos)
  - Vibrant Clean Energy (WIS:dom)
  - Abacus Solutions(Saturn)
  - PCI (GenTrader)
  - EPRI (EGEAS)
  - Anchor Power (EnCompass)
  - NREL (RPM)
  - Ascend Analytics (PowerSimm)
  - E3 (RESOLVE)
  - Newton Energy (ENELYTX)
- Evaluation team reviewed and scored vendor responses based on specific RFI criteria; selected 4 vendors to present in-person (presentations held Nov 13-14, 2017)
  - ABB (Capacity Expansion)
  - EPIS (Aurora)
  - Energy Exemplar (Plexos)
  - Anchor Power (EnCompass)

Replacement Options, Identification and Evaluation (cont)

- Selected two finalists based on detailed discussions with vendors and evaluation of materials presented; conducted in-house evaluation of finalist systems
    - EPIS (Aurora)
    - Anchor Power (EnCompass)
- Xcel demos/training conducted Nov 2018
    - Installed software in test environment
    - 2-5 webex training sessions led by vendor
    - 2 weeks (each) allocated to testing and gaining familiarity with models
- Selected EnCompass as preferred alternative

Model Features

	Encompass
Functionality	• Modern “solve anything” algorithm • Hourly operation detail (accurately captures ramp rates, start ups, etc.) • Enhanced storage logic and ancillary services • Able to perform utility capital accounting (revenue requirements) • National database, regional simulation capability
Ease of implementation	• Easily import existing data • Data structure easy to understand/manage • Similar source data requirements as existing processes
Transparency	• Regulatory license available at $20k/yr • All data inputs/outputs are easily shareable in Excel spreadsheets

Key Stakeholder Issues Addressed

Concern	Encompass Advantages over Strategist
Transparency / Access	• Fully functional low-cost license for regulators/stakeholders • All inputs/outputs are readable in non-proprietary Excel
Storage Modeling	• Enhanced storage modeling with hourly detail • Capable of sub hourly dispatch, wider array of ancillary services incorporated in model • Sophisticated state-of-charge limit logic
Modeling of Renewables, DER, Markets	• Hourly chronological dispatch • Able to use less granularity for strategic evaluations • Broader market integration capability
Existing Unit Eval (EUE)	• Able to solve highly complex models
Model Environmental Impacts	• Enhanced capability of modeling and simultaneously optimizing all emissions costs / programs / caps

QUESTIONS & DISCUSSION

Xcel Energy®

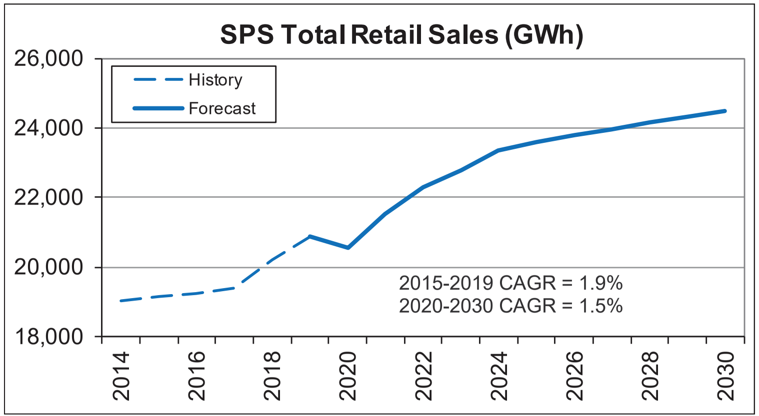
Agenda Item 4A: SPS Sales and Demand Forecast Update

Jannell Marks | Director of Energy Sales and Demand Forecast

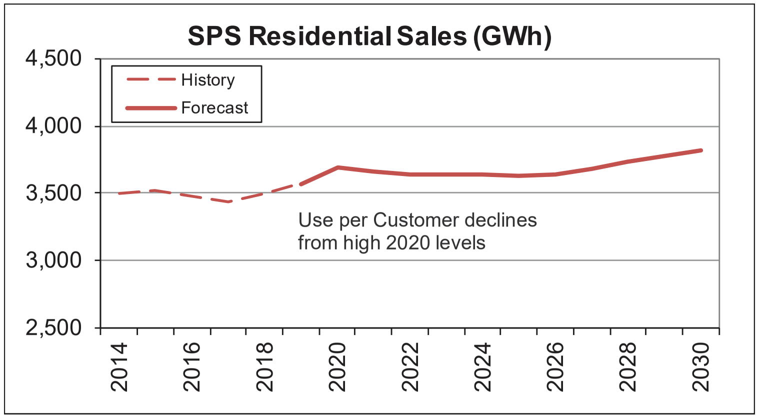
SPS Forecast Assumptions

- Current economic outlook shows significant COVID-19 impacts in 2020 with impacts moderating through 2024
  - Most significant impact in Q2 2020
- Residential use per customer is higher than recent past and Small C/I use per customer is lower
  - Both Residential and Small C/I use per customer return to long-term trends after 2020, but take several years to return to prior levels
  - Assume loss of Small C/I customers due to business closures in “experience economy” sectors (Arts and Entertainment, Restaurants and Bars, Retail)
- Large C/I shows signs of recovery by end of 2020
  - Slowdown in Oil and Gas extraction/drilling in Q2, Q3 2020
  - Additional negative impacts in 2020 and into 2021 for other mining/manufacturing customers
- Continued declines in Wholesale as contracts ramp down/expire

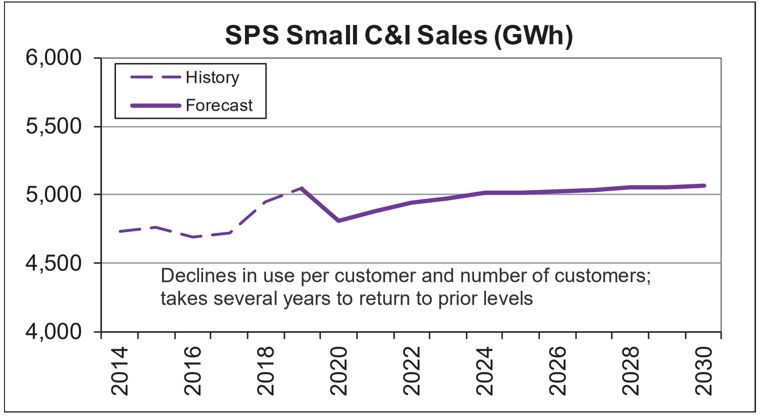
SPS Retail Sales



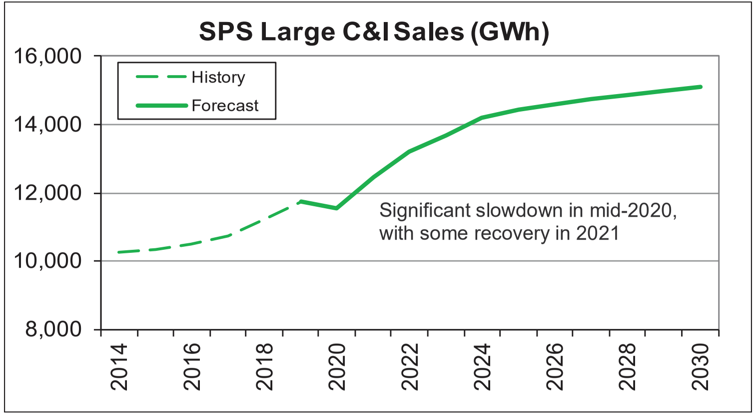
2015-2019 CAGR = 1.9%
2020-2030 CAGR = 1.5%



Use per Customer declines
from high 2020 levels

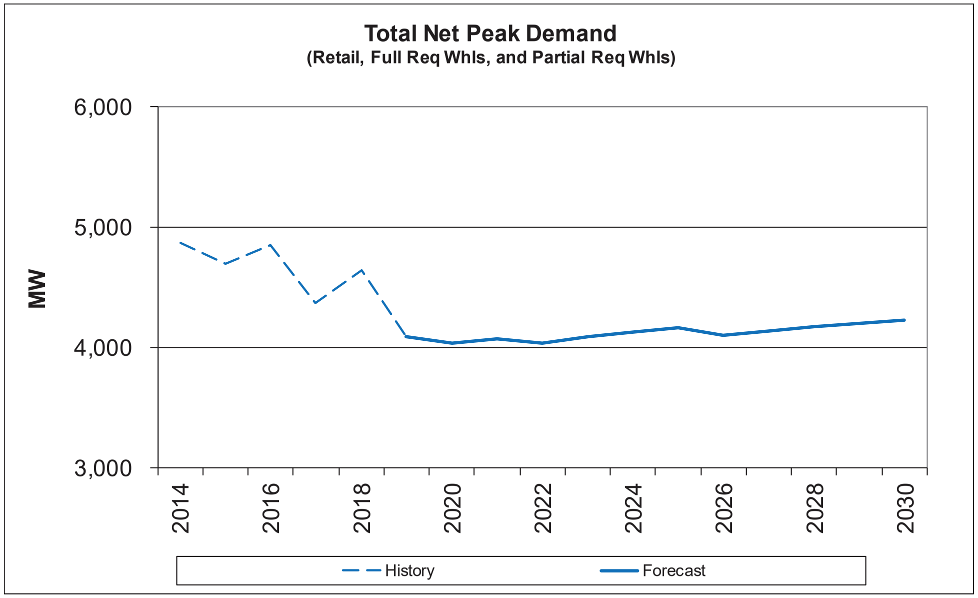


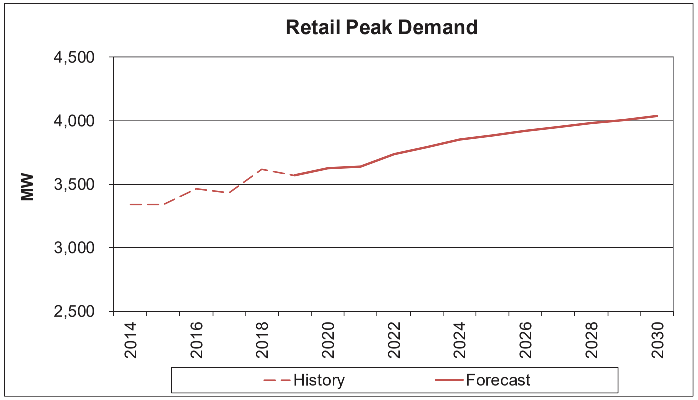
Declines in use per customer and number of customers;
takes several years to return to prior levels

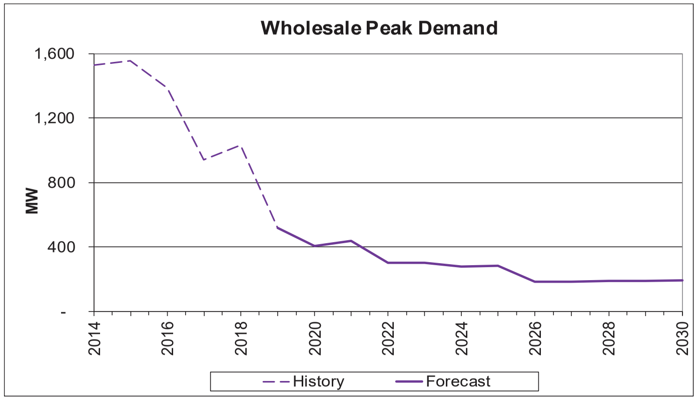


Significant slowdown in mid-2020,
with some recovery in 2021

SPS System Peak Demand







QUESTIONS & DISCUSSION

Xcel Energy®

Agenda Item 4B: Sierra Club Follow-up Discussion

General Modeling Questions

Q. ***Market power, both firm and non-firm: Is Xcel modeling just resources from the RFP process, or is the Company also planning to model market power as an option to replace some generation and capacity? What cost and availability assumption is Xcel using for these potential purchases?***

A. SPS include the availability to purchase (sell) energy from the SPP Integrated Market. SPS include the option to purchase up to 100MW of short-term capacity from SPP. SPS will utilize the most recent market price forecast.

Q. ***When evaluating the least cost solution for Harrington, is SPS evaluating whether it actually has a need for the full capacity and services currently provided by Harrington, or is SPS simply comparing the cost of the plant on natural gas and coal to the cost of providing identical services from alternative resources?***

A. SPS only evaluates system needs and not like-in-kind replacement of generators. For example, if the retirement of all three Harrington units created a capacity shortage of 250MW in 2025. SPS's analysis would only require 250MW of additional capacity in 2025, not the full capacity of Harrington. In this example, 250MW would be the minimum amount of capacity required, not the maximum.

General Modeling Questions

Q. ***Reliability: How is Xcel planning to model the firm capacity contribution of solar and wind? Does the Company plan to conduct reliability modeling to inform its ELCC assumptions? Is the Company planning to use resource blocks to reflect the changing contribution of each resource as the amount installed on the system increases? What about paired wind and solar resources?***

A. SPS will incorporate SPP's most recent ELCC calculations to assign accredited capacity to renewable resources. SPP's methodology includes resource blocks to reflect the changing contribution of each resource. SPP has not developed a methodology to determine paired wind and solar accreditation.

Q. ***Will the Company assume a reduction in spending in years directly prior to plant retirements? / What costs and assumptions for sustaining capital costs is SPS planning to use in its Harrington analysis? / Does Xcel has a schedule of sustaining capital costs that it plans to incorporate into EnCompass? What is the assumed step-down in spending in years prior to retirement?***

A. SPS will incorporate the most recent capital budget in the analysis, with scenario specific capital and O&M budgets developed for Tolk and Harrington. SPS will include a managed decline of expenditure in the years directly prior to plant retirements.

General Modeling Questions

Q. ***Optimized modeling vs scenario modeling: We would like to understand the main factors driving Xcel / EnCompass' selection of optimal retirement date. We believe that optimized retirement runs should be foundation of this analysis. However we would encourage Xcel to also think about hard coding sensitivities based on optimized results to understand how sensitive the model is to specific assumptions. For example, if an optimized run indicates that a 2027 retirement date for Tolk is least cost, but a hard coded retirement of 2025 is only a tiny bit more expensive, is the result of 2027 actually meaningful or is the difference between 2025 and 2027 just a reflection of, for example, the estimated sustaining capital cost assumptions? It is essential that the Company understands and is transparent about which modeling results are significant and which are likely not.***

A. SPS will evaluate whether alternative retirement dates could provide a preferable plan. However, parties must consider that all scenarios modeled will be subject to uncertainties in cost and operation assumptions. Cherry-picking uncertainties in one scenario, without exercising the same objectivity in other scenarios will not meet SPS's goal of a fair and unbiased analysis. In addition to evaluating the economic attributes of each scenario, SPS will also consider system reliability, operational constraints, and feasibility of acquiring new generation.

Harrington Station Questions

Q. Does SPS plan to use the IRP process to make the final decision on whether to retire, repower on natural gas, or install scrubbers at Harrington? Or does the Company plan to make a decision prior to or outside the IRP process?

A. "The IRP process will not itself be used to make the decision on Harrington, though there is overlap. I'd anticipate there will be discussion of Harrington within the IRP process, including regarding the additional questions you posed"[1].

Q. Harrington has to install scrubbers for SO2 NAAQS and/or regional haze compliance by 2024

A. SPS has already evaluated installing scrubbers and DSI for SO2 NAAQS compliance and determined it to be uneconomical.

Q. When evaluating Harrington, the Company should run at least one scenario requiring compliance with National Ambient Air Quality Standard for sulfur dioxide as expeditiously as practicable, 42 U.S.C. § 7502(c)(1), and no later than 2024

A. SPS has already evaluated an early conversion to gas (2022) and determined an early conversion provided no clear economical benefit.

---

[1] Per the email response from Will DuBois, Lead Assistance Counsel, to the distribution list for the 2021 SPS NM IRP First Tolk-Related Technical Conference in response to the email from Joshua Smith from Sierra Club

Harrington Station Questions

Q. ***Does SPS plan to model seasonal operation of Harrington when operating both on coal and natural gas in its analysis?***

A. No. When operating on coal, seasonal operations alone will not bring Harrington into compliance with NAAQS. When operating on gas, Harrington will provide capacity, energy and reliability benefits all year round.

Q. Will SPS model staggered retirement at Harrington when operating both on coal and natural gas in its analysis?

A. No. When operating on coal, a staggered early retirement alone will not bring Harrington into compliance with NAAQs. All units will need to be retired, converted to gas or environmental controls installed. SPS's analysis demonstrates that converting the units to gas is more economical than early retirement of the units.

NEXT MEETING

Date: Mid to Late October

Time: Mountain Time TBD

Location: Zoom Meeting

Appendix: Questions For Future Discussions

Sierra Club June 26th Model Input Clarifications

Questions not yet answered will be addressed in future technical conferences

- **Staggered Retirement scenarios:** please confirm that both units will be economically committed and dispatched at all times, and that the no unit's retirement date would be later than 2032.
- **Sustaining Capital Costs:** Does Xcel has a schedule of sustaining capital costs that it plans to incorporate into EnCompass? What is the assumed step-down in spending in years prior to retirement? *
- **Market power**, both firm and non-firm: Is Xcel modeling just resources from the RFP process, or is the Company also planning to model market power as an option to replace some generation and capacity? What cost and availability assumption is Xcel using for these potential purchases? *
- **Environmental Compliance**: What operational assumptions and compliance costs is Xcel planning to using to model Tolk and Harrington's likely environmental compliance obligations?
- **Load and peak assumptions**: What baseline load and peak levels is Xcel using, and what sensitivities does Xcel plan to use in the Tolk analysis, especially in light of COVID's impact on sales and economic activities.

* *Discussed above*

Sierra Club June 26th Model Input Clarifications

- **Optimized modeling vs scenario modeling**: We would like to understand the main factors driving Xcel / EnCompass' selection of optimal retirement date. We believe that optimized retirement runs should be foundation of this analysis. However we would encourage Xcel to also think about hard coding sensitivities based on optimized results to understand how sensitive the model is to specific assumptions. For example, if an optimized run indicates that a 2027 retirement date for Tolk is least cost, but a hard coded retirement of 2025 is only a tiny bit more expensive, is the result of 2027 actually meaningful or is the difference between 2025 and 2027 just a reflection of, for example, the estimated sustaining capital cost assumptions? It is essential that the Company understands and is transparent about which modeling results are significant and which are likely not.*

- **Reliability**: How is Xcel planning to model the firm capacity contribution of solar and wind? Does the Company plan to conduct reliability modeling to inform its ELCC assumptions? Is the Company planning to use resource blocks to reflect the changing contribution of each resource as the amount installed on the system increases? What about paired wind and solar resources? *

* *Discussed above*

Sierra Club June 26th Request for SPS Model Runs

1. Tolk has to comply with Regional Haze regulations by installing dry scrubbers by 2024 (this is likely the earliest there would be any such requirement as it takes at least three years to install).
2. Harrington has to install scrubbers for SO2 NAAQS and/or regional haze compliance by 2024 (same as above). *
3. Harrington operates seasonally *
4. Staggered retirement of both Tolk and Harrington's units (starting as early as possible, likely 2023).
5. Staggered retirement AND seasonal operation of both Tolk and Harrington (seasonal operation stating this year, staggered retirement starting ASAP).
6. Load sensitivity, based in part on COVID impacts, assuming a slow-down in demand growth.

* *Discussed above*

Sierra Club August 20th Request for SPS Model Runs

1. Does SPS plan to use the IRP process to make the final decision on whether to retire, repower on natural gas, or install scrubbers at Harrington? Or does the Company plan to make a decision prior to or outside the IRP process? *
2. When evaluating the least cost solution for Harrington, is SPS evaluating whether it actually has a need for the full capacity and services currently provided by Harrington, or is SPS simply comparing the cost of the plant on natural gas and coal to the cost of providing identical services from alternative resources? *
3. What costs and assumptions for sustaining capital costs is SPS planning to use in its Harrington analysis? *
4. Will the Company assume a reduction in spending in years directly prior to plant retirements? *
5. Does SPS plan to model seasonal operation of Harrington when operating both on coal and natural gas in its analysis? *
6. Will SPS model staggered retirement at Harrington when operating both on coal and natural gas in its analysis? *

* *Discussed above*

Sierra Club August 20th Request for SPS Model Runs

7. Will the Company incorporate the results of its Tolk RFP into its modeling assumptions for Harrington's replacement costs? More specifically, we believe that the Company should use those RFP results (including costs for solar, wind, and battery storage) to inform its cost assumptions for replacing or retrofitting Harrington.

8. When evaluating Harrington, the Company should run at least one scenario requiring compliance with National Ambient Air Quality Standard for sulfur dioxide as expeditiously as practicable, 42 U.S.C. § 7502(c)(1), and no later than 2024. *

9. We urge the Company to run at least one modeling scenario in which Tolk is required to retire, repower, or comply with Regional Haze regulations by installing dry scrubbers or dry sorbent injection by 2024.

* *Discussed above*

Xcel Energy®

Xcel Energy®

2020 Tolk Analysis: Session 3 of the 1st Technical Conference

10/23/2020

Today’s Meeting Agenda

1. Modeling parameters for Harrington Station
    - A. Background & NAAQS compliance
    - B. Harrington operating on gas
    - C. Economic Analysis

Agenda for Future Technical Conferences

1. Tolk Analysis – Retirement dates and operating scenarios
2. Value of Tolk water rights
3. Modeling Parameters

BACKGROUND & NAAQS COMPLIANCE

Xcel Energy®

Background

- NM Rate Case Stipulation states “*SPS also commits to running at least one scenario in which all of SPS’s coal-burning units are retired or replaced before 2030*”
- Harrington Station:
  - Three coal-fired units: each ~340MW
  - Located North of Amarillo, Texas
  - Units 1 – 3 are scheduled to retire 2036, 2038 & 2040, respectively
- SPS intend to run every scenario in the Tolk Analysis in which all three Harrington units are converted to operate on natural gas by 2025

NAAQS

- The Clean Air Act requires the EPA to set National Ambient Air Quality Standards (including SO2)
- The TCEQ classified the area as Attainment/Unclassifiable due to a lack of monitoring data in the area
- In December 2016, TCEQ installed an SO2 monitor in the vicinity of Harrington Station to collect ambient air data
- Readings from the monitor exceed the standards
- Harrington emits ~99% of the SO2 emissions in Potter County
- Emphasis will be on SPS to produce implementation plan
- Anticipated compliance date: By 2025
- Agreed Order October 2020

Compliance Solutions

- Installation of environmental controls on three units*
- Early retirement of all three units (EOY 2024)
- Conversion of all three units to natural gas
- Combination of the above

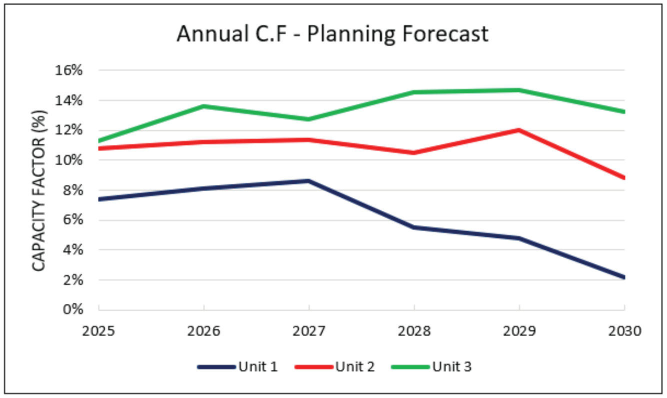
**Installation of environmental controls is cost prohibitive. Based on feedback from previous technical conferences environmental controls will not be presented today*

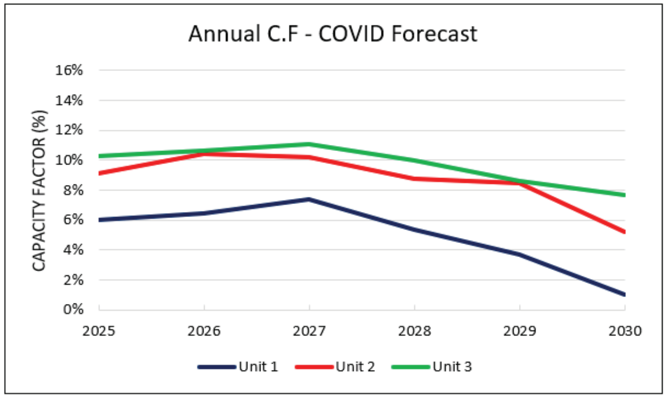
HARRINGTON OPERATING ON GAS

Harrington on Gas

- Fuel change only
- Low cost solution to:
  - Meet NAAQs compliance
  - Continue to provide over 1,000MW of year-round capacity
- System reliability benefits
- After the conversion to gas, the Harrington units act as "peaking" generation
  - Low capacity factors
  - Provide energy during times of high demand or low renewable output

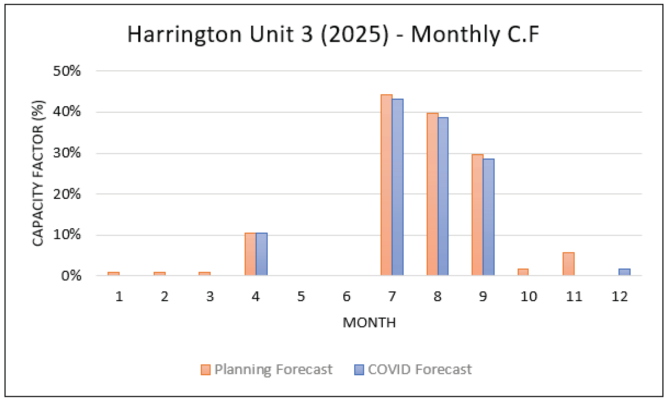
Low Annual Capacity Factors

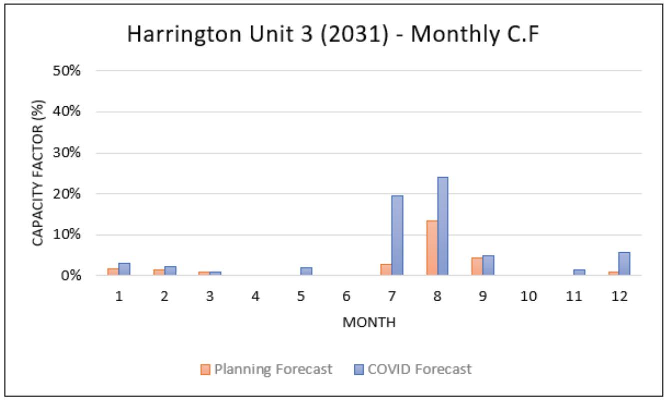

Annual C.F - Planning Forecast


Annual C.F - COVID Forecast

- The Harrington Units will provide “peaking generation” with projected capacity factors <10 - 15% depending on load forecast

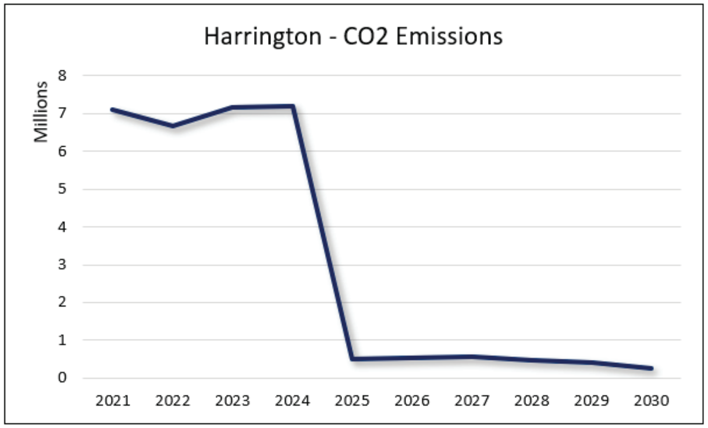
Capacity Factors by Month





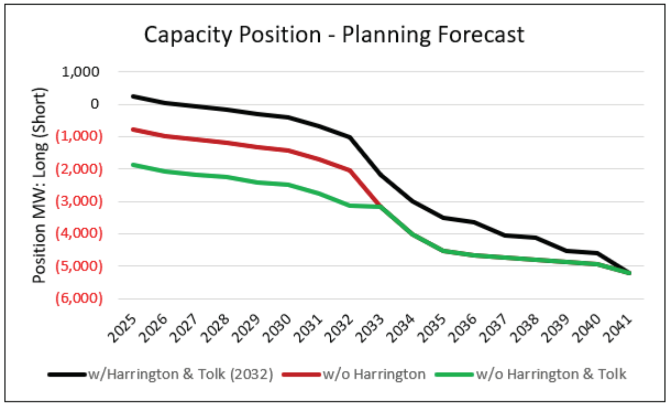
- In the near term, Harrington will provide generation during the peak Summer months
- Harrington will support the integration of new renewables by providing energy during hours of low renewable generation

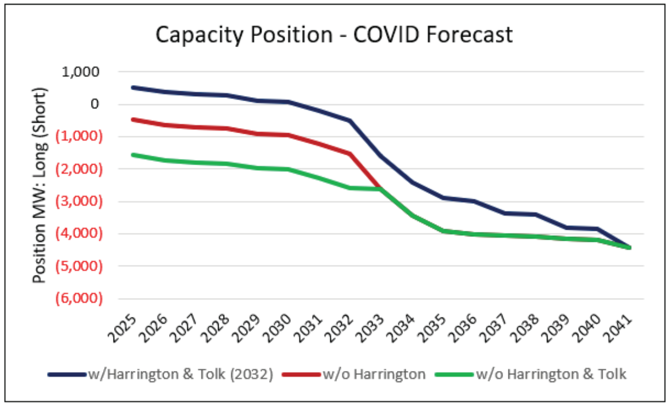
Harrington Annual CO2 Emissions



- Converting Harrington to gas lowers CO2 emissions by ~95% over a 10-year period
- Reduction is the result of lower CO2 intensity and a low capacity factor

Summary Capacity Position


Capacity Position - Planning Forecast


Capacity Position - COVID Forecast

- Including Tolk & Harrington, SPS has sufficient capacity until between 2027 & 2031 depending on load forecast
- Retiring Harrington EOY 2024 will create an immediate capacity need of between ~500MW and 800MW, rising to between ~1,000MW and 1,400MW by 2030
- Retiring both Tolk and Harrington EOY 2024 will create an immediate capacity need of between ~1,600MW and 1,900MW rising to between ~2,000MW and 2,400MW by 2030

Retiring Gas Generation

- SPS's entire fleet of gas steam generation (1,624MW) is scheduled to retire by EOY 2034
- 1,138MW is scheduled to retire by EOY 2030
- Harrington Station provides 1,021MW of capacity
- Tolk Station provides 1,069MW of capacity
- Potentially 3,228MW of thermal generation could be retired by 2030
- SPS owns 4,335MW of thermal generation
- Retiring this amount of thermal generation will require new thermal generation

Xcel Energy®

Economic Analysis

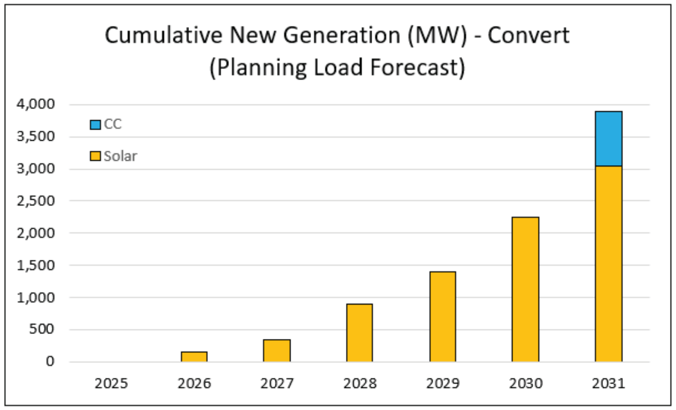
Economic Analysis

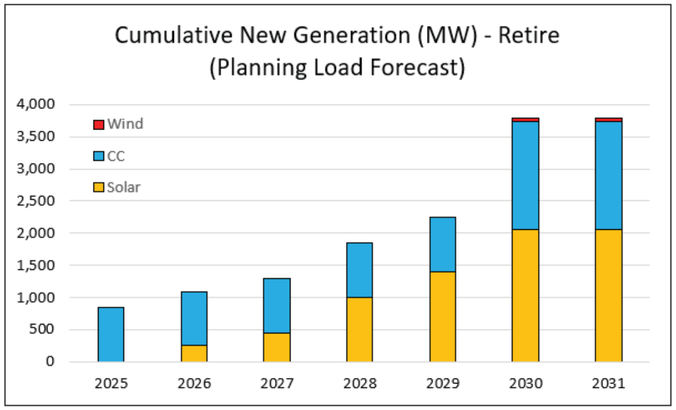
Planning Forecast		
PVRR Production Cost	Delta ($M)	NPV ($M) 2021-2049
Convert Units to Gas	$0	$16,045
Early Retirement (2024)	$116	$16,161

COVID Forecast		
PVRR Production Cost	Delta ($M)	NPV ($M) 2021-2049
Convert Units to Gas	$0	$13,951
Early Retirement (2024)	$76	$14,027

- Converting the units to gas saves between $76M - $116M (PVRR) when compared to an early retirement
- The Encompass model:
  - Added more new renewable generation by 2031 when converting the units to gas
  - Added an additional combined cycle unit when retiring Harrington EOY2024

Expansion Plans – Planning Forecast



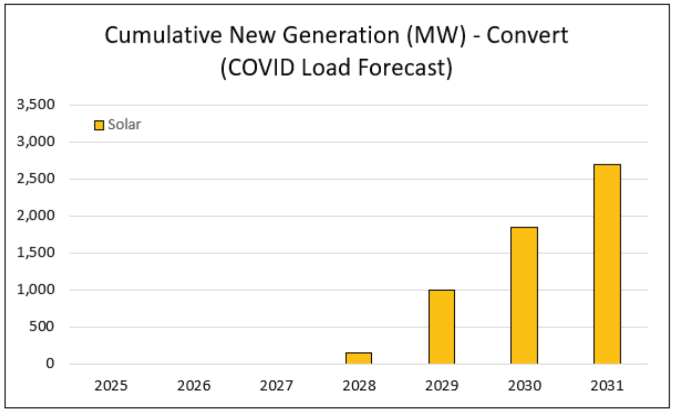


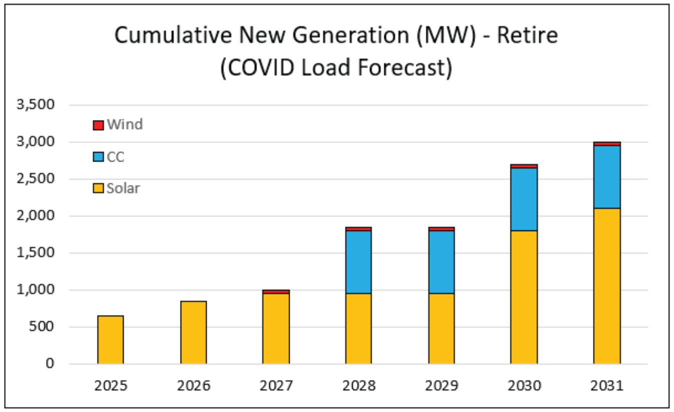
- When converting to gas (left graph), the Encompass model added 3,050MW of new solar and a combined cycle by EOY 2031
- When retiring the Harrington Units (right graph), the Encompass model added 2,050MW of solar, 50MW of wind and two combined cycles by EOY 2031

DRAFT

Expansion Plans – COVID Forecast

DRAFT


Cumulative New Generation (MW) - Convert
(COVID Load Forecast)


Cumulative New Generation (MW) - Retire
(COVID Load Forecast)

- When converting to gas (left graph), the Encompass model added 2,700MW of solar by EOY 2031
- When retiring the Harrington Units (right graph), the Encompass model added 2,100MW of solar, 50MW of wind and a combined cycle by EOY 2031

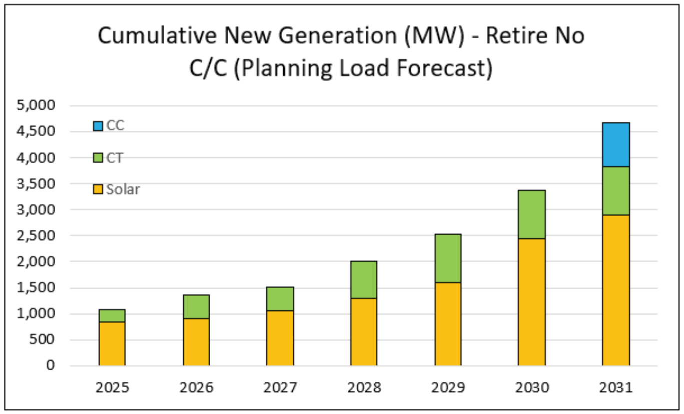
Economic Analysis (w/o CC)

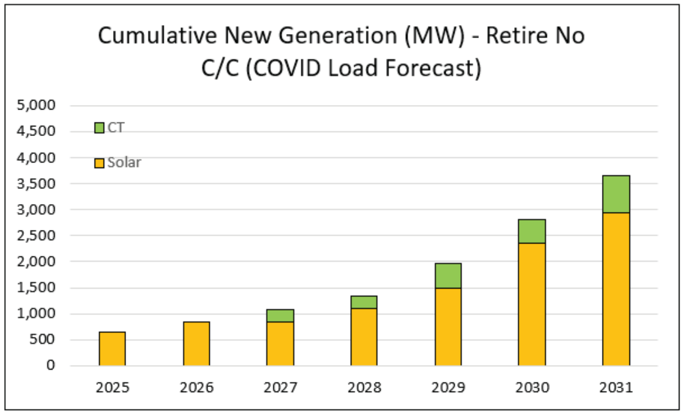
Planning Forecast		
PVRR Production Cost	Delta ($M)	NPV ($M) 2021-2049
Convert Units to Gas	$0	$16,045
Early Retirement (2024)	$116	$16,161
Early Retirement (2024) - No CC	$364	$16,409

COVID Forecast		
PVRR Production Cost	Delta ($M)	NPV ($M) 2021-2049
Convert Units to Gas	$0	$13,951
Early Retirement (2024)	$76	$14,027
Early Retirement (2024) - No CC	$206	$14,157

- The economic analysis was recalculated restricting encompass from adding a combined cycle before EOY 2030
- Converting the units to gas saves between $206M - $364M (PVRR) when compared to an early retirement

Expansion Plan w/o CC before 2030





- Depending on the load forecast, when retiring Harrington and restricting the model from adding a CC before EOY 2030, it added between:
- 2,900MW of solar, 4 CTs and 1 combined cycle, and
- 2,950MW of solar and 3 CTs

DRAFT

Economic Analysis (w/o CC/CT)

DRAFT

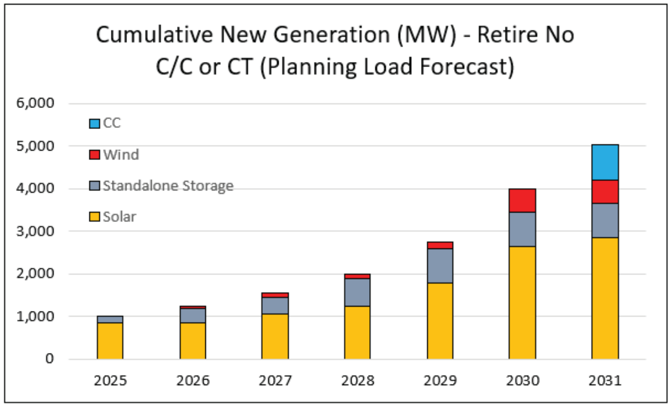
Planning Forecast		
PVRR Production Cost	Delta ($M)	NPV ($M) 2021-2049
Convert Units to Gas	$0	$16,045
Early Retirement (2024)	$116	$16,161
Early Retirement (2024) - No CC	$364	$16,409
Early Retirement (2024) - No CT/CC	$1,345	$17,390

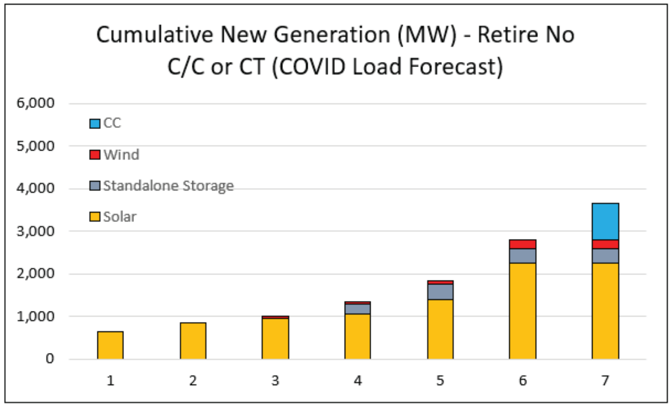
COVID Forecast		
PVRR Production Cost	Delta ($M)	NPV ($M) 2021-2049
Convert Units to Gas	$0	$13,951
Early Retirement (2024)	$76	$14,027
Early Retirement (2024) - No CC	$206	$14,157
Early Retirement (2024) - No CT/CC	$397	$14,348

- The economic analysis was once again re-run restricting encompass from selecting a combined cycle or combustion turbines before EOY 2030
- Converting the units to gas saves between $397M - $1,345M (PVRR) when compared to an early retirement

DRAFT DRAFT

Expansion Plan w/o CC/CT before 2030


Cumulative New Generation (MW) - Retire No C/C or CT (Planning Load Forecast)


Cumulative New Generation (MW) - Retire No C/C or CT (COVID Load Forecast)

- Depending on the load forecast, when retiring Harrington and restricting the model from adding a CC or CTs before EOY 2030, it added between:
- 800MW of storage, 550MW of wind, 2,850MW of solar, and a CC in 2031
- 350MW of storage, 200MW of wind, 2,250MW of solar, and a CC in 2031

Summary

- Converting the Harrington Units to operate on natural gas:
  - ➢ Is a low cost and low risk solution for NAAQs compliance
  - ➢ Is the lowest cost alternative compared to other compliance strategies
  - ➢ Provides year-round capacity and generation, benefitting the integration of additional renewables onto the SPS system
  - ➢ Carbon Emissions at Harrington Station are reduced by ~95% over a 10-year period

Xcel Energy®

Tolk Analysis: Session 4 of the 1st Technical Conference

02/08/2021

Today's Agenda

1. Recap prior technical conferences
2. Tolk Analysis – Final proposed retirement dates and operating scenarios
3. Replacement Resources in the Encompass Model
4. Critical Modeling Parameters / Sensitivities
5. Value of Tolk water rights
6. Summary of 1st Technical Conference
7. Final review of questions previously submitted by Sierra Club

Xcel Energy®

RECAP OF PRIOR TECHNICAL CONFERENCES

Recap - Overview

Technical Conferences

“SPS shall hold two technical conferences located in either Santa Fe or Albuquerque, NM. ***The first technical conference will be for SPS to present and solicit feedback on the basic parameters and approach of its analysis****. The second technical conference will be for SPS to provide and solicit feedback on the preliminary conclusions of its analysis”*

Subsequent Changes

- COVID-19 required technical conferences to be held virtually
- SPS proposed splitting the first technical conference into multiple sessions - with today being the fourth and final session of the 1st Technical Conference

Recap – 1st Session

1. General approach of the Tolk Analysis
    - PVRR Analysis using the Encompass production cost modeling software
    - Evaluate multiple retirement and operating scenarios – each with an optimized expansion and generator replacement plan
    - Type, technical characteristics, and cost of replacement generation will be the result of an RFI process
    - An Independent Evaluator ("IE") will oversee the RFI process and Tolk Analysis
2. Request for Proposal ("RFP") to acquire the services of an IE

   *Guidehouse was subsequently appointed as IE
3. Draft Request for Information ("RFI") to obtain pricing of replacement resources

   *RFI was subsequently issued and proposals received on November 6th, 2020
4. Outline of the scenarios SPS is proposing to evaluate

Recap – 2nd Session

1. Prior and Future Technical Conferences
2. Updates from Prior Technical Conference
    - A. Independent Evaluator
    - B. Request for Information for generating resources
3. Encompass – Production Cost Modeling Software
4. Responses to Parties Comments and Questions
    - A. SPS Load Forecast Update
    - B. Sierra Club Modeling Questions (outstanding questions to be addressed today)

Recap – 3rd Session

1. Modeling parameters for Harrington Station
   - A. Background & NAAQS compliance
   - B. Harrington operating on gas
   - C. Economic Analysis

TOLK ANALYSIS – RETIREMENT DATES AND OPERATING SCENARIOS

Operating & Retirement Scenarios

After originally presenting the Operating & Retirement Scenarios in the 1st Session of the 1st Technical Conference, SPS has reviewed the feedback provided and propose the following operating and retirement scenarios:

- Scenario 1 – Annual Economic Dispatch
  - ➢ Summer only economic dispatch throughout 2021
  - ➢ Annual economic dispatch thereafter
  - ➢ Both units retire at end of economically available water (~2025 – 2026)
  - ➢ Harrington converted to gas EOY2024

- Scenario 2 – Summer Only Economic Dispatch
  - ➢ Summer only economic dispatch 2021 and beyond
  - ➢ Both units retire at end of economically available water (~2032)
  - ➢ Harrington converted to gas EOY2024

Operating & Retirement Scenarios

- Scenario 3 – Earliest Retirement of Tolk Units (2023)
  - ➢ Summer only economic dispatch 2021
  - ➢ Annual economic dispatch thereafter (2022 & 2023)
  - ➢ Harrington converted to gas EOY2024

- Scenario 4 – Staggered Retirement of Tolk Units

  - ➢ Unit 1 retires EOY 2023
  - ➢ Unit 2 retires at end of economically available water (~2031)
  - ➢ Summer only economic dispatch 2021
  - ➢ Annual economic dispatch thereafter
  - ➢ Harrington converted to gas EOY2024

Operating & Retirement Scenarios

- Scenario 5 – Staggered Retirement of Tolk Units (2023) & Seasonal Operations
  - Unit 1 retires EOY 2023
  - Unit 2 retires EOY 2032
  - Summer only economic dispatch
  - Harrington converted to gas EOY2024
- Scenario 6 – Earliest Retirement of Tolk & Harrington Units
  - All Tolk and Harrington Units Retire EOY 2023
  - Tolk - Summer only economic dispatch 2021
  - Tolk - Annual economic dispatch thereafter
  - Harrington – Annual economic dispatch in all years

Sierra Club Requested Scenarios

(Staggered Retirements)

Staggered retirement of both Tolk and Harrington's units (starting as early as possible, likely 2023)

Scenario 4 incorporates a staggered retirement of the Tolk Units. As discussed in previous technical conferences, the Harrington Units are required to comply with NAAQS by EOY2024. A staggered retirement of the Harrington Units would not meet NAAQS compliance. Scenario 6 incorporates an early retirement of all Tolk and Harrington units.

Staggered retirement AND seasonal operation of both Tolk and Harrington (seasonal operation starting this year, staggered retirement starting ASAP).

Added Scenario 5 to incorporate this request for the Tolk Units. However, as previously discussed, seasonal operations of the Harrington units will not meet NAAQS compliance.

Staggered Retirement scenarios: please confirm that both units will be economically committed and dispatched at all times, and that the no unit's retirement date would be later than 2032

Confirmed, to the extent of this Tolk Analysis

Sierra Club Requested Scenarios

(Environmental Controls)

Tolk has to comply with Regional Haze regulations by installing dry scrubbers by 2024 (this is likely the earliest there would be any such requirement as it takes at least three years to install)

SPS has recently evaluated the installation of scrubbers and dry sorbent injection on the Harrington units to comply with NAAQS. As presented in the 3rd session of the 1st technical conference, the installation of capital-intensive environmental controls is cost prohibitive for the Harrington Units. Based on current modeling inputs, the same conclusion can almost certainly be applied to the Tolk Units. If SPS is required to comply with Regional Haze regulations, or any other regulations that require environmental controls, SPS will reevaluate the retirement date(s) of the units at that time.

Run at least one modeling scenario in which Tolk is required to retire, repower, or comply with Regional Haze regulations by installing dry scrubbers or dry sorbent injection by 2024

See previous response.

Environmental Compliance: What operational assumptions and compliance costs is Xcel planning to use to model Tolk and Harrington's **likely** environmental compliance obligations?

See previous response.

Xcel Energy®

REPLACEMENT RESOURCES

Generator Replacement Resources

- The Encompass model will create an optimized expansion plan / generator replacement plan for each of the scenarios previously described
- Resources proposed in the RFI process will be available for optimized selection by Encompass (including selection solely for economic energy benefits), generally, this is through EOY 2025
- Thereafter ‘generic-priced’ resources will be available for selection, including but not limited to, solar, wind, simple cycle combustion turbines, battery storage, and combined cycle gas generation

RFI Replacement Resources

- SPS received information from nearly 20 different bidders
- Proposals included approximately 75 different pricing structures
- Majority of proposals were either solar, solar + storage or wind projects
- Other technology included: combined cycle generation with hydrogen production and storage, gravitational energy storage, compressed air storage
- Commercial operation dates generally ranged from 2022 to 2025
- Project output ranged from 25MW to 1,100MW+

MODELING PARAMETERS / SENSITIVITY ANALYSIS

Gas Forecast Methodology

Gas Forecast

The price of natural gas is a significant variable. SPS uses a combination of market prices and fundamental price forecasts, based on multiple highly respected, industry leading sources, to calculate monthly delivered gas prices. As the foundation of the gas price forecast, Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange (“NYMEX”) futures prices) and long-term fundamentally based forecasts from Wood Mackenzie, IHS Energy, and S&P Global. The forecast is fully market-based for the first few years, then transitions into blending the four sources to develop a composite forecast. The Henry Hub forecast is adjusted for regional basis differentials and specific delivery costs for each generating unit to develop final model inputs.

SPS will use the company’s 1H21 gas forecast in the Tolk Analysis. The 1H21 gas forecast is expected to be released in March 2021.

Gas Forecast Sensitivity

Gas Forecast Sensitivity

SPS will conduct low and high gas price forecast sensitivity analyses. For the low and high price cases, the base gas forecast for Henry Hub is 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.

Market Price Forecast Methodology

Market Price Forecast

In addition to resources that exist within SPS's service territory, SPS has access to a regional market located outside its service territory. SPS is a member of the SPP, which operates as a consolidated balancing authority and dispatches all available generation resources within its boundaries. This consolidated dispatch allows SPS access to energy resources outside SPS's service territory for purchases, as well as the opportunity to sell from its generating sources to other market participants. SPS uses a simple average of long-term on-peak and off-peak implied heat rate forecasts provided by Wood Mackenzie, S&P Global and IHS Markit for SPP South Hub. The implied heat rates, denominated in million British thermal units/megawatt-hour, are then multiplied by SPS's long-term natural gas price forecast to convert the implied heat rate values into energy prices. This process is repeated for all months, distinguishing between on and off-peak prices, through the end of the modeling period.

SPS will use the company's 1H21 market price forecast in the Tolk Analysis. The 1H21 market price forecast is expected to be released in March 2021.

Market Price Forecast Sensitivity

Market Price Forecast Sensitivities

SPS’s market price forecast is dependent on the gas price forecast used. As such, the market price forecast will be adjusted with the low and high gas sensitivity analyses

As preliminary results become available, SPS may analyze additional market price sensitivities depending on the optimized generation portfolio’s reliance on purchases from, or sales to, the SPP integrated market.

Demand and Energy Forecast Methodology

Demand and Energy Forecast

Projections of future energy sales and coincident peak demand are fundamental inputs into SPS's resource need assessment. SPS forecasts retail energy sales and customers by rate class for each jurisdiction. Retail coincident peak demand is forecasted in the 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 on a monthly basis and uses monthly historical data to develop the customer, 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.

SPS will use the company's Spring 2021 sales and demand forecast in the Tolk Analysis.

Demand and Energy Forecast Sensitivity

Demand and Energy Forecast

Development and use of different energy sales and demand forecasts for planning future resources is an important aspect of the planning process. SPS will conduct sensitivity analyses using a high and low forecast. The high and low forecasts 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.

Xcel Energy®

TOLK WELLFIELD WATER VALUATION

RICHARD L. BELT, DIRECTOR – CHEMISTRY & WATER RESOURCES

Tolk Overview and Water Transaction Background

- ~50,000 acres, entirely within Lamb County
- SPS does not own the surface estate, except at plant sites
- Saturated thickness from <30 ft to >70 ft (generally from west to east)

- Rule of capture – entitled to groundwater under surface estate, not volume certain
- Groundwater right can be severed from surface estate
- Local groundwater districts establish production limits, spacing rules, reporting requirements

- Sold on per-acre basis vs. per-acre foot basis
- Value of any surface improvements conveyed with sale (i.e. wells)
- Water value = value of irrigated acreage minus value of dry acreage, adjusting for improvements or other considerations (TX/NM are non-disclosure states, a complication)
- Other adjustments needed?, i.e. groundwater depletion
- HPWD annual groundwater depreciation study

Critical Assumptions

- Acres with <40 feet of saturated thickness should be excluded from valuation estimate

- Need for conveyance system and details (deduction)
- Municipal buyer may need to replace all wells not completed to TCEQ standard (deduction)
- Prospective buyer pool limitation (negotiation limitation)
- Lower water right valuation bound is $0

- Time to identify a buyer, close the transaction, and develop a conveyance system?
- Per HPWD, Lamb County water valuation declined 40% from 2016 to 2020
- Rate of future saturated thickness decline & growth of excluded acreage?
- Seasonal vs. year-round generation & impact on available water

- Future site optionality may be highest/best value for ratepayers

Recommended Approach to Water Valuation

- Adjust HPWD water valuation
- Estimate wellfield acreage with depleted groundwater based on latest groundwater model
- Establish Tolk operational assumptions during the preceeding period

- Use HPWD water valuation with appropriate adjustment
- Multiply by wellfield acreage as adjusted for depleted groundwater
- Evaluate assumption sensitivities

- Engage a local Realtor or general appraiser to assess comparable Lamb County irrigated and dryland acreage to establish water value, including infrastructure adjustment.
- Multiply by wellfield acreage as adjusted for depleted groundwater
- Evaluate assumption sensitivities

SUMMARY OF 1ST TECHNICAL CONFERENCE

First Technical Conference Summary

The first technical conference will be for SPS to present and solicit feedback on the basic parameters and approach of its analysis

- Present Value Revenue Requirement (PVRR) analysis conducted in Encompass model
- Evaluate multiple operating parameters and retirement dates for the Tolk Units
- Model incorporates the technical characteristics, operating parameters, cost, retirement dates etc. of SPS's existing generation fleet
- Each scenario will incorporate an optimized generator expansion / replacement plan
- Generator expansion / replacement plan will be based on the proposals received in the RFI process
- Independent Evaluator will oversee the Tolk Analysis
- [

First Technical Conference Summary

The first technical conference will be for SPS to present and solicit feedback on the basic parameters and approach of its analysis

- Critical inputs, such as gas prices, market prices, energy and demand forecasts will be evaluated using sensitivity analyses

Xcel Energy®

FINAL REVIEW OF QUESTIONS PREVIOUSLY SUBMITTED BY SIERRA CLUB

Sierra Club June 26th Model Input Clarifications

- **Staggered Retirement scenarios:** please confirm that both units will be economically committed and dispatched at all times, and that the no unit's retirement date would be later than 2032**
- **Sustaining Capital Costs:** Does Xcel have a schedule of sustaining capital costs that it plans to incorporate into EnCompass? What is the assumed step-down in spending in years prior to retirement? *
- **Market power, both firm and non-firm:** Is Xcel modeling just resources from the RFP process, or is the Company also planning to model market power as an option to replace some generation and capacity? What cost and availability assumption is Xcel using for these potential purchases? *
- **Environmental Compliance**: What operational assumptions and compliance costs is Xcel planning to use to model Tolk and Harrington's likely environmental compliance obligations?**
- **Load and peak assumptions**: What baseline load and peak levels is Xcel using, and what sensitivities does Xcel plan to use in the Tolk analysis, especially in light of COVID's impact on sales and economic activities**
- **Responses provided in prior technical conferences*
- *** Responses provided in this technical conference*

Sierra Club June 26th Model Input Clarifications

- **Optimized modeling vs scenario modeling**: We would like to understand the main factors driving Xcel / EnCompass' selection of optimal retirement date. We believe that optimized retirement runs should be foundation of this analysis. However we would encourage Xcel to also think about hard coding sensitivities based on optimized results to understand how sensitive the model is to specific assumptions. For example, if an optimized run indicates that a 2027 retirement date for Tolk is least cost, but a hard coded retirement of 2025 is only a tiny bit more expensive, is the result of 2027 actually meaningful or is the difference between 2025 and 2027 just a reflection of, for example, the estimated sustaining capital cost assumptions? It is essential that the Company understands and is transparent about which modeling results are significant and which are likely not.*

- **Reliability**: How is Xcel planning to model the firm capacity contribution of solar and wind? Does the Company plan to conduct reliability modeling to inform its ELCC assumptions? Is the Company planning to use resource blocks to reflect the changing contribution of each resource as the amount installed on the system increases? What about paired wind and solar resources? *

* *Responses provided in prior technical conferences*

** *Responses provided in this technical conference*

Sierra Club June 26th Request for SPS Model Runs

1. Tolk has to comply with Regional Haze regulations by installing dry scrubbers by 2024 (this is likely the earliest there would be any such requirement as it takes at least three years to install).**
2. Harrington has to install scrubbers for SO2 NAAQS and/or regional haze compliance by 2024 (same as above). *
3. Harrington operates seasonally. *
4. Staggered retirement of both Tolk and Harrington's units (starting as early as possible, likely 2023).**
5. Staggered retirement AND seasonal operation of both Tolk and Harrington (seasonal operation starting this year, staggered retirement starting ASAP).**
6. Load sensitivity, based in part on COVID impacts, assuming a slow-down in demand growth.**

* *Responses provided in prior technical conferences*

** *Responses provided in this technical conference*

Sierra Club August 20th Request for SPS Model Runs

1. Does SPS plan to use the IRP process to make the final decision on whether to retire, repower on natural gas, or install scrubbers at Harrington? Or does the Company plan to make a decision prior to or outside the IRP process? *
2. When evaluating the least cost solution for Harrington, is SPS evaluating whether it actually has a need for the full capacity and services currently provided by Harrington, or is SPS simply comparing the cost of the plant on natural gas and coal to the cost of providing identical services from alternative resources? *
3. What costs and assumptions for sustaining capital costs is SPS planning to use in its Harrington analysis? *
4. Will the Company assume a reduction in spending in years directly prior to plant retirements? *
5. Does SPS plan to model seasonal operation of Harrington when operating both on coal and natural gas in its analysis? *

* *Responses provided in prior technical conferences*

** *Responses provided in this technical conference*

Sierra Club August 20th Request for SPS Model Runs

6. Will SPS model staggered retirement at Harrington when operating both on coal and natural gas in its analysis? *

7. Will the Company incorporate the results of its Tolk RFP into its modeling assumptions for Harrington's replacement costs? More specifically, we believe that the Company should use those RFP results (including costs for solar, wind, and battery storage) to inform its cost assumptions for replacing or retrofitting Harrington.**

8. When evaluating Harrington, the Company should run at least one scenario requiring compliance with National Ambient Air Quality Standard for sulfur dioxide as expeditiously as practicable, 42 U.S.C. § 7502(c)(1), and no later than 2024. *

9. We urge the Company to run at least one modeling scenario in which Tolk is required to retire, repower, or comply with Regional Haze regulations by installing dry scrubbers or dry sorbent injection by 2024.**

* *Responses provided in prior technical conferences*

** *Responses provided in this technical conference*

Xcel Energy®

Tolk Analysis: 2nd Technical Conference

04/19/2021

Agenda

2nd Technical Conference

1. Introduction
2. Tolk Analysis Overview
3. SPS System Overview
4. Conclusion 1: Replacement Resources
5. Conclusion 2: Preliminary Results
6. Final Review

Preliminary Results

Disclaimer

The results presented today are preliminary and are subject to change

Xcel Energy / SPS will release a new natural gas forecast between now and filing the Tolk Analysis. SPS will update the results preliminary results presented today to incorporate the new natural gas forecast in the final analysis

INTRODUCTION

Introduction

Stipulation

The uncontested comprehensive stipulation in New Mexico Case No. 19-00170-UT requires SPS to submit a robust analysis of Tolk abandonment and potential means of replacement by June 2021 (“The Tolk Analysis”)

- The Tolk Analysis will be incorporated into SPS’s 2021 Integrated Resource Plan (“IRP”) application
- The Tolk Analysis shall include:
  - **Two technical conferences**
  - A review by an independent evaluator (“IE”)
  - **Replacement resources priced based on an RFP or RFI process**

Introduction

Technical Conferences

- First Technical Conference – Present and solicit feedback on the basic parameters and approach of the Tolk analysis
  - Completed four technical conferences between June 2020 and February 2021
- **Second Technical Conference – Provide and solicit feedback on the preliminary conclusions of the Tolk analysis**

Introduction

Replacement resources priced based on an RFP or RFI process

- The intent of the 2020 request for information (“RFI”) is to provide SPS with the type, technical characteristics, and cost of the resources needed or available to conduct the Tolk Analysis
- The expansion plans presented today are only intended to demonstrate how the Encompass model selected different portfolios of resources to potentially replace, or supplement, the capacity and energy provided by the Tolk Units
- As discussed during this presentation, the Tolk Analysis incorporates several critical variables and external drivers that impact the quantity and timing of potential additional resources
- If applicable, SPS will conduct a thorough and separate procurement process before acquiring any additional resources
- The selection of proposals in the Tolk Analysis will have no bearing on any possible future procurement process

Introduction

Preliminary Conclusions

Conclusion 1 – Resources Submitted in the RFI Process

- The Tolk analysis provides indication that SPS should continue to explore the acquisition of economic energy resources
- Potential cost savings provided by new resources are highly dependent on critical variables and external drivers

Conclusion 2 – Retirement of the Tolk Units

- The preliminary results of the Tolk Analysis do not conclusively support an earlier retirement of the Tolk Units
- Without clear and obvious data to the contrary, SPS recommends continued operation of the Tolk units on a seasonal basis through end-of-year 2032

Note: The two conclusions are not mutually exclusive

THE TOLK ANALYSIS OVERVIEW

Tolk Analysis Overview

Tolk Station – Overview of Benefits & Costs

Benefits captured in Encompass

- Relatively low-cost, *dispatchable* energy
- Over 1GW of year-round capacity

Costs captured in Encompass (not exhaustive)

- Cost Recovery of Capital Investment
- Fixed Costs
  - ➢ Operations and Maintenance (labor expenses, maintenance, coal handling etc.)
- Variable Costs
  - ➢ Operations and Maintenance (chemicals, water)
  - ➢ Fuel Costs

Tolk Analysis Overview

Objective

Establish the optimal operation and retirement dates of the Tolk Units, considering availability of economical water. The Tolk Analysis evaluates alternative benefits (and costs) provided by the Tolk Units:

1. **Maximize Energy Value**
   - ➢ Continue to operate the Tolk units year-round (economically) – at the expense of an earlier retirement date, or
2. **Preserve Capacity Value**
   - ➢ Preserve Tolk's >1GW capacity – at the expense of deferred energy production, or
3. **Is There a More Optimal Approach? (i.e Early Retirement)**
   - ➢ Retire the Tolk Units early – regardless of the availability of economic water
   - ➢ Obtain capacity and energy from alternative resources

Tolk Analysis Overview

Scenarios

Maximize Energy Value

- **Scenario 1**
  - Operate the Tolk Units year-round (economically)
  - Retire Tolk units EOY2025

Preserve Capacity Value

- **Scenario 2**
  - Operate the Tolk Units seasonally (economically)
  - Retire Tolk units EOY2032

Early Retirement

- **Scenario 3**
  - Operate the Tolk Units year-round (economically)
  - Retire Tolk units EOY2023
- **Scenario 6**
  - Operate the Tolk & Harrington Units year-round (economically)
  - Retire all units EOY2023

Hybrid Approach

- **Scenario 4**
  - Operate the Tolk Units year-round (economically)
  - Retire Tolk unit 1 EOY2023
  - Retire Tolk unit 2 EOY2031
- **Scenario 5**
  - Operate the Tolk Units seasonally (economically)
  - Retire Tolk unit 1 EOY2023
  - Retire Tolk unit 2 EOY2032

Throughout todays presentation, Scenarios 2 & 3 will be used to demonstrate SPS's preliminary conclusions

Xcel Energy®

SPS SYSTEM OVERVIEW

SPS System Overview

Capacity & Planning Reserve Margin

- To provide reliable service, all electric utilities must have more capacity available than the projected peak load
- The available capacity in excess of the projected peak load is referred to as the “ planning reserve margin” (“PRM”)
- SPS is a member of the Southwest Power Pool (“SPP”)
- SPP requires each member to have a planning reserve margin of at least 12% of its peak demand forecast
- SPS’s current Summer Peak demand is approximately 4,000MW
- Including the PRM, SPS are required to have a ***minimum*** of ~4,500MW of accredited capacity to meet Summer Peak Demand

SPS System Overview

Meeting the capacity need

- SPS currently has sufficient accredited capacity through the late 2020's to early 2030's
- The early retirement of the Tolk Units will create an immediate capacity need – requiring SPS to acquire additional resources
- Renewable resources are treated as contributing towards SPS's projected peak load (although not 100% of the nameplate capacity), for example:
  - Wind accredited capacity towards the Summer peak is ~20%
  - Solar accredited capacity towards the Summer peak is ~55%
- SPS must be able to serve *load in all hours, during variable weather conditions* – therefore, firm resources or long-duration energy storage will be required

SPS System

Firm Resources / Fuel Diversity

- For the purposes of the Encompass analysis, SPS utilize standard modeling inputs, such as weather-normalized load forecasts and average annual production profiles
- While extreme events like Winter Storm Uri are not fully captured in capacity/price modeling, this uncertainty is captured as part of our planning reserve
- During this cold-weather event, the Tolk and Harrington units were critical in serving SPS's customers and as a hedge against high energy prices
  - *Between 2/13/2021 and 2/19/2021 the Tolk and Harrington units produced ~270,000 MWh*
  - *Cost of energy was between $19.00 - $20.00 / MWh*
  - *Without Tolk and/or Harrington SPS would have incurred much greater costs to dispatch other resources or purchase from the market*

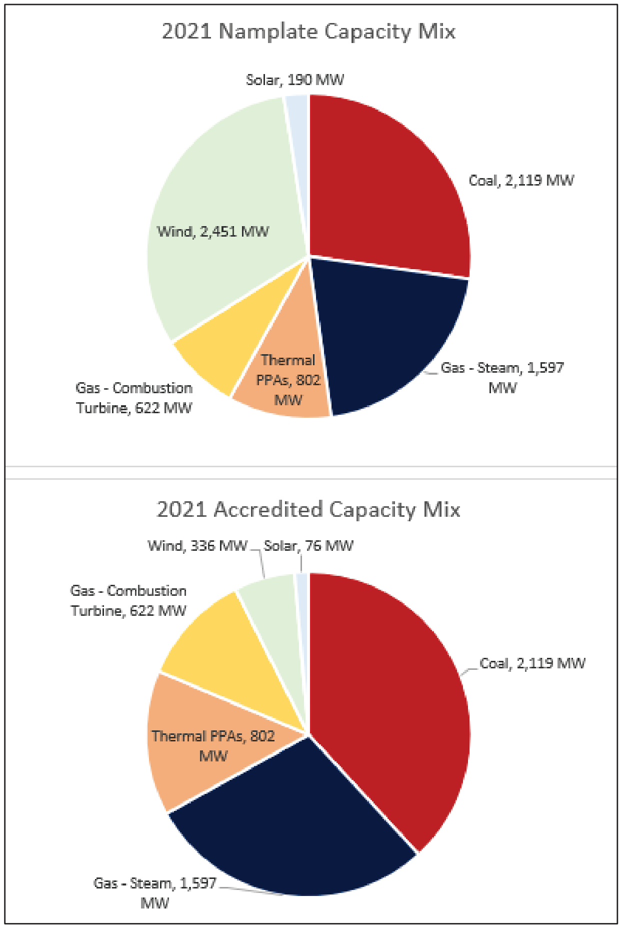
SPS System Overview

Existing System

SPS currently has:

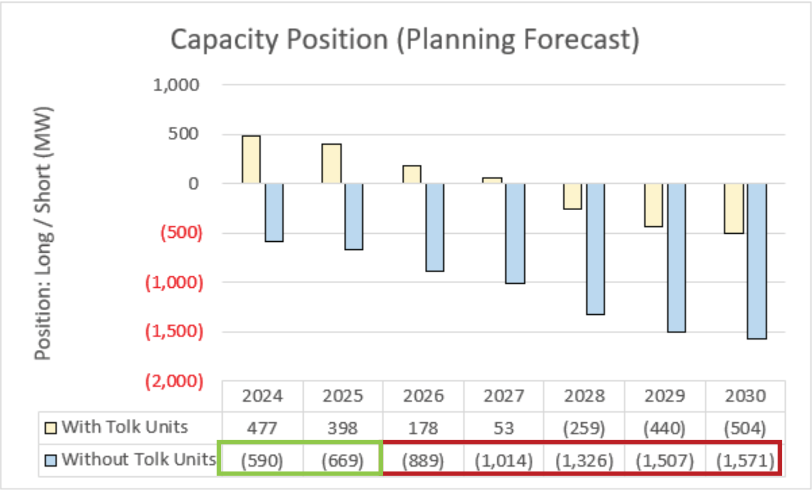
- 7,781MW of generating resources
  - ➢ 5,140MW of firm resources
  - ➢ 2,641MW of wind and solar resources
- 5,548MW of accredited summer capacity

- *1,600MW of gas steam generation*
  - *1,100MW scheduled to retire by EOY 2030*
  - *1,350MW scheduled to retire by EOY 2032*

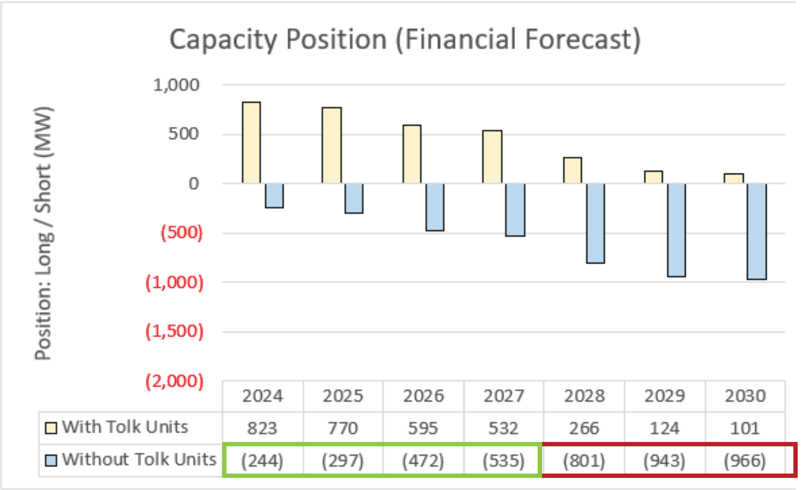


SPS System

Capacity Position



	2024	2025	2026	2027	2028	2029	2030
☐ With Tolk Units	477	398	178	53	(259)	(440)	(504)
☐ Without Tolk Units	(590)	(669)	(889)	(1,014)	(1,326)	(1,507)	(1,571)



	2024	2025	2026	2027	2028	2029	2030
☐ With Tolk Units	823	770	595	532	266	124	101
☐ Without Tolk Units	(244)	(297)	(472)	(535)	(801)	(943)	(966)

- As discussed in detail in the next section, all scenarios modeled add significant renewable generation between 2023 and 2025
- Generally, the accredited capacity of the new renewable generation initially fulfills the lost capacity of the Tolk Units (green). However, the Encompass model then adds firm resources (combined cycles, combustion turbines, or energy storage) as this need increases (red)

CONCLUSION 1 – RESOURCES SUBMITTED IN THE RFI PROCESS

Additional Resources

Overview

The Encompass production cost model will not necessarily replace the Tolk Units with like-in-kind generation. Instead, the model will optimally create an ‘expansion plan’ for each scenario based on the resource need, for example, replacing the Tolk Units could consist of a combination of solar, wind, battery storage, combustion turbines etc. – all at different locations, with different in-service dates.

While the expansion plan must meet SPS’s planning reserve margin, the model may also select additional resources to provide economical energy (i.e even when there is no resource need)

- Economically selected resources are not necessarily economical in all-years, nor are they necessarily lower cost than existing resources
- Encompass’s logic does not include a benefit-to-cost ratio threshold – for example, Encompass could select a project that lowers the PVRR by a marginal amount, even if it requires a multi-year, multi-million-dollar commitment
- Encompass evaluates system-wide costs over a long-term planning horizon, not necessarily the immediate impact to SPS’s ratepayers

Replacement Resources

Overview

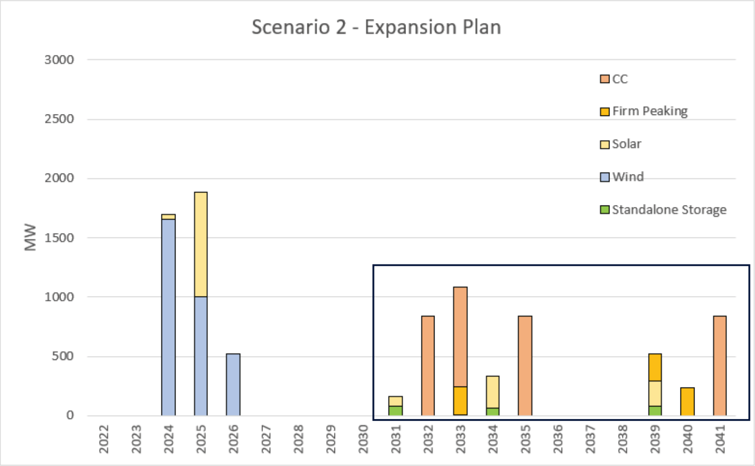
As the Encompass model must maintain SPS’s planning reserve margin, the early retirement of over 1GW of generation could be expected to produce a substantially different optimized expansion plan than the continued operation of Tolk Station (i.e there is a greater ‘need’ in one scenario)

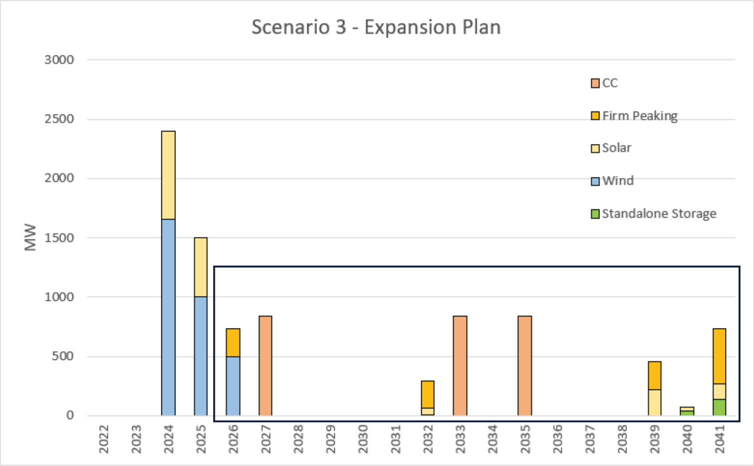
However, critical variables and external drivers fundamentally impact the optimized expansion plans for each scenario – this resulted in similar expansion plans between each retirement scenario

Scenario 2: Seasonal operations, 2032 retirement
Scenario 3: 2023 retirement

Expansion Plan

Sample Expansion Plan using Planning Load Forecast



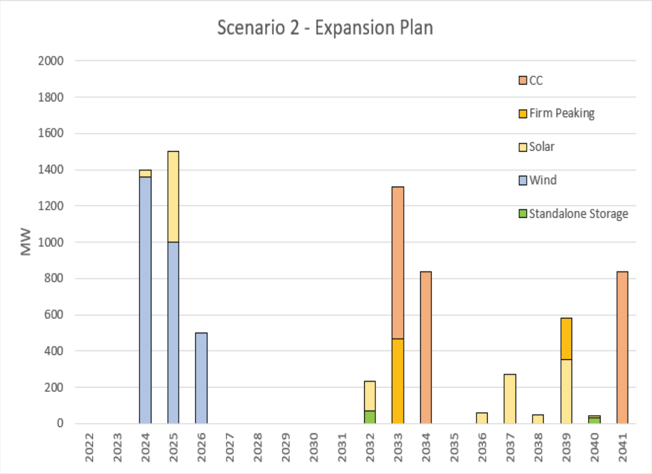


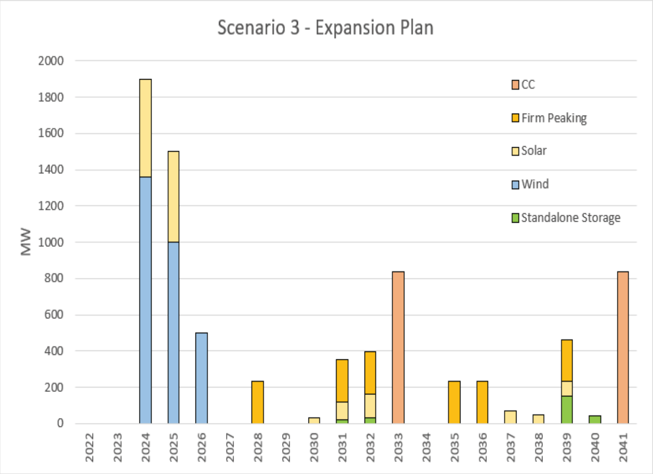
- Regardless of the retirement of the Tolk Units both Scenarios aggressively acquired the same amount of wind, and large quantities of solar generation between 2023 and 2025
- Renewable resources initially met the capacity need if the Tolk Units were retired early, however, as this capacity need grew the model added firm generation (as discussed on slide 16)

Scenario 2: Seasonal operations, 2032 retirement
Scenario 3: 2023 retirement

Expansion Plan

Sample Expansion Plan using Financial Load Forecast





- Lower load forecast provides similar results (Large-scale renewable build out, before firm generation resources are required

Expansion Plan

Critical Variables & External Drivers

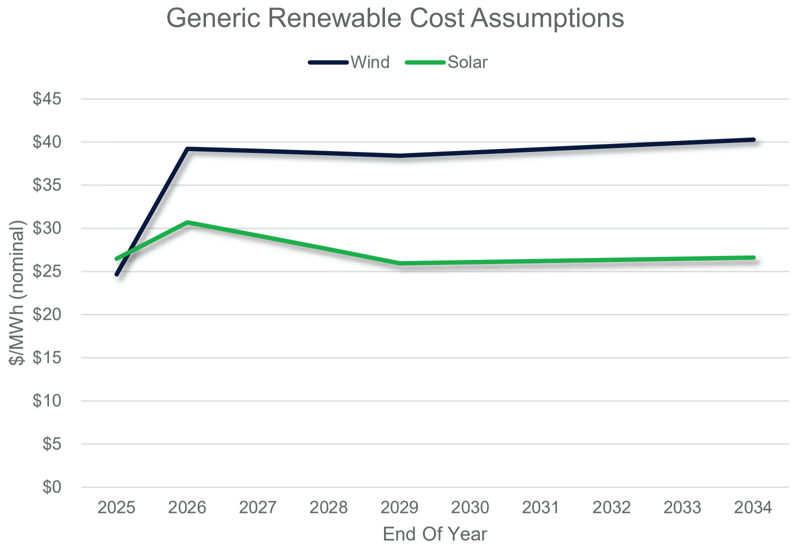
Questions: Why are the short-term expansion plans so similar between scenarios? Why does the model select such large quantities of renewables between EOY 2023 and EOY 2025?

Answer: Critical variables and external drivers fundamentally impact the expansion plan. They include:

1. Expiring Renewable Tax Credits
2. RFI proposals vs Generic Costs
3. Future cost of Generic Resources
4. Uncertainty in generator interconnection costs

Expiring Renewable Tax Credits

Impact to Replacement Generation



‘Generic’ Wind

- Increases from $24.65/MWh to $39.20/MWh after 60% PTC expires
- Relatively flat thereafter

‘Generic’ Solar

- Increases from $26.46/MWh to $30.68/MWh after 26% ITC steps down to 10%
- Pricing continues to decline until EOY 2029 – relatively flat thereafter

Prices stated exclude network upgrades costs

Expiring Renewable Tax Credits

Impact To Replacement Generation

Generic Wind

Driver: Without an extension of Production Tax Credits, wind generation will permanently, and substantially, increase in cost EOY2025

Result: Regardless of the retirement of Tolk Station, Encompass will add additional wind ‘today’, as it will be more expensive in the future – even if the wind generation operates ‘at-a-loss’ for several years

Generic Solar

Driver: Declining solar prices through EOY 2029 offset step-down of ITC

Result: Without a capacity need, Encompass will add economic solar ‘today’, but could acquire economically competitive solar in the future as costs continue to fall

RFI Proposals vs Generic Costs

Impact To Replacement Generation

- SPS used the approximate average cost of proposals received in the RFI process to baseline generic resource cost assumptions after 2025
- By default, multiple RFI proposals are lower cost than the generic resources available for selection in future years
- All-else-being-equal, expansion plans will favor selection of RFI proposals that are lower cost than the generic resources

Future cost of Generic Resources

Impact To Replacement Generation

- The Tolk Analysis incorporates conservative assumptions about the future costs of renewable generation – particularly wind generation (i.e generic wind gets more expensive after PTCs expire and technological / cost improvements do little to reduce future costs)
- The Encompass model may delay the acquisition of renewable resources if more lower future costs were anticpated

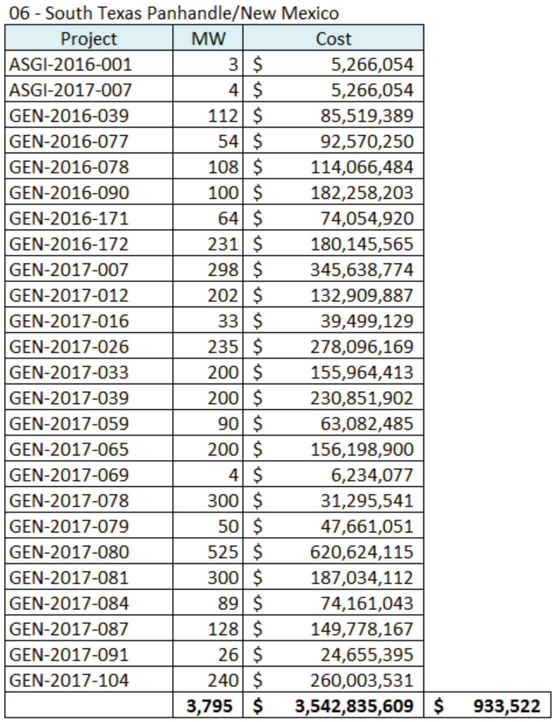
Generator Interconnection Costs

Impact to Replacement Generation

- Generic Overnight Construction Costs (excluding network upgrades):
  - Wind: ~$1,500/kW
  - Solar: ~$1,000/kW
- Developers ‘typically’ include up to $100k/W for network upgrades
- Multiple proposals received in the RFI did not include network upgrade costs
- DISIS 2017-01 PH1 study assigned average network upgrade costs of $933/kW

Generator Interconnection Costs

2017-01 DISIS Study



06 - South Texas Panhandle/New Mexico

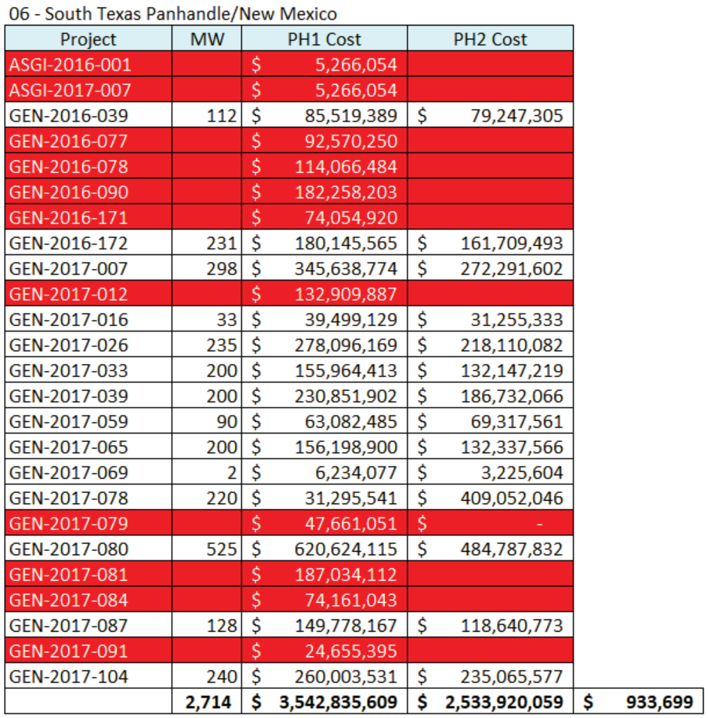
Project	MW	Cost	
ASGI-2016-001	3	$ 5,266,054	
ASGI-2017-007	4	$ 5,266,054	
GEN-2016-039	112	$ 85,519,389	
GEN-2016-077	54	$ 92,570,250	
GEN-2016-078	108	$ 114,066,484	
GEN-2016-090	100	$ 182,258,203	
GEN-2016-171	64	$ 74,054,920	
GEN-2016-172	231	$ 180,145,565	
GEN-2017-007	298	$ 345,638,774	
GEN-2017-012	202	$ 132,909,887	
GEN-2017-016	33	$ 39,499,129	
GEN-2017-026	235	$ 278,096,169	
GEN-2017-033	200	$ 155,964,413	
GEN-2017-039	200	$ 230,851,902	
GEN-2017-059	90	$ 63,082,485	
GEN-2017-065	200	$ 156,198,900	
GEN-2017-069	4	$ 6,234,077	
GEN-2017-078	300	$ 31,295,541	
GEN-2017-079	50	$ 47,661,051	
GEN-2017-080	525	$ 620,624,115	
GEN-2017-081	300	$ 187,034,112	
GEN-2017-084	89	$ 74,161,043	
GEN-2017-087	128	$ 149,778,167	
GEN-2017-091	26	$ 24,655,395	
GEN-2017-104	240	$ 260,003,531	
	3,795	**$ 3,542,835,609**	**$ 933,522**

1st Phase Study

- 25 projects totaling 3,795MW
- $3.5 Billion of network upgrades assigned
- Average $933,522 / MW

Generator Interconnection Costs

2017-01 DISIS Study



06 - South Texas Panhandle/New Mexico

Project	MW	PH1 Cost	PH2 Cost	
ASGI-2016-001		$ 5,266,054		
ASGI-2017-007		$ 5,266,054		
GEN-2016-039	112	$ 85,519,389	$ 79,247,305	
GEN-2016-077		$ 92,570,250		
GEN-2016-078		$ 114,066,484		
GEN-2016-090		$ 182,258,203		
GEN-2016-171		$ 74,054,920		
GEN-2016-172	231	$ 180,145,565	$ 161,709,493	
GEN-2017-007	298	$ 345,638,774	$ 272,291,602	
GEN-2017-012		$ 132,909,887		
GEN-2017-016	33	$ 39,499,129	$ 31,255,333	
GEN-2017-026	235	$ 278,096,169	$ 218,110,082	
GEN-2017-033	200	$ 155,964,413	$ 132,147,219	
GEN-2017-039	200	$ 230,851,902	$ 186,732,066	
GEN-2017-059	90	$ 63,082,485	$ 69,317,561	
GEN-2017-065	200	$ 156,198,900	$ 132,337,566	
GEN-2017-069	2	$ 6,234,077	$ 3,225,604	
GEN-2017-078	220	$ 31,295,541	$ 409,052,046	
GEN-2017-079		$ 47,661,051	$ -	
GEN-2017-080	525	$ 620,624,115	$ 484,787,832	
GEN-2017-081		$ 187,034,112		
GEN-2017-084		$ 74,161,043		
GEN-2017-087	128	$ 149,778,167	$ 118,640,773	
GEN-2017-091		$ 24,655,395		
GEN-2017-104	240	$ 260,003,531	$ 235,065,577	
	2,714	**$ 3,542,835,609**	**$ 2,533,920,059**	**$ 933,699**

2nd Phase

- 11 projects totaling 1,000MW dropped out
- $2.5 Billion of network upgrades still assigned
- Average $933,648/ MW
- 20% of network upgrades costs due by Mid-May

Generator Interconnection Costs

Impact to Replacement Generation

- SPS assigned various indicative network upgrade costs to all proposals that do not require a new GIA*
- Network upgrade costs assigned: $200/kW, $400/kW and $600/kW
- The same costs were applied to all wind, solar and combined cycle resources in **all future** years (assumed there is no benefit in waiting to acquire resources)
- The greater the network upgrades assigned; the more expansion plans will favor proposals with fully costed or executed GIAs

**Proposals not assigned network upgrade costs: (1) Proposals with existing GIA's, (2) BOT proposals at existing SPS generator locations (surplus interconnection / generator replacement)*

Replacement Resources

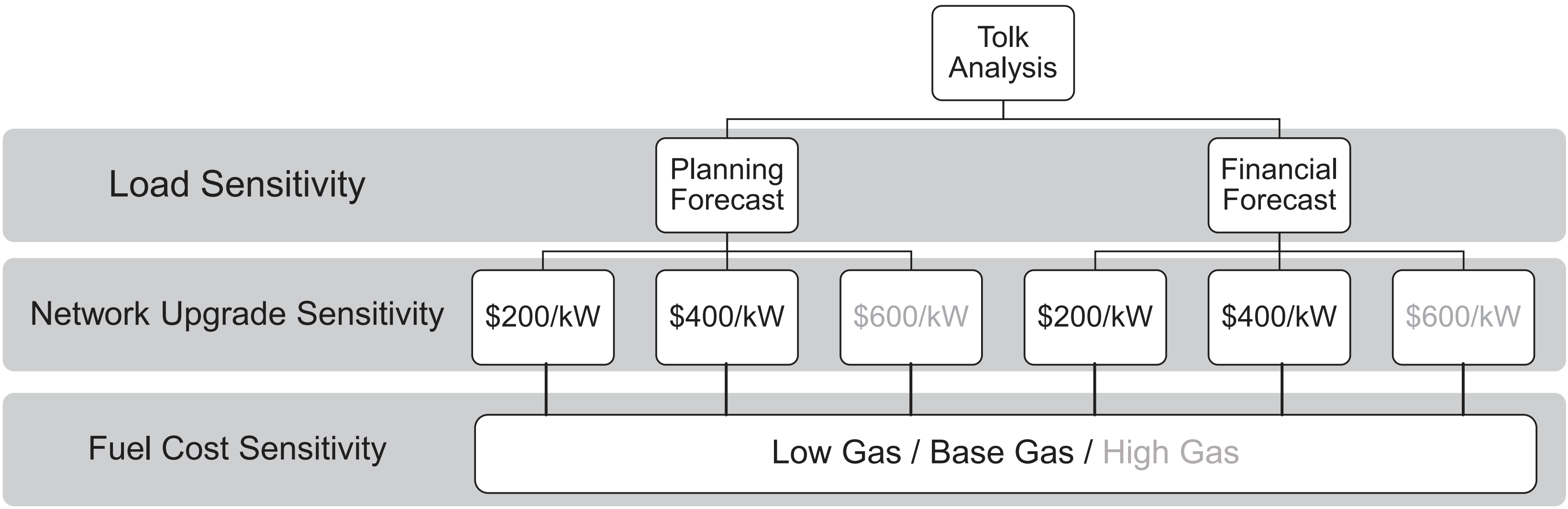
Conclusion

- Drivers and variables, such as expiring PTCs/ITCs, generic costs assumptions (both present and future) and the cost of network upgrades (both present and future), fundamentally impact when the expansion plans for each scenario
- This often results in the earlier selection of additional resource in the model
- While it is unlikely all these assumptions are correct, the Tolk Analysis is primarily a retirement analysis – not a thorough resource acquisition analysis
- As such, allowing the model to acquire potentially infeasible amounts of new generation on a possibly unrealistic timeline, allows SPS to stress-test the economic of continued operation of the Tolk Units

CONCLUSION 2 – PRELIMINARY RESULTS

Tolk Analysis Overview

Sensitivities



Tolk Analysis

Load Sensitivity

Planning Forecast

Financial Forecast

Network Upgrade Sensitivity

$200/kW

$400/kW

$600/kW

$200/kW

$400/kW

$600/kW

Fuel Cost Sensitivity

Low Gas / Base Gas / High Gas

Tolk Analysis Overview

Scenarios

Maximize Energy Value

- **Scenario 1**
  - ➢ Operate the Tolk Units year-round
  - ➢ Retire Tolk units EOY2025

Preserve Capacity Value

- **Scenario 2**
  - ➢ Operate the Tolk Units seasonally
  - ➢ Retire Tolk units EOY2032

Early Retirement

- **Scenario 3**
  - ➢ Operate the Tolk Units year-round
  - ➢ Retire Tolk units EOY2023
- **Scenario 6**
  - ➢ Operate the Tolk & Harrington Units year-round
  - ➢ Retire all units EOY2023

Hybrid Approach

- **Scenario 4**
  - ➢ Operate the Tolk Units year-round
  - ➢ Retire Tolk unit 1 EOY2023
  - ➢ Retire Tolk unit 2 EOY2031
- **Scenario 5**
  - ➢ Operate the Tolk Units seasonally
  - ➢ Retire Tolk unit 1 EOY2023
  - ➢ Retire Tolk unit 2 EOY2032

Throughout todays presentation, Scenarios 2 & 3 will be used to demonstrate SPS's preliminary conclusions

Preliminary PVRR Analysis

Base Gas - $400/kW Network Upgrades

IRP Action Period:	*2022 - 2025*
Decision Period:	*2022 - 2032*
IRP Planning Period	*2022 - 2041*

Planning Forecast - Base Gas - $400/kW

		Action Period		Decision Period		Planning Period	
		Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 152	$ 3,533	$ 366	$ 7,957	$ 299	$ 12,593
Scenario 2	2032 Retirement	$ -	$ 3,381	$ -	$ 7,591	$ -	$ 12,294
Scenario 3	2023 Retirement	$ 88	$ 3,469	$ 203	$ 7,794	$ 152	$ 12,446
Scenario 4	Staggered Retirement	$ 42	$ 3,423	$ 110	$ 7,701	$ 41	$ 12,335
Scenario 5	Staggered Retirement	$ 35	$ 3,415	$ 52	$ 7,643	$ (9)	$ 12,285
Scenario 6	Tolk/Har 2023	$ 258	$ 3,639	$ 800	$ 8,391	$ 933	$ 13,227

Excludes potential revenue for selling existing Water rights – Estimated at $0 - $20M (if sold TODAY!)

Financial Forecast - Base Gas - $400/kW

		Action Period		Decision Period		Planning Period	
		Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 148	$ 3,252	$ 123	$ 6,819	$ 62	$ 10,629
Scenario 2	2032 Retirement	$ -	$ 3,104	$ -	$ 6,697	$ -	$ 10,567
Scenario 3	2023 Retirement	$ 85	$ 3,189	$ 49	$ 6,746	$ (7)	$ 10,560
Scenario 4	Staggered Retirement	$ 47	$ 3,151	$ 100	$ 6,797	$ 46	$ 10,613
Scenario 5	Staggered Retirement	$ 45	$ 3,149	$ 67	$ 6,764	$ (9)	$ 10,558
Scenario 6	Tolk/Har 2023	$ 250	$ 3,354	$ 700	$ 7,397	$ 798	$ 11,365

Preliminary PVRR Analysis

Base Gas - $200/kW Network Upgrades

IRP Action Period:	*2022 - 2025*
Decision Period:	*2022 - 2032*
IRP Planning Period	*2022 - 2041*

Planning Forecast - Base Gas - $200/kW							
		Action Period		Decision Period		Planning Period	
		Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 76	$ 3,448	$ 92	$ 7,565	$ 133	$ 12,000
Scenario 2	2032 Retirement	$ -	$ 3,371	$ -	$ 7,473	$ -	$ 11,867
Scenario 3	2023 Retirement	$ 48	$ 3,420	$ 104	$ 7,577	$ 138	$ 12,006
Scenario 4	Staggered Retirement	$ (27)	$ 3,344	$ 5	$ 7,478	$ 22	$ 11,889
Scenario 5	Staggered Retirement	$ 6	$ 3,378	$ 19	$ 7,492	$ 9	$ 11,877
Scenario 6	Tolk/Har 2023	$ 202	$ 3,573	$ 579	$ 8,052	$ 945	$ 12,812

Excludes potential revenue for selling existing Water rights – Estimated at $0 - $20M (if sold TODAY!)

Financial Forecast - Base Gas - $200/kW							
		Action Period		Decision Period		Planning Period	
		Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 92	$ 3,182	$ (5)	$ 6,704	$ 53	$ 10,360
Scenario 2	2032 Retirement	$ -	$ 3,090	$ -	$ 6,709	$ -	$ 10,307
Scenario 3	2023 Retirement	$ 53	$ 3,143	$ (19)	$ 6,690	$ (10)	$ 10,297
Scenario 4	Staggered Retirement	$ 4	$ 3,094	$ (38)	$ 6,671	$ (28)	$ 10,279
Scenario 5	Staggered Retirement	$ 2	$ 3,092	$ (43)	$ 6,665	$ (42)	$ 10,265
Scenario 6	Tolk/Har 2023	$ 229	$ 3,319	$ 649	$ 7,358	$ 884	$ 11,191

Preliminary PVRR Analysis

Financial Forecast - Base Gas vs Low Gas - $400/kW Network Upgrades

IRP Action Period: *2022 - 2025*

Decision Period: *2022 - 2032*

IRP Planning Period *2022 - 2041*

Financial Forecast - Base Gas - $400/kW

		Action Period		Decision Period		Planning Period	
		Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 148	$ 3,252	$ 123	$ 6,819	$ 62	$ 10,629
Scenario 2	2032 Retirement	$ -	$ 3,104	$ -	$ 6,697	$ -	$ 10,567
Scenario 3	2023 Retirement	$ 85	$ 3,189	$ 49	$ 6,746	$ (7)	$ 10,560
Scenario 4	Staggered Retirement	$ 47	$ 3,151	$ 100	$ 6,797	$ 46	$ 10,613
Scenario 5	Staggered Retirement	$ 45	$ 3,149	$ 67	$ 6,764	$ (9)	$ 10,558
Scenario 6	Tolk/Har 2023	$ 250	$ 3,354	$ 700	$ 7,397	$ 798	$ 11,365

Excludes potential revenue for selling existing Water rights – Estimated at $0 - $20M (if sold TODAY!)

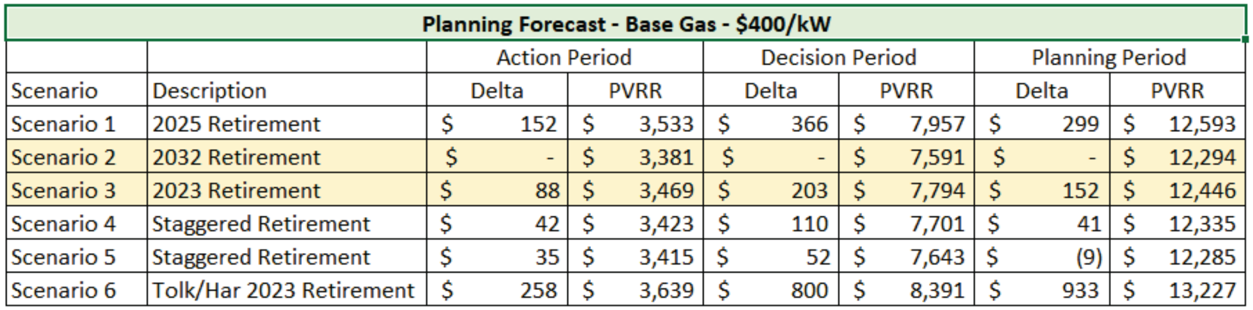
Financial Forecast - Low Gas - $400/kW

		Action Period		Decision Period		Planning Period	
		Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 176	$ 3,235	$ 215	$ 6,859	$ 146	$ 10,515
Scenario 2	2032 Retirement	$ -	$ 3,059	$ -	$ 6,644	$ -	$ 10,369
Scenario 3	2023 Retirement	$ 103	$ 3,162	$ 94	$ 6,739	$ 24	$ 10,393
Scenario 4	Staggered Retirement	$ 61	$ 3,120	$ 105	$ 6,749	$ 53	$ 10,422
Scenario 5	Staggered Retirement	$ 60	$ 3,119	$ 67	$ 6,711	$ 15	$ 10,383
Scenario 6	Tolk/Har 2023	$ 245	$ 3,305	$ 733	$ 7,377	$ 978	$ 11,346

SAMPLE EXPANDED VIEW – PLANNING FORECAST

PVRR Analysis

Planning Load Forecast including $400/kW network upgrades



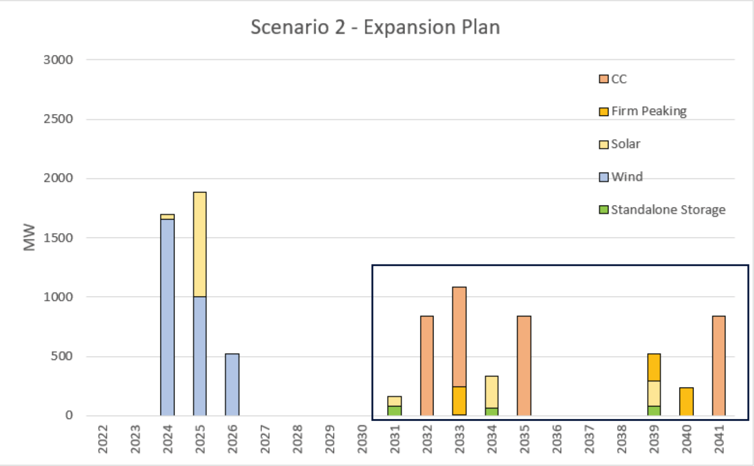
Planning Forecast - Base Gas - $400/kW							
		Action Period		Decision Period		Planning Period	
Scenario	Description	Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 152	$ 3,533	$ 366	$ 7,957	$ 299	$ 12,593
Scenario 2	2032 Retirement	$ -	$ 3,381	$ -	$ 7,591	$ -	$ 12,294
Scenario 3	2023 Retirement	$ 88	$ 3,469	$ 203	$ 7,794	$ 152	$ 12,446
Scenario 4	Staggered Retirement	$ 42	$ 3,423	$ 110	$ 7,701	$ 41	$ 12,335
Scenario 5	Staggered Retirement	$ 35	$ 3,415	$ 52	$ 7,643	$ (9)	$ 12,285
Scenario 6	Tolk/Har 2023 Retirement	$ 258	$ 3,639	$ 800	$ 8,391	$ 933	$ 13,227

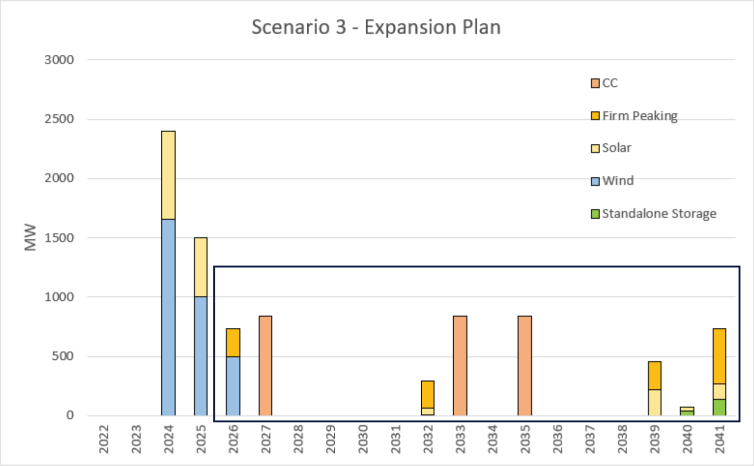
- Scenario 2 (seasonal operation 2032) vs Scenario 3 (2023 retirement) Comparison
  - ➢ Over the 4-year action period Scenario 3 is $88M higher cost than Scenario 2 (PVRR)
  - ➢ Between 2022 and EOY 2032, Scenario 3 is $203M higher cost than Scenario 2 (PVRR)
  - ➢ Over the 20-year planning period, Scenario 3 is $152M higher cost than Scenario 2 (PVRR)

Scenario 2: Seasonal operations, 2032 retirement
Scenario 3: 2023 retirement

Expansion Plan

Sample Expansion Plan using Planning Load Forecast



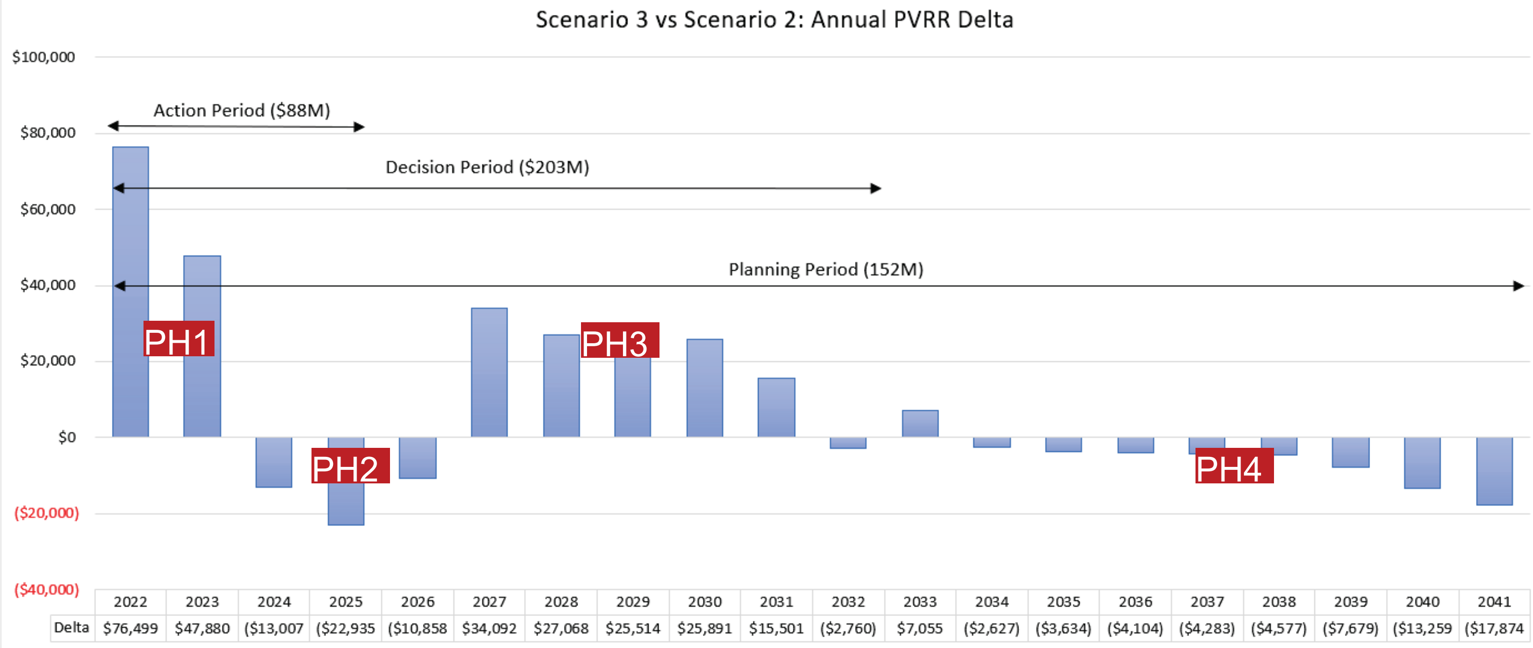


- Regardless of the retirement of the Tolk Units both Scenarios aggressively acquired the same amount of wind, and large quantities of solar generation between 2023 and 2025
- Renewable resources initially met the capacity need if the Tolk Units were retired early, however, as this capacity need grew the model added firm generation (as discussed on slide 16)

Scenario 2: Seasonal operations, 2032 retirement
Scenario 3: 2023 retirement

PVRR Analysis

Scenario 3 vs Scenario 2 – PVRR Annual Comparison

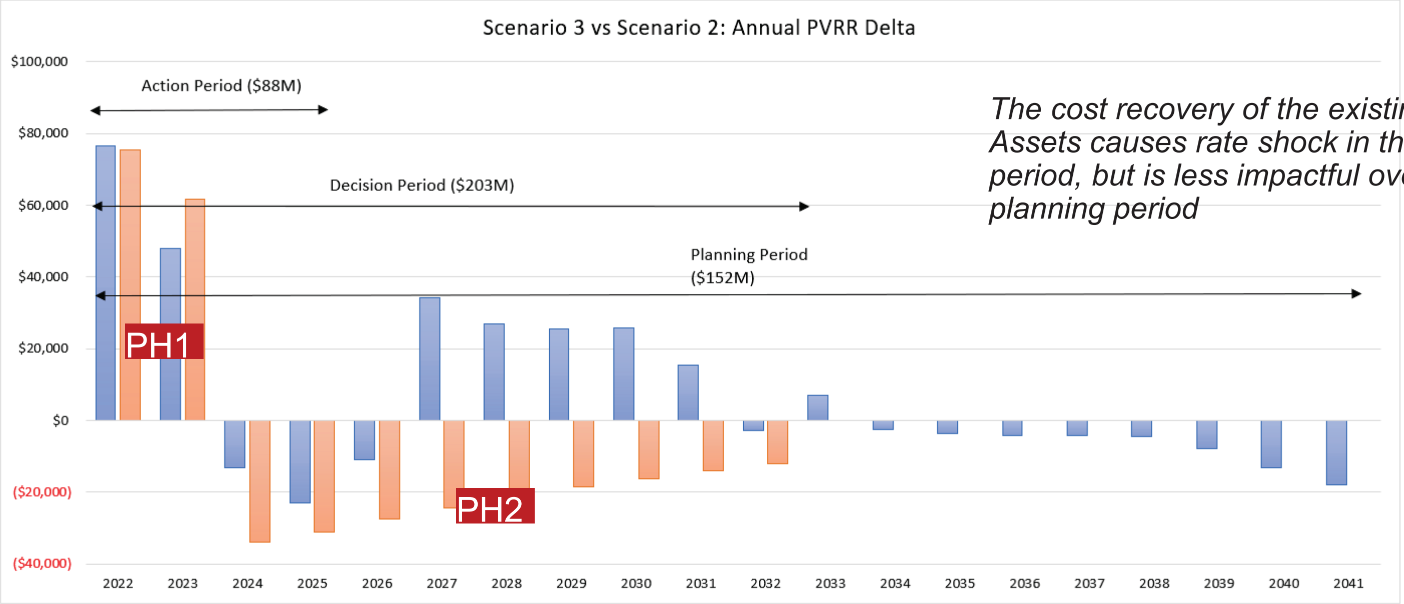


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Delta	$76,499	$47,880	($13,007	($22,935	($10,858	$34,092	$27,068	$25,514	$25,891	$15,501	($2,760)	$7,055	($2,627)	($3,634)	($4,104)	($4,283)	($4,577)	($7,679)	($13,259	($17,874

- *Ph1: Cost recovery of Tolk assets (Sc3), Ph2: Cost recovery of Tolk assets (Sc2) / Similar expansion plans capable of fulfilling capacity need, Ph3: Deferred generation (Sc2), Ph4: Additional generation (Sc2)*

PVRR Analysis – Cost Recovery of Tolk Asset

Scenario 3 vs Scenario 2



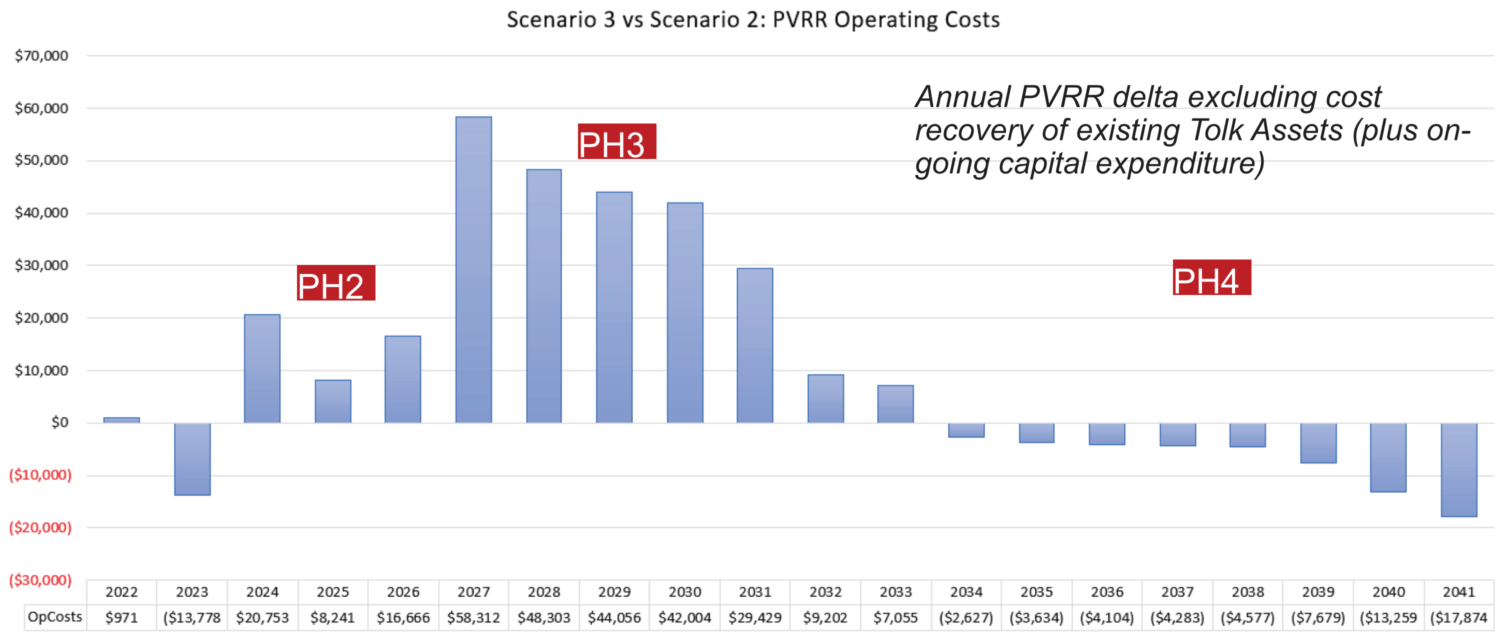
The cost recovery of the existing Tolk Assets causes rate shock in the action period, but is less impactful over the planning period

Blue: Annual PVRR Deltas (same as previous slide), Orange: Cost Recovery of Tolk Assets

Ph1: Cost recovery of Tolk assets (Sc3), Ph2: Continued cost recovery of Tolk assets (Sc2)

PVRR Analysis – Operating Costs

Scenario 3 vs Scenario 2



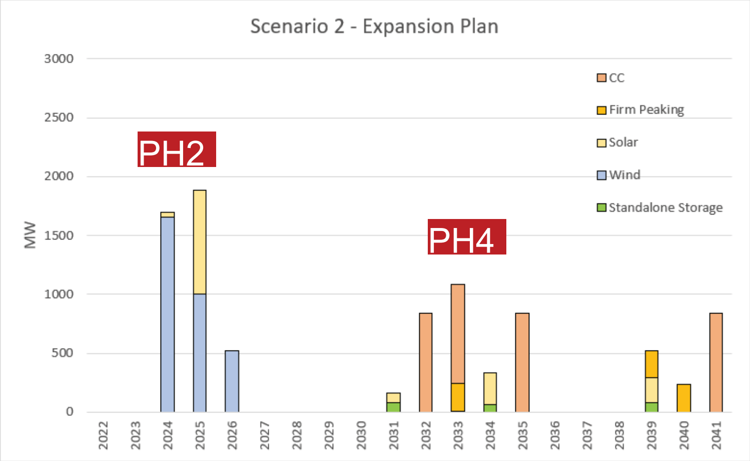
Annual PVRR delta excluding cost recovery of existing Tolk Assets (plus on-going capital expenditure)

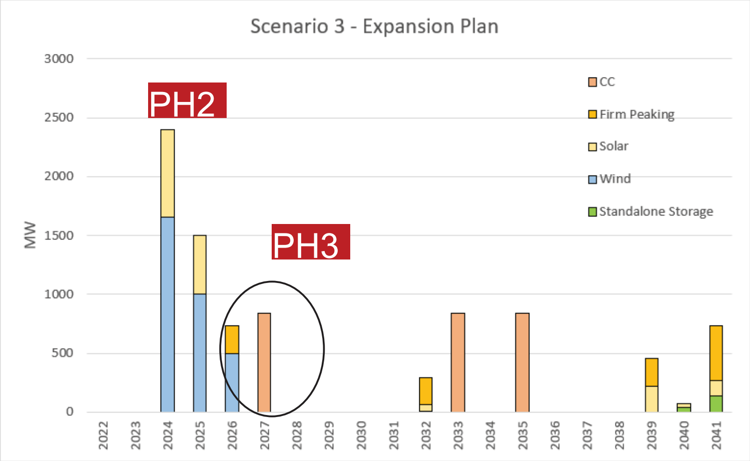
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
OpCosts	$971	($13,778	$20,753	$8,241	$16,666	$58,312	$48,303	$44,056	$42,004	$29,429	$9,202	$7,055	($2,627)	($3,634)	($4,104)	($4,283)	($4,577)	($7,679)	($13,259	($17,874

Ph2: Similar expansion plans capable of fulfilling capacity need, Ph3: Deferred generation (Sc2), Ph4: Additional generation (Sc2)

PVRR Analysis – Operating Costs

Scenario 3 vs Scenario 2


Scenario 2 - Expansion Plan


Scenario 3 - Expansion Plan

Ph2: Similar expansion plans capable of fulfilling capacity need, Ph3: Deferred generation (Sc2), Ph4: Additional generation (Sc2)

Xcel Energy®

SAMPLE EXPANDED VIEW FINANCIAL LOAD FORECAST

Preliminary PVRR Analysis

Financial Load Forecast including $400/kW network upgrades

IRP Action Period: *2022 - 2025*
Decision Period: *2022 - 2032*
IRP Planning Period *2022 - 2041*

Financial Forecast - Base Gas - $400/kW

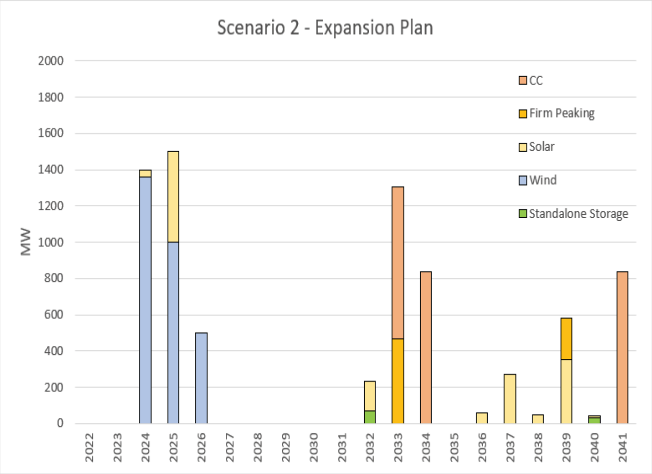
		Action Period		Decision Period		Planning Period	
	Description	Delta	PVRR	Delta	PVRR	Delta	PVRR
Scenario 1	2025 Retirement	$ 148	$ 3,252	$ 123	$ 6,819	$ 62	$ 10,629
Scenario 2	2032 Retirement	$ -	$ 3,104	$ -	$ 6,697	$ -	$ 10,567
Scenario 3	2023 Retirement	$ 85	$ 3,189	$ 49	$ 6,746	$ (7)	$ 10,560
Scenario 4	Staggered Retirement	$ 47	$ 3,151	$ 100	$ 6,797	$ 46	$ 10,613
Scenario 5	Staggered Retirement	$ 45	$ 3,149	$ 67	$ 6,764	$ (9)	$ 10,558
Scenario 6	Tolk/Har 2023 Retirement	$ 250	$ 3,354	$ 700	$ 7,397	$ 798	$ 11,365

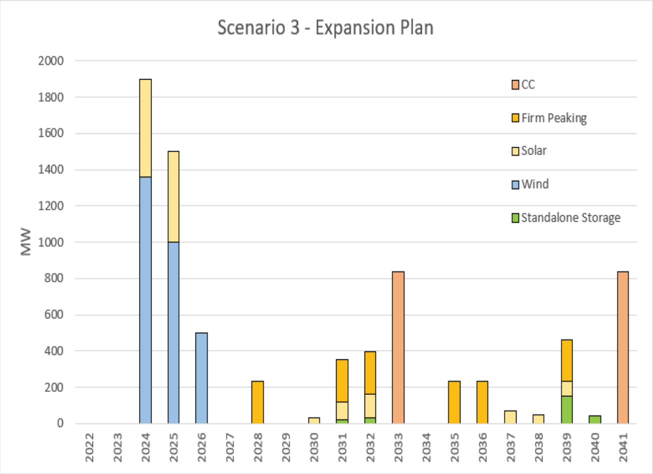
- Scenario 2 (continued operations) vs Scenario 3 (2023 retirement) Comparison
  - ➢ Over the 4-year action period Scenario 3 is $85M higher cost than Scenario 2 (PVRR)
  - ➢ Between 2022 and EOY 2032, Scenario 3 is $49M higher cost than Scenario 2 (PVRR)
  - ➢ Over the 20-year planning period, Scenario 3 is $7M lower cost than Scenario 2 (PVRR)

Scenario 2: Seasonal operations, 2032 retirement
Scenario 3: 2023 retirement

Expansion Plan

Sample Expansion Plan using Financial Load Forecast



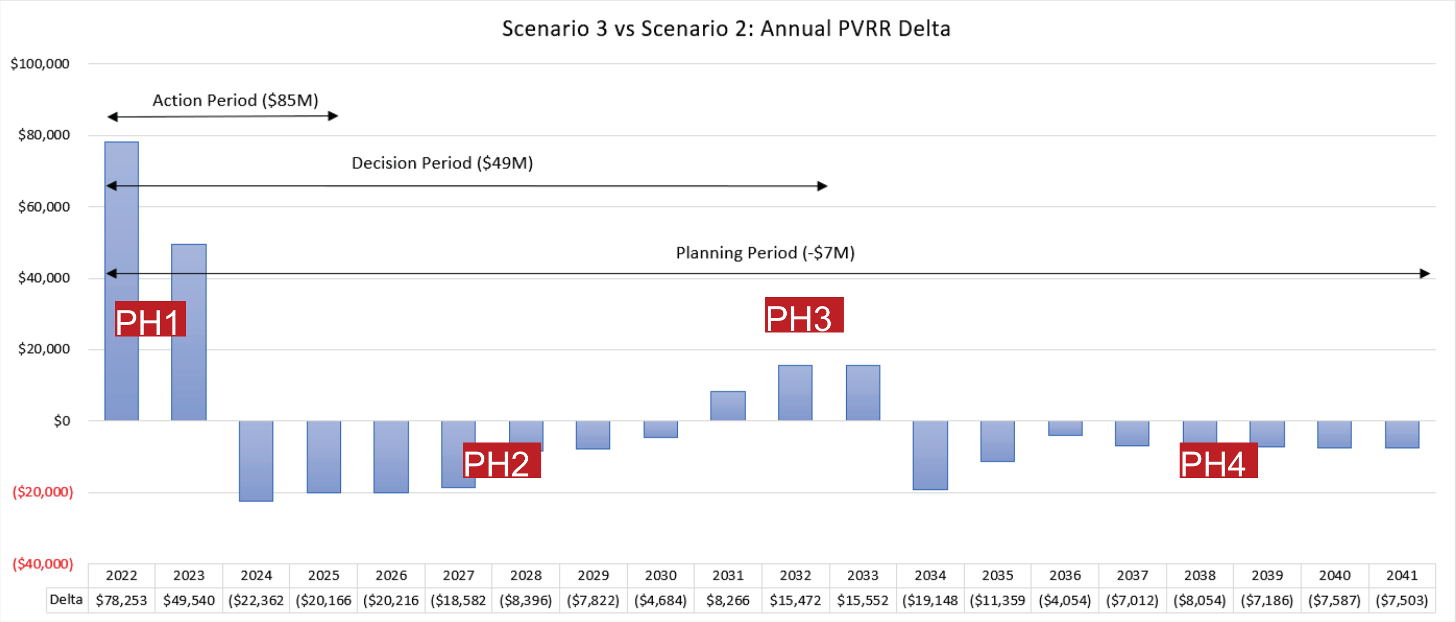


- Lower load forecast provides similar results (Large-scale renewable build out, before firm generation resources are required

Scenario 2: Seasonal operations, 2032 retirement
Scenario 3: 2023 retirement

PVRR Analysis

Scenario 3 vs Scenario 2 – PVRR Annual Comparison

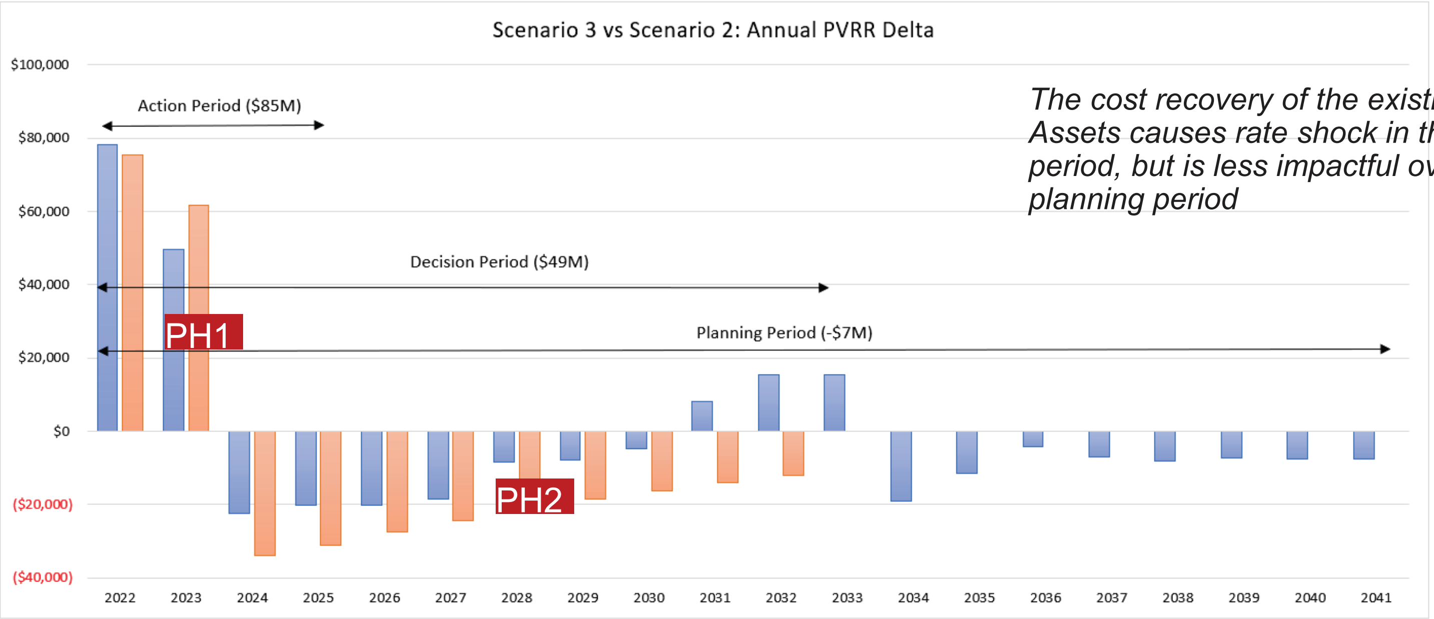


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Delta	$78,253	$49,540	($22,362	($20,166	($20,216	($18,582	($8,396)	($7,822)	($4,684)	$8,266	$15,472	$15,552	($19,148	($11,359	($4,054)	($7,012)	($8,054)	($7,186)	($7,587)	($7,503)

- *Ph1: Cost recovery of Tolk assets (Sc3), Ph2: Cost recovery of Tolk assets (Sc2) / Similar expansion plans capable of fulfilling capacity need, Ph3: Deferred generation (Sc2), Ph4: Additional generation (Sc2)*

PVRR Analysis – Cost Recovery of Tolk Asset

Scenario 3 vs Scenario 2



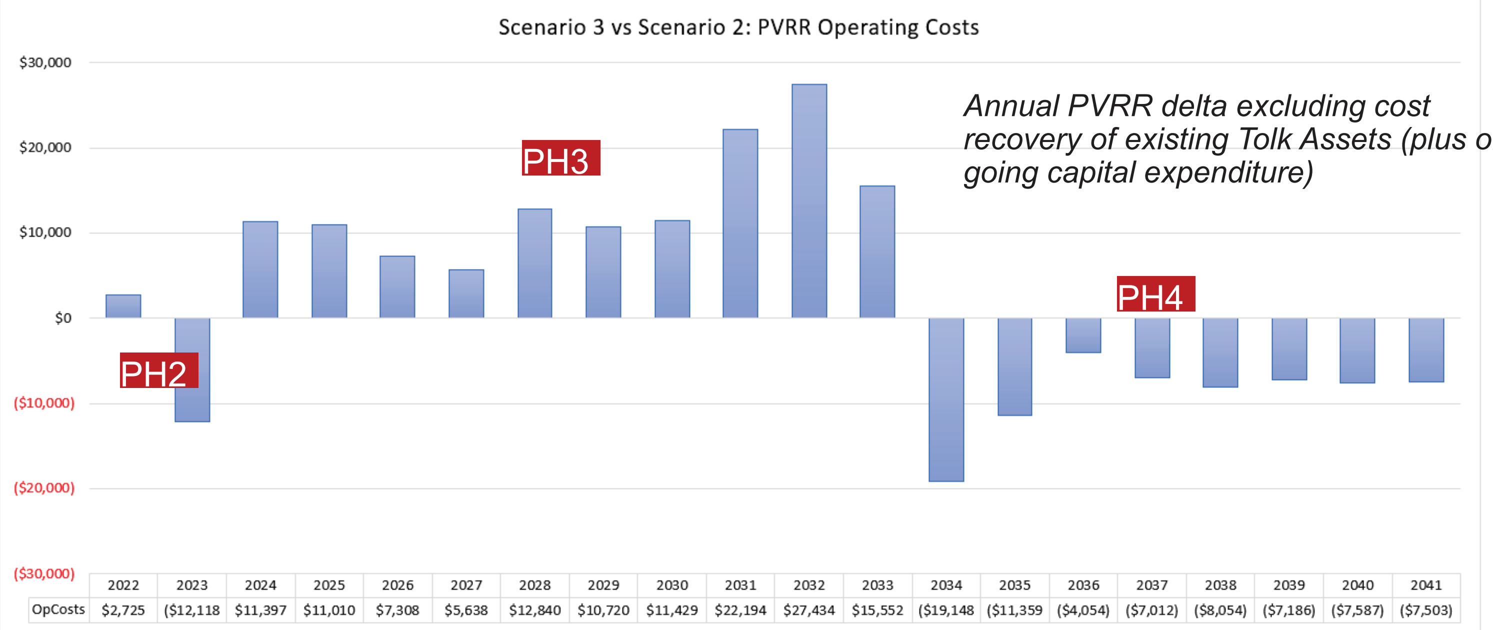
The cost recovery of the existing Tolk Assets causes rate shock in the action period, but is less impactful over the planning period

Blue: Annual PVRR Deltas (same as previous slide), Orange: Cost Recovery of Tolk Assets

Ph1: Cost recovery of Tolk assets (Sc3), Ph2: Continued cost recovery of Tolk assets (Sc2)

PVRR Analysis – Operating Costs

Scenario 3 vs Scenario 2



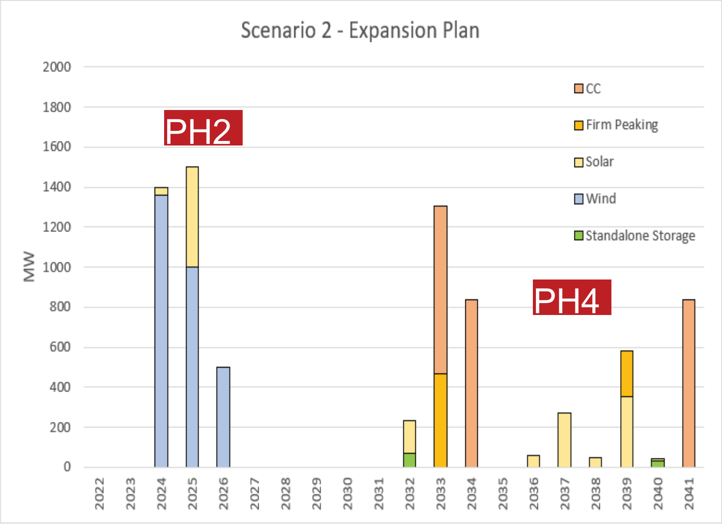
Annual PVRR delta excluding cost recovery of existing Tolk Assets (plus on-going capital expenditure)

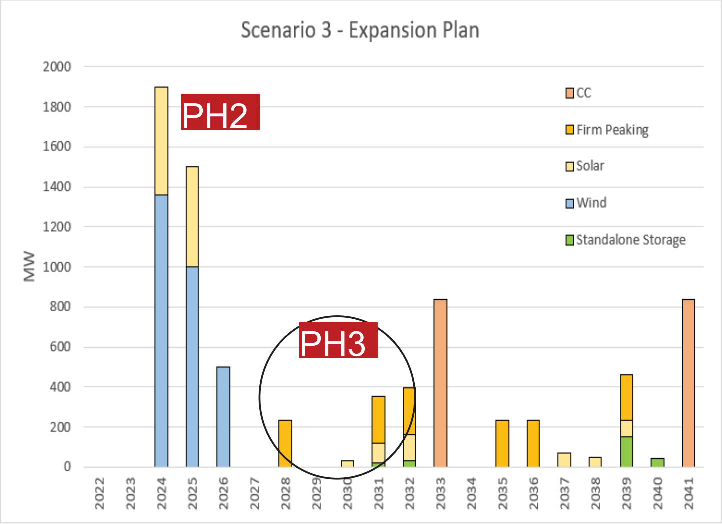
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
OpCosts	$2,725	($12,118	$11,397	$11,010	$7,308	$5,638	$12,840	$10,720	$11,429	$22,194	$27,434	$15,552	($19,148	($11,359	($4,054)	($7,012)	($8,054)	($7,186)	($7,587)	($7,503)

Ph2: Similar expansion plans capable of fulfilling capacity need, Ph3: Deferred generation (Sc2), Ph4: Additional generation (Sc2)

PVRR Analysis – Operating Costs

Scenario 3 vs Scenario 2





Ph2: Similar expansion plans capable of fulfilling capacity need, Ph3: Deferred generation (Sc2), Ph4: Additional generation (Sc2)

FINAL REVIEW

Final Review

Conclusion 1

- The acquisition of economic energy is not dependent on the retirement of the Tolk units
- Regardless of the operation and retirement dates of the Tolk units, the Tolk Analysis indicates there could be opportunities for SPS to acquire economic energy
- Large uncertainty with key drivers, such as the potential extension of renewable tax credits and the cost of interconnecting new generation

Final Review

Conclusion 2

- Retirement of the Tolk Units creates an immediate resource need
- The acquisition of potentially economic renewable energy could theoretically fulfill a short-term capacity shortage
- However, load growth and/or plant retirements will require SPS to add firm resources and/or battery storage to meet load and capacity obligations
- The capacity cost of the Tolk units is relatively low cost when compared to the acquiring new generating resources (CT’s, CC’s or energy storage)
- The Tolk Analysis continues to support seasonal operations of the Tolk Units and a 2032 retirement
- The Tolk Analysis does not capture all benefits of the Tolk Units, as demonstrated during Winter Storm Uri

Xcel Energy®

Scope of Work
Independent Evaluator

Executive Summary

Southwestern Public Service Company ("SPS") is planning to issue an all-source Request for Information ("RFI") to obtain current pricing, technical characteristics, and other relevant information for potential generating resources. The results from the RFI will be incorporated into an evaluation of the potential abandonment and replacement of SPS's Tolk Station, herein known as "the Tolk Analysis," which will include an analysis in which all coal-burning units are retired or replaced before 2030 as set forth in the recent New Mexico Public Regulation Commission final order adopting the stipulation in SPS's most recent rate case.[1] SPS is seeking the services of an Independent Evaluator ("IE") to provide an independent review of the RFI process and Tolk Analysis to evaluate the fairness of SPS's bid solicitation and bid evaluation processes. Upon completion of the RFI solicitation and SPS's development of the Tolk Analysis, the IE will report its findings to the New Mexico Public Regulation Commission ("NMPRC") and SPS.

The primary objectives of the IE's independent review will be to:

- Assess whether that the RFI parameters are consistent with the objectives of the Tolk Analysis
- Assess whether the RFI documents including Standard Bidders Forms provide sufficient and consistent information for respondents to the RFI ("Bidders") to prepare proposals
- Identify any undue bias in the criteria used or as applied to evaluate bids
- Assess whether a consistent and fair methodology was used to screen and rank bids
- Assess whether the bids were fairly incorporated into the Tolk Analysis
- Provide an assessment of the Tolk Analysis including any deficiencies in the parameters or results of the analysis

Background

Tolk Station consists of two coal-powered steam turbine units, located in Lamb County, Texas. Each unit has a net capacity of approximately 540 MW, for a total net capacity of approximately 1,080 MW.

Tolk Station relies exclusively on groundwater from the Ogallala Aquifer for generation cooling, and the Ogallala Aquifer is in an irreversible decline. To conserve water, and the life of Tolk Station, SPS has implemented a plan to reduce the number of hours the Tolk units operate annually.

SPS is required to analyze a range of operating parameters and retirement dates for Tolk Station. The analysis will incorporate the pricing and technical characteristics obtained in the RFI process. The results of the analysis will be included in SPS's next Integrated Resource Plan ("IRP"), to be filed in July 2021.

---

[1] Uncontested Comprehensive Stipulation ("Stipulation") filed at the New Mexico Public Regulation Commission on January 13, 2020 and approved by the New Mexico Public Regulation Commission ("NMPRC") in Case No. 19-00170-UT.

As part of the Tolk Analysis, SPS will use the information obtained from this RFI to include an evaluation of the potential retirement and replacement of all of SPS's coal burning generation.

Timeline

SPS is required to complete the Tolk Analysis by June 2021, one month before the IRP. To meet the filing date, SPS anticipates issuing the RFI in the Summer of 2020. Bidders will then be given 60 days to submit their proposals. The evaluation process and Tolk Analysis is expected to take approximately six months from receipt of bids.

IE Responsibilities

To achieve the primary objectives, the IE will be provided immediate and continuing access to all documents and data reviewed, used, or produced by SPS in the preparation of the Tolk Analysis and in its bid solicitation, evaluation, and selection processes. SPS will provide to the IE bid evaluation results and modeling runs so that the IE can verify these results and can investigate options that SPS did not consider.

To conduct a thorough, independent, and unbiased review of the RFI process and Tolk Analysis, the IE will perform the following activities:

Meetings

The IE will attend an initial kickoff meeting prior to issuance of the RFI either via teleconference or in person at SPS's offices in Amarillo, Texas. The kickoff meeting will provide an opportunity to discuss the RFI parameters, specific items which may be required for the Tolk Analysis, and SPS's thoughts, goals and objectives regarding the RFI and Tolk Analysis. SPS will establish and explain confidentiality protection procedures regarding bid information and evaluation. Additional details regarding project administration and public communications will be discussed at the kickoff meeting as well.

The IE will conduct regular project status calls with SPS to discuss the project and identify and mitigate any issues that arise.

The IE will attend via teleconference at all future public technical conferences and other meetings as necessary to achieve the primary objectives.

Review and Finalize RFI Documents and Evaluation Process

The IE will critically review the draft RFI and any associated documents and notification communications with the objective of determining whether there are any undue biases presented to any category of potential Bidders as a result of the structure of the RFI requirements and make recommendations as needed. Additionally, the IE will review and evaluate the draft proposal submittal requirements and standard bidder forms and make recommendations as needed.

The IE understands that some recommendations may not be agreeable to SPS or possible for SPS to implement. If SPS chooses not to follow the IE's recommendations, SPS will provide a brief, written response to the IE explaining the choices made. SPS may or may not decide to follow the recommendations and guidance provided by the IE and these decisions will be documented as part of the Independent Evaluator Report ("IE Report").

Review Bidder Communications

Upon issuance of the RFI, the SPS staff directly involved with the RFI will adhere to strict communication protocols with Bidders. The IE will examine any communications between SPS and Bidders during the RFI review period, which will begin with the issuance of the RFI and end with filing of SPS's 2021 integrated resource plan in July 2021. The purpose of this examination will be to determine whether Bidders were treated fairly during the submittal and evaluation periods, and whether SPS was unduly biased toward a specific bid.

Evaluate the SPS Economic Modeling of Bids

The IE shall conduct a thorough and unbiased review of the due diligence activities performed by SPS for each prospective bid, as well as a review of the economic modeling of each bid to confirm the modeling was accurate and consistent across all bids.

In reviewing the due diligence activities, the IE will review each bid and associated Standard Bidding Forms, followed by a review of SPS's documented non-economic evaluation of all bids.

Evaluation of the Tolk Analysis

The IE shall conduct a thorough, and unbiased review of the Tolk Analysis parameters and results. The review should include, but not be limited to, consideration of potentially different retirement dates of the Tolk units, the feasibility of acquiring adequate replacement resources in the timeframe necessary, and availability of economic water in each of the scenarios modeled.

The IE will conduct a thorough review of key inputs and parameters to the Tolk Analysis including, but not limited, SPS's natural gas price forecasts and system load forecasts.

Prepare and Provide Independent Review Report

The IE will prepare an IE report of its findings and conclusions regarding the Tolk Analysis. Initial drafts of the report are anticipated to be reviewed internally by SPS and in collaboration with the IE for quality assurance. After incorporating any necessary revisions to the report that are identified as a result of the reviews, the IE will issue the final IE report redacted as necessary to ensure protection of confidential information; confidential information referenced should be made available only under appropriate protective order procedures.

BACKGROUND

As previously indicated, Xcel Energy maintains a list of pre-qualified bidders. SPS reached out to the parties in June to identify any potential additional bidders that could be solicited to be added to the pre-qualified list, but, did not identify any additional prospects outside of a consultant in the San Juan replacement proceeding and E3 (which had performed a study for EPE). E3 was already a pre-qualified bidder and was included in the request for proposals (RFP). SPS did not solicit the pre-qualification of the other consultant.

On July 6th, 2020, SPS issued an RFP to pre-qualified bidders for the services of an independent evaluator. SPS held a pre-meeting with the bidders on July 8th, 2020 to provide submittal instructions and answer questions from bidders. SPS received proposals from two bidders out of four pre-qualified parties, Guidehouse and Leidos, by the July 20th, 2020 deadline. The other two bidders were either unable to commit the resources necessary in the timeframe required or failed to submit a proposal.

On July 23rd, 2020, SPS held individual meetings with each bidder. Each bidder was then provided the opportunity to revise their proposals to ensure all proposals were aligned. Each bidder has extensive experience and expertise providing the services required to oversee a fair and robust analysis. Each bidder also proposed a highly experienced evaluation team, with many decades of relevant experience. After evaluating the proposals SPS was satisfied that either bidder could successfully fulfill the role of independent evaluator based on the submitted proposals. Each proposal included comparable billable rates. There is no material cost difference between each bidder.

RECOMMENDATION

SPS recommends proceeding with Guidehouse as the independent evaluator. It is a close decision as (1) both bidders offer a wealth of experience and expertise and (2) there is not a material difference in price. As such, SPS' recommendation is based on the overall content and quality of the submission, and specifically the follow-up discussions with each bidder. While SPS is confident Leidos could successfully fulfill the role of independent evaluator, Guidehouse's submission was marginally superior.

Guidehouse

Independent Evaluator Report of the Southwestern Public Service Company's Tolk Analysis and RFI

Submitted by:

Guidehouse Inc.
1800 Tysons Boulevard, 7th Floor
McLean, VA 22102-4257
(646) 227-4895
dkoujak@guidehouse.com

Reference No.: 214834
June 30, 2021

Table of Contents

1. Background

Guidehouse Inc. was selected as the independent evaluator (IE) to oversee the Southwestern Public Service Company (SPS) Tolk Analysis pursuant to the Uncontested Comprehensive Stipulation (the Stipulation) filed at the New Mexico Public Regulation Commission on January 13, 2020, and approved by the Commission in Case No. 19-00170-UT. Under the Stipulation, SPS is required to submit a robust analysis of both:

- Abandonment of its Tolk Generating Station Units 1 and 2
- Consideration of a scenario in which all SPS's coal-burning units are retired or replaced before 2030

The Tolk Station is a 1,067 MW generating station located in Lamb County, Texas. This station provides power to customers both in Texas and New Mexico. Retirement of the Tolk Station is being driven predominantly by water resource constraints and projected depletion in the vicinity of the plant. The Tolk Station currently operates to maintain reliability by provide needed generating capacity responsive to peak load conditions in the SPS service territory. Accordingly, in retiring the Tolk station, the load carrying capacity of the unit – which is the ability to dispatch up to 1,067 MW responding to customer demand, is the primary attribute that needs to be replaced through alternative resource options.

To inform SPS of the available alternative resource options that are available to replace Tolk, a request for information (RFI) process was initiated to provide SPS with information relating to availabilities, flexibilities, and preferences from the market participants in terms of providing capacity and associated energy from all available generating resource types. This information is key in determining whether there are feasible and economic opportunities to replace Tolk and all other coal-fired power plants. Contractual options to replace Tolk and other generating stations include build-own-transfers (BOTs) and power purchase agreements (PPAs), with pricing based on information obtained from the RFI process.

2. Scope of Review

Guidehouse's role as the IE was to effectively ensure the fairness, transparency, clarity, and prudence of the process undertaken to evaluate the options to replace the Tolk Generating Station. In this report, we review and discuss:

- Whether SPS conducted an evaluation of potential retirement dates.
- Whether SPS considered available replacement resources.
- Whether SPS used fair solicitation and evaluation processes.

To facilitate this review, SPS was stipulated to work cooperatively with Guidehouse as the IE and provide us access to all documents and information leveraged by the utility in the preparation of its plan and in its bid solicitation, evaluation, and selection processes. SPS also was required to provide the bid evaluation results and modeling runs so that we could verify the results and investigate options the utility did not consider.

In the following sections of this report, we outline our review of SPS's process to evaluate the options, starting with the RFI process.

3. RFI Process

SPS released the 2020 Request for Information for Generating Resources (the RFI) on September 9, 2020. Under the RFI, SPS solicited interest from existing or proposed generating facilities within or delivered to the SPS zone. The RFI was open to generating facilities providing capacity and associated energy to SPS from all generating resource types, including energy storage, whether existing or yet-to-be constructed. Proposals were allowed to provide pricing options under the following arrangements: build-own-transfers (BOTs) and power purchase agreements (PPAs).

3.1 Design

The design of the RFI was relatively straightforward. SPS established basic qualifications to participate in the RFI, as follows:

- Expressions of interest should be from existing or proposed generating facilities within the SPS zone or delivered to the SPS zone from existing or proposed sites within the Southwest Power Pool (SPP) territory.
- Expressions of interest should include a proposed commercial operation date (COD) if the submission is a future resource.
- Expressions of interest should include all capacity, energy, environmental attributes such as renewable energy credits, and other generation-related services.
- For purposes of this RFI, renewable energy refers to electrical power generated by solar, wind, biomass, or other commercially viable renewable energy technologies including energy storage.
- SPS is interested in the availability of capacity and associated energy resources for possible future-owned generation, BOTs, and PPAs.
- PPA durations should be 25 and 30 years.
- Interested parties should respond to the RFI within 60 days of issuance.

To participate in the RFI, bidders were requested to submit a completed Excel template containing the information necessary for SPS to model and evaluate supply options. The template requested information on the following:

- Company proposing the resource
- Bidder contact information
- General information on the project and its location
- Contract options proposed
- Pricing
- Interconnection details and cost information
- Performance and related technical specifications

In the RFI, SPS noted it would evaluate the following information:

- Project type, including technical characteristics.
- Project site location for delivery within (or to) the SPS system.
- Proposed COD for resource facilities responsive to this RFI; the impact a delay in the proposed COD would have on the pricing.
- Pricing and quantity in megawatts.
- Current interconnection status (if any) and anticipated extent of need for transmission system upgrades for the proposal.
- Impact of available tax credits on proposed projects.
- Proposals must demonstrate an anticipated ability to obtain all required state/local preconstruction approvals and any associated risks to meet the COD.

From our perspective, the primary objective of an RFI process is to solicit a response from market participants that responds to a specific need to the maximum extent possible. To achieve this result, an RFI should have:

- Eligibility requirements that are not unduly restrictive
- A relatively low burden to participate, limited only to information absolutely necessary for a utility to carry out its analysis

In the RFI's design, the eligibility to participate was open to both existing and future resources from all generating resource types. Forms provided to market participants were designed to elicit a response from thermal, renewable, and storage resources. Furthermore, the response forms, which encapsulate the entire information request, contain information that is required to conduct the analysis. We view the information request under the RFI to not carry a significant burden to market participants to propose a response.

3.2 Process

SPS posted the RFI and associated materials on its website, available at https://www.xcelenergy.com/working_with_us/tolk_request_for_information. To introduce the RFI and answer questions from potential respondents, a bidders meeting was held by SPS on September 21, 2020. During the meeting, bidders were given an opportunity to address questions directly to SPS. Questions were also received from bidders directly via e-mail to the RFI inbox. During the pendency of the RFI up to the bid submission due date of 4:00 p.m. Mountain Daylight Time on Friday, November 6, 2020, SPS received and posted responses to questions both on its website and directly to the inquiring bidder.

Proposals were initially reviewed for completeness. SPS issued several rounds of clarifying questions to secure the information necessary to evaluate the options needed. With our concurrence and at our behest, to the extent that bidders did not include optimal COD dates or configurations that would better address SPS's needs, SPS issued additional clarifications requesting such options.

Certain projects were excluded from further analysis. They included projects that were voluntarily withdrawn by the proponents and in addition to those that proscribed a timeline for selection within 2022 to be valid by the necessary COD dates. Exclusion of projects that require immediate contracting, where it is not feasible under the regulatorily established timeline, is appropriate and maintains fairness to all market participants. If SPS were to accelerate the timeline to accommodate a single project or set of projects, this would not be consistent with fairness.

From our perspective, the purpose of an RFI (and not an RFP) is to fully evaluate all potential available resource options. To the extent modifications to the COD dates and the project configuration better aligns the proposal to the underlying need, it better enables SPS to conduct a full and complete analysis of replacement options and resources. Based on industry practice, RFIs are intended to serve a discovery purpose and inform the development of future RFPs which would be subject to more rigid processes and rules. RFIs are intended to be flexible in design to facilitate the acquisition of the kind of information that the issuing utility seeks to better understand. In the context of the current solicitation, our expectation would be for SPS to explore each proposal and obtain the maximum amount of information possible. As the RFI was open-ended by design, some proposals are expected to miss the mark and need certain adjustments to adapt to SPS's system needs. Requesting additional pricing options and configurations would be the appropriate course of action for SPS to fully evaluate all options available. To that end, we observed SPS requesting additional pricing options from bidders to reflect different COD dates and interconnection assumptions. In doing so, the modeling reflected additional alternatives that may or may not have conferred economic benefits. Accordingly, we observed that SPS conducted the RFI process in a fair and complete fashion that is in-line with the intent of the solicitation and overall process.

3.3 Results

The RFI received the following response from the market:

- 18 companies participated.
- Eight key technologies proposed:
    - Solar
    - Solar plus storage
    - Wind
    - Gravitational energy storage
    - Combined cycle plus hydrogen storage
    - Liquid air energy storage
    - Flow energy storage
    - Compressed air battery
- Project deployment in five key states, including Texas, New Mexico, Colorado, Kansas, and Oklahoma.

Table 1. Summary of Responses Received

Bidders	Technology	States
Respondent 1	Solar	Texas

Bidders	Technology	States
Respondent 2	Solar, solar plus storage	New Mexico
Respondent 3	Wind	New Mexico
Respondent 4	Solar plus storage	Texas
Respondent 5	Gravitational energy storage	N/A
Respondent 6	Wind	New Mexico, Colorado, Kansas
Respondent 7	Combined cycle plus hydrogen storage	Texas
Respondent 8	Wind	Texas
Respondent 9	Liquid air energy storage	N/A
Respondent 10	Solar	Texas
Respondent 111	Wind	Texas
Respondent 1	Combined cycle	New Mexico
Respondent 12	Flow energy storage	N/A
Respondent 13	Solar, solar plus storage	Texas
Respondent 14	Wind, solar	New Mexico, Texas
Respondent 15	Solar plus storage, wind	Texas
Respondent 16	Technical Information on Resource Technology	N/A
Respondent 17	Solar	Oklahoma
Respondent 18	Compressed air battery	N/A

4. Summary of the Tolk Analysis

To effectively evaluate replacement options, SPS employs the use of a detailed modeling tool which leverages information obtained during the RFI process in conjunction with system information to evaluate the optimal paths forward from an economic merit perspective. For example, if a coal-fired resource is required to retire at a certain date, the model evaluates all replacement options and determines which of the options, as a portfolio or standalone resource, makes economic sense while maintaining adequate reliability in terms of preserving the required operating reserve margin.

SPS utilized EnCompass for the Tolk and Harrington analysis. EnCompass is a power supply planning software that performs the following computations:

- Production cost modeling that determines which electric system resources should be run on a least-cost basis, while respecting known constraints under a set of defined assumptions.
- Optimization of supply resources that, through permutative production cost analyses, identifies the supply portfolio that minimizes total cost while managing to reliability constraints.

A wide variety of tools are available in the marketplace to conduct the analysis. Based on a review of EnCompass' capabilities and the methodology it follows to perform the analysis, we agree with its use as part of the overall approach to optimize the solution. However, in large part, the modeling is sensitive to the following parameters which are input manually:

- Specific scenarios and constraints, around which the model must solve for.
- Input assumptions on which the model calculates the cost of electric production.

The results from the EnCompass software were tabulated on the basis of the Present Value of Revenue Requirements ("PVRR"). Adoption of the revenue requirements comparative perspective is widely adopted in the industry, as this vantage point seeks to evaluate the relative costs passed onto ratepayers. In addition, levelization of the revenue requirements on the basis of net present value normalizes the results to start of the study period ($2022) to facilitate the comparison of options that may have greater short-term versus long-term cost implications. Levelization of revenue requirements is also consistent with industry practices to ensure that the time value of money is considered and captured.

Part of our role as IE is to ensure SPS evaluates all feasible and practical options to address the constraints and that the assumptions taken are reasonable and aligned with industry practice.

4.1 Assumptions

1. **Fuel price forecasts:** SPS inputs a natural gas forecast and coal price forecast into the EnCompass model. The approach to arriving at a consensus fuel price forecast generally entails the weighting or averaging of multiple leading price forecasts available in the market. The coal price forecast leverages specific price information associated with the power plants, which is reasonable given the impact of transportation-related costs, as well as the use of spot coal price forecasts developed by averaging market forecasts provided by industry-leading consulting firms. For natural gas, SPS adopts the

short-term outlook from NYMEX (plus 2 years) and adopts the longer-term outlook from an average of four publications (NYMEX, IHS Energy, S&P Global, and Wood Mackenzie). Guidehouse's market modeling experts have reviewed this approach and confirm that it benchmarks well to our internal forecasts. On similar engagements, we have observed similar approaches used by other utilities. We conclude that the methodology used for the applicable fuel price forecasts is reasonable.

2. **Market electricity prices:** SPS is a member of SPP, which gives it access to a regional market for electricity purchases and sales. To estimate applicable electric prices at which SPS can economically transact, SPS leverages a straight average of long-term on-peak and off-peak implied heat rate forecasts provided by Wood Mackenzie, S&P Global, and IHS Markit for SPP South Hub. Implied heat rates are a gauge of electrical efficiency denominated in MMBtu of natural gas consumption per kilowatt-hour of generation that are equivalent to what would be the breakeven point for power supply. Implied heat rates are multiplied by the gas price forecast to produce an equivalent market energy price. The SPP South Hub is the applicable region at which SPS can conduct electricity transactions. Guidehouse's market modeling experts have reviewed this approach and confirm that it benchmarks well to our internal forecasts. On similar engagements, we have observed similar approaches used by utilities. We conclude that the methodology used for the applicable market electricity price forecast is reasonable.
3. **Load and demand:** To meet regional reliability criteria and to project the energy needs of the SPS service territory, a proper projection of future energy sales and the coincident peak demand is needed for modeling purposes. SPS's methodology entails a forecast of retail energy sales and customers by rate class. Coincident peak demand is forecast at the aggregate SPS level. For customers receiving wholesale service, energy sales and coincident peak demand forecasts are developed according to the individual customer. In large part, SPS used actual monthly historical data to derive all forecasts. As part of the process, two forecasts were derived to conduct sensitivity: the planning forecast based on an 85% probabilistic load forecasting level and a financial forecast, which reflects actual expected load. The purpose of a planning forecast is to ensure reliability even during the worst-case scenario. Planning to this level achieves, typically, a 1 day in 10-year loss of load expectation, which is the standard set by the North American Electric Reliability Corporation that SPS must follow. In addition, the financial forecast reflects what the utility, financially, would realize in a given year based on a median expectation of load conditions. We have reviewed SPS's actual load forecasts and have benchmarked it to our available and modeled forecasts. Based on the review, we conclude that the load and demand forecasts are reasonable and in line with industry practice.
4. **Interconnection cost:** How a resource is connected to the system can have significant bearing on the all-in cost of a generation resource. In addition to the physical connection of the resources, there may be additional costs related to reinforcing the network of the broader area to assure reliable delivery of electricity. For SPS, interconnection studies are conducted by SPP, which receives interconnection requests from resources, groups studies for processing, manages the order in which projects are studied, conducts technical analyses to assure reliable connection, and assigns costs of network infrastructure upgrades required to reliably deliver electricity from the projects. A full and complete study can take a significant amount of time—approximately 18 months for the technical analysis. Constructing the interconnection and identified infrastructure upgrades can take years, putting projects with existing interconnection requests at a significant timing advantage over ones that do not. SPS developed their cost adders

based on upgrades identified for Zones 2 and 6, the relevant regions for SPS territory. By using the SPP estimates, SPS calculated the infrastructure cost adder to connect a resource as $400/kW in its base case. In addition, SPS ran additional sensitivities of $200 and $600/kW to determine the impact of higher or lower than expected interconnection costs than anticipated. This is a reasonable approach and in line with standard industry practices.

4.2 Scenarios

Scenario modeling was conducted to evaluate the impact of changes in COD and operating profiles on the selected portfolio, and in turn, its impact on the Utility's revenue requirements. As the primary driver for Tolk retirement was water resource constraints, options that address this concern were considered in the scenarios, including reduced, seasonal operation, a staggered retirement approach, and an early retirement. To reduce water usage, operations at Tolk would either need to be minimized or eliminated entirely.

Accordingly, SPS defined the following scenarios for consideration:

- **Scenario 1 – Annual Economic Dispatch**
  - Summer only economic dispatch throughout 2021
  - Annual economic dispatch thereafter
  - Both Tolk units retire at end of economically available water - EOY 2025
  - Harrington converted to gas EOY 2024
- **Scenario 2 – Summer Only Economic Dispatch**
  - Summer only economic dispatch 2021 and beyond
  - Both Tolk units retire at end of economically available water - EOY 2032
  - Harrington converted to gas EOY 2024
- **Scenario 3 – Earliest Retirement of Tolk Units**
  - Summer only economic dispatch 2021
  - Annual economic dispatch thereafter
  - Both Tolk units retire EOY 2023
  - Harrington converted to gas EOY 2024
- **Scenario 4 – Staggered Retirement of Tolk Units**
  - Summer only economic dispatch 2021
  - Annual economic dispatch thereafter
  - Unit 1 retires EOY 2023
  - Unit 2 retires at end of economically available water - EOY 2031
  - Harrington converted to gas EOY 2024
- **Scenario 5 – Staggered Retirement of Tolk Units & Seasonal Operations**
  - Summer only economic dispatch
  - Unit 1 retires EOY 2023
  - Unit 2 retires EOY 2032
  - Harrington converted to gas EOY 2024
- **Scenario 6 – Earliest Retirement of Tolk & Harrington Units**
  - Tolk - Summer only economic dispatch 2021

- Tolk - Annual economic dispatch thereafter
- Harrington – Annual economic dispatch in all years
- All Tolk and Harrington Units Retire EOY 2023

The above scenarios capture a range of retirement dates and reduced operational profiles to address water constraints. These include:

1. Retire at the point where water is no longer economically available – both units operating and one unit operating.

2. Earliest retirement feasible for all units.

3. Seasonal operations to potentially minimize replacement capacity costs (assuming such costs exceed ongoing operations at Tolk).

It is noted that in most scenarios, it is assumed that Harrington is converted to gas in the End of Year 2024. Further options for Harrington are separately evaluated under the Harrington Analysis.

After review and discussion with SPS, we agreed that the scenarios presented above represent the spectrum of options available that was primarily driven by the water resource constraint. The options above are shaped by separate analyses conducted to remain within water resource parameters. Replacement options for Tolk are evaluated on an economic basis based on the response from the RFI for resource additions through 2025. For projects post-2025, which would reflect projects not yet in development, SPS used generic resource cost assumptions to meet capacity shortfalls as determined through the use of EnCompass. Generic resources included all thermal resource options, including combine cycle and simple cycle units, to meet capacity needs.

5. Results of the Tolk Analysis

The base case scenarios leverage the planning load forecast with the base case (median) gas price forecast. Table 2 presents the results of the base cases:

Table 2. Summary of PVRR Results, Base Case: Assumes Planning Load, $400/kW Interconnection Cost, and Base Gas Forecast

PVRR Production Cost	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022-2032	Delta from Ref. Case ($M)	NPV ($M) 2022-2041
Scenario 1	236	**$3,449**	$266	**$7,691**	$117	**$12,066**
Scenario 2 (Ref. Case)	$0	**$3,213**	$0	**$7,426**	$0	**$11,949**
Scenario 3	$235	**$3,448**	$271	**$7,696**	$118	**$12,067**
Scenario 4	$61	**$3,274**	$135	**$7,561**	$93	**$12,042**
Scenario 5	$30	**$3,243**	$87	**$7,513**	$33	**$11,982**
Scenario 6	$789	**$4,002**	$1,398	**$8,824**	$1,526	**$13,475**

Guidehouse reviewed the model outputs from each of these scenarios, focusing on the key differences and their drivers among the cases to validate the analyses. We made the following observations:

Prudent utility practice would require the cases be tested under a variety of conditions to stress test the cases against changes in the assumptions. The two factors that have significant impact on modeling results are the load forecast, which sets the reliability margin/capacity need requirement, and the fuel price forecast, which may influence the relative economics of fossil units of varying efficiency against renewable resources. In addition, SPS tested varying assumptions regarding the cost of interconnection since accurate figures are not available until a full study is conducted. SPS conducted a sensitivity analysis of the six scenarios across three load forecasts, three interconnection cost assumptions and three fuel price forecasts for a total of 27 runs. The analysis of Harrington was conducted across three load forecasts (low, planning and financial) and three gas price forecasts (low, base, and high) for 9 total sensitivities for each scenario.

Table 3. Impact of Assumptions on Scenario Ranking

Run No.	Gas Forecast	Load Forecast	Interconnection Cost Assumption	Lowest PVRR Scenario	Next Lowest PVRR Scenario
1	Base	Financial	$200/kW	Scenario 3	Scenario 5
2	Base	Financial	$400/kW	Scenario 2	Scenario 5
3	Base	Financial	$600/kW	Scenario 2	Scenario 5
4	Base	High	$200/kW	Scenario 5	Scenario 2
5	Base	High	$400/kW	Scenario 2	Scenario 5
6	Base	High	$600/kW	Scenario 5	Scenario 2
7	Base	Low	$200/kW	Scenario 2	Scenario 5
8	Base	Low	$400/kW	Scenario 2	Scenario 5
9	Base	Low	$600/kW	Scenario 2	Scenario 5

10	High	Financial	$200/kW	Scenario 3	Scenario 5
11	High	Financial	$400/kW	Scenario 5	Scenario 2
12	High	Financial	$600/kW	Scenario 3	Scenario 5
13	High	High	$200/kW	Scenario 5	Scenario 4
14	High	High	$400/kW	Scenario 5	Scenario 2
15	High	High	$600/kW	Scenario 5	Scenario 4
16	High	Low	$200/kW	Scenario 5	Scenario 2
17	High	Low	$400/kW	Scenario 2	Scenario 5
18	High	Low	$600/kW	Scenario 2	Scenario 5
19	Low	Financial	$200/kW	Scenario 2	Scenario 5
20	Low	Financial	$400/kW	Scenario 2	Scenario 5
21	Low	Financial	$600/kW	Scenario 2	Scenario 5
22	Low	High	$200/kW	Scenario 5	Scenario 2
23	Low	High	$400/kW	Scenario 2	Scenario 5
24	Low	High	$600/kW	Scenario 2	Scenario 5
25	Low	Low	$200/kW	Scenario 2	Scenario 5
26	Low	Low	$400/kW	Scenario 2	Scenario 5
27	Low	Low	$600/kW	Scenario 2	Scenario 5

The highest ranking and most resilient scenario in all cases, as evident in the table above, is Scenario 2. When a particular case maintains a relative cost advantage despite changes in assumptions, it is an indication that the selected case is resilient to such changes and represents the "least regrets" planning scenario available.

The sensitivity analysis does reveal, however, that there are situations where Scenario 5, and to a lesser extent, Scenario 3, have a cost advantage under specified assumptions. There are five (5) total cases where Scenario 2 is not in either of the top two positions. In most cases, Scenario 5 is 2nd to Scenario 2. In virtually all such cases, the NPVRR gap differentiating the cases is relatively narrow (between $0 to $32M over 20 years). The differences between the cases is considered within the planning margin of error, therefore, decisions on the optimal scenario should be rendered from a qualitative risk perspective.

6. Conclusions

We oversaw SPS throughout both the RFI process and the Tolk analysis. With regards to the RFI, the key objective from an IE's perspective was to ensure that all proposals were fully considered and that each respondent was given an equal and fair opportunity to submit additional information as needed to provide the utility with the most advantageous offer possible to the utility and its ratepayers, facilitating a viable economical option to replace the Tolk Generating Station. Based on our observations of the discussions between SPS and respondents, this standard has been met, and specifically for the RFI process, SPS used fair solicitation and evaluation processes. In our review, we observed SPS using a consistent methodology and approach to evaluate the options proposed.

Whether SPS considered available replacement resources was a function of both the responses to the RFI, reflecting projects already in development able to meet the need dates, and generic resource options that SPS has captured in its model as a backstop should there be a shortfall in future capacity needs. The projects received via the RFI were included in the detailed modeling. The generic resource inputs are also consistent with supply options typically considered and available to utilities seeking to address a capacity need. Aside from what was considered and evaluated by SPS, there are no other reasonable and viable options to our knowledge. Therefore, the replacement resources considered is reasonable and consistent with industry practices.

A series of potential Tolk retirement dates and scenarios, given the state of water availability, were considered. A variety of approaches, including early retirement, the latest date in which the Tolk Station could operate with economic water, and a staggered unit-by-unit approach to retirement, were modelled and considered. It is not possible to model every possible date, however, in our view SPS considered a substantial number of intervening dates and approaches driven by the circumstances. Accordingly, SPS considered a range of retirement dates and the scenarios chosen by SPS in our view are reasonable.

Xcel Energy®

2020 Request for Information for Generating Resources

Southwestern Public Service Company

Released September 9, 2020

Table of Contents

Introduction:

This announcement constitutes a Request for Information ("RFI") notice soliciting current pricing, technical characteristics, and other relevant information for potential generating resources. This is not a Request for Proposals ("RFP") or solicitation for formal proposals. This RFI does not constitute a commitment, implied or otherwise, that SPS will take action in this matter. SPS will not be responsible for any costs incurred in furnishing SPS responsive information.

SPS is interested in understanding the current availabilities, flexibilities, and preferences of market participants interested in providing capacity and associated energy to SPS from all generating resource types, including energy storage, whether existing or yet-to-be constructed. SPS is considering the availability of capacity resources for possible future owned generation, build-own-transfers ("BOTs"), and purchased power agreements ("PPAs").

General Background:

- SPS is a New Mexico corporation and wholly-owned electric utility subsidiary of Xcel Energy.
- SPS's total company service territory encompasses a 52,000-square-mile area in eastern and southeastern New Mexico, the Texas Panhandle, and the Texas South Plains and its primary business is generating, transmitting, distributing, and selling electric energy.
- SPS has a long history of providing safe, reliable, value-added service to our customers
- SPS serves 394,220 electric retail customers in Texas and New Mexico.
- As prescribed in the Uncontested Comprehensive Stipulation ("Stipulation") filed at the New Mexico Public Regulation Commission on January 13, 2020 and approved by the New Mexico Public Regulation Commission ("NMPRC") in Case No. 19-00170-UT, the Stipulation requires SPS to submit a robust analysis of the possible abandonment of its Tolk Generating Station Units 1 and 2 (Tolk) and potential means of replacement of those resources (the "Tolk Analysis"). The Tolk Analysis shall include replacement resources priced based on an RFI solicitation. The Tolk Analysis will also consider a scenario in which all SPS's coal-burning units are retired or replaced before 2030.
- SPS will be evaluating multiple scenarios with various capacity replacement dates. The minimum net capacity need is approximately 500 MW beginning summer 2023. The maximum net capacity need is approximately 2,200 MW beginning summer 2025.

Qualifications and Assumptions:

- Expressions of interest should be from existing or proposed generating facilities within the SPS zone or delivered to the SPS zone from existing or proposed sites within the Southwest Power Pool.
- Expressions of interest should include a proposed Commercial Operation Date (“COD”) if the submission is a future resource.
- Expressions of interest should include all capacity, energy, environmental attributes such as Renewable Energy Credits (RECs), and other generation-related services.
- For purposes of this RFI, “renewable energy” refers to electrical power generated by solar, wind, biomass, or other commercially viable renewable energy technologies including energy storage.
- SPS is interested in the availability of capacity and associated energy resources for possible future owned generation, BOTs, and PPAs.
- PPA durations are recommended to be 25 and/or 30 years.
- Interested parties should respond to this RFI within 60 days of issuance.

Specific Information of Interest:

- Project type, including technical characteristics.
- Project site location for delivery within (or to) the SPS system.
- Proposed COD for resource facilities responsive to this RFI, including details on whether a delay in the proposed COD could impact the pricing and if so an estimate of the price of those impact(s).
- Pricing and quantity in megawatts. All pricing in respondent proposals should reflect costs (to the extent applicable) at the time of submittal and should include costs of interconnection to the transmission system if applicable.
- Statement on current interconnection status (if any), and anticipated extent of need for transmission system upgrades for the proposal.
- Proposals must demonstrate an anticipated ability to obtain all required state/local pre-construction approvals and any associated risks to meet the COD.

Content of Submissions:

- Appendix A includes a set of forms applicable to the resource type being submitted.
    - For dispatchable resources the submitter should complete Appendix A-PPA_DIS forms
    - For renewable generation resources the submitter should complete Appendix A-PPA_RENEW forms
    - For Build-Own-Transfer or sale of an existing asset the submitter should complete Appendix A-BOT.
- Some information may be requested on more than one form. Although such requests may be redundant, submitters must provide the information requested on each applicable form.
- SPS will convene a Bidders Meeting for all interested parties to allow for clarifications and any questions that potential bidders may have. See meeting details below.

Bidders Meeting:

Date: September 21, 2020

Time: 1:00PM – 3:00 PM Mountain Daylight Time

Join Zoom Meeting:
https://xcelenergy.zoom.us/j/93175193060?pwd=cVpNeTZvTEkycURIMUhqMlZWL2l4dz09

Meeting ID: 931 7519 3060
Passcode: 270511
One tap mobile
+17209289299,,93175193060#,,,,,,0#,,270511# US (Denver)
+12133388477,,93175193060#,,,,,,0#,,270511# US (Los Angeles)

Dial by your location
+1 720 928 9299 US (Denver)
+1 213 338 8477 US (Los Angeles)
+1 346 248 7799 US (Houston)
+1 206 337 9723 US (Seattle)
+1 312 626 6799 US (Chicago)
+1 646 518 9805 US (New York)
+1 651 372 8299 US (St. Paul)
+1 786 635 1003 US (Miami)
Meeting ID: 931 7519 3060
Passcode: 270511
Find your local number: https://xcelenergy.zoom.us/u/aLUXvN6pb

Proposal Submission Deadline:

Proposals will be accepted until 5:00 P.M. Central Time on **Friday, November 6, 2020**. All Proposals must be transmitted by to the following email address:

SPSTolkAnalysis@xcelenergy.com

Proposals received later than the due date and time indicated will be rejected.

Follow-up Requests

To the extent SPS has questions or seeks clarification regarding a Proposal, SPS may pose follow-up questions. Submitters are not obligated to respond to such follow-up questions, but, are advised that a failure to provide adequate information may lead to a Proposal or a portion of a Proposal being disregarded.

Confidentiality

SPS recognizes that certain information contained in a Proposal submitted may be deemed by the submitter to be confidential. To the extent a submitter believes portions of its Proposal (or any subsequent responses to follow-up questions) constitute confidential material, the submitter should clearly label such material as confidential ("Confidential Material"). SPS will not be responsible for identifying any Confidential Material that has not been designated as such by the submitter. If SPS receives a request from a regulatory or judicial authority to which Confidential Material is responsive, or if SPS receives a request (that SPS reasonably deems to be a valid request) from a party in a regulatory or judicial proceeding to which request SPS determines Confidential Material in the Proposal is responsive, or to the extent otherwise required by law, SPS may provide the Confidential Material pursuant to a confidentiality or protective agreement or order in such proceeding. To the extent Confidential Material is proposed to be disclosed publicly (i.e., not subject to a confidentiality or protective agreement), SPS will notify the submitter as soon as reasonably possible; it is the sole responsibility of the submitter to seek to protect the material subsequent to such notification. SPS may disclose non-Confidential Material at its discretion without prior notice.

Appendix F - PVRR Tables

Planning Load Forecast (Base Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,213	$0	$7,426	$0	$11,949
Scenario 1	$236	$3,449	$266	$7,691	$117	$12,066
Scenario 3	$235	$3,448	$271	$7,696	$118	$12,067
Scenario 4	$61	$3,274	$135	$7,561	$93	$12,042
Scenario 5	$30	$3,243	$87	$7,513	$33	$11,982
Scenario 6	$789	$4,002	$1,398	$8,824	$1,526	$13,475

Financial Load Forecast (Base Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,993	$0	$6,628	$0	$10,388
Scenario 1	$146	$3,140	$165	$6,792	$128	$10,516
Scenario 3	$147	$3,140	$169	$6,797	$48	$10,436
Scenario 4	$38	$3,031	$88	$6,716	$75	$10,462
Scenario 5	$3	$2,996	$28	$6,655	$2	$10,390
Scenario 6	$548	$3,541	$796	$7,424	$755	$11,142

Low Load Forecast (Base Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,809	$0	$5,969	$0	$9,013
Scenario 1	$221	$3,031	$226	$6,196	$128	$9,141
Scenario 3	$150	$2,959	$162	$6,131	$62	$9,075
Scenario 4	$41	$2,851	$79	$6,048	$83	$9,096
Scenario 5	$4	$2,813	$16	$5,986	$9	$9,022
Scenario 6	$559	$3,369	$832	$6,801	$837	$9,850

Planning Load Forecast (Low Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,195	$0	$7,304	$0	$11,504
Scenario 1	$143	$3,338	$173	$7,477	$134	$11,637
Scenario 3	$229	$3,424	$284	$7,588	$185	$11,689
Scenario 4	$107	$3,302	$198	$7,502	$100	$11,604
Scenario 5	$73	$3,268	$134	$7,438	$29	$11,532
Scenario 6	$691	$3,887	$1,248	$8,552	$1,472	$12,976

Financial Load Forecast (Low Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,988	$0	$6,565	$0	$10,115
Scenario 1	$151	$3,139	$178	$6,743	$128	$10,243
Scenario 3	$155	$3,143	$152	$6,717	$48	$10,163
Scenario 4	$39	$3,027	$116	$6,681	$97	$10,212
Scenario 5	$2	$2,989	$37	$6,601	$14	$10,130
Scenario 6	$554	$3,541	$863	$7,428	$935	$11,050

Low Load Forecast (Low Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,809	$0	$5,940	$0	$8,955
Scenario 1	$141	$2,950	$191	$6,132	$150	$9,105
Scenario 3	$158	$2,967	$181	$6,121	$85	$9,040
Scenario 4	$42	$2,850	$133	$6,074	$124	$9,079
Scenario 5	$3	$2,811	$39	$5,979	$23	$8,978
Scenario 6	$564	$3,373	$919	$6,860	$1,033	$9,988

Planning Load Forecast (High Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,276	$0	$7,597	$0	$12,398
Scenario 1	$141	$3,417	$128	$7,725	$79	$12,478
Scenario 3	$209	$3,485	$241	$7,839	$67	$12,466
Scenario 4	$33	$3,310	$36	$7,634	$31	$12,430
Scenario 5	$4	$3,280	$16	$7,613	($0)	$12,398
Scenario 6	$561	$3,837	$1,105	$8,703	$1,258	$13,657

Financial Load Forecast (High Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,054	$0	$6,744	$0	$10,638
Scenario 1	$146	$3,200	$113	$6,857	$71	$10,710
Scenario 3	$146	$3,200	$132	$6,877	$3	$10,641
Scenario 4	$50	$3,104	$80	$6,824	$50	$10,688
Scenario 5	$15	$3,069	$21	$6,765	($3)	$10,635
Scenario 6	$487	$3,541	$678	$7,422	$631	$11,269

Low Load Forecast (High Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,811	$0	$5,939	$0	$9,025
Scenario 1	$148	$2,958	$179	$6,118	$149	$9,174
Scenario 3	$150	$2,960	$181	$6,120	$71	$9,096
Scenario 4	$40	$2,851	$92	$6,031	$78	$9,103
Scenario 5	$6	$2,816	$33	$5,972	$27	$9,052
Scenario 6	$554	$3,365	$792	$6,731	$665	$9,690

Planning Load Forecast (Base Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,226	$0	$7,453	$0	$11,803
Scenario 1	$130	$3,356	$56	$7,509	$26	$11,830
Scenario 3	$170	$3,397	$64	$7,517	$4	$11,807
Scenario 4	$36	$3,262	$12	$7,465	$26	$11,830
Scenario 5	$4	$3,230	($26)	$7,427	($23)	$11,780
Scenario 6	$616	$3,842	$826	$8,279	$890	$12,694

Financial Load Forecast (Base Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,012	$0	$6,678	$0	$10,258
Scenario 1	$145	$3,157	$41	$6,719	$30	$10,289
Scenario 3	$102	$3,114	$10	$6,688	($10)	$10,248
Scenario 4	$39	$3,051	$9	$6,687	$13	$10,272
Scenario 5	$10	$3,022	($4)	$6,674	($10)	$10,248
Scenario 6	$503	$3,515	$633	$7,311	$675	$10,933

Low Load Forecast (Base Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,822	$0	$5,950	$0	$8,918
Scenario 1	$141	$2,964	$100	$6,050	$66	$8,984
Scenario 3	$101	$2,923	$69	$6,019	$17	$8,935
Scenario 4	$37	$2,859	$72	$6,022	$65	$8,983
Scenario 5	($1)	$2,821	$11	$5,960	$3	$8,921
Scenario 6	$520	$3,342	$749	$6,698	$743	$9,661

Planning Load Forecast (Low Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,208	$0	$7,308	$0	$11,398
Scenario 1	$137	$3,346	$90	$7,397	$71	$11,470
Scenario 3	$167	$3,375	$204	$7,511	$130	$11,528
Scenario 4	$50	$3,258	$96	$7,403	$63	$11,461
Scenario 5	$15	$3,224	$25	$7,333	($1)	$11,398
Scenario 6	$724	$3,932	$1,235	$8,543	$1,489	$12,887

Financial Load Forecast (Low Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,988	$0	$6,565	$0	$10,023
Scenario 1	$155	$3,142	$92	$6,657	$72	$10,095
Scenario 3	$124	$3,112	$82	$6,647	$18	$10,042
Scenario 4	$52	$3,040	$94	$6,659	$73	$10,096
Scenario 5	$14	$3,002	$26	$6,591	$2	$10,025
Scenario 6	$527	$3,515	$760	$7,325	$843	$10,866

Low Load Forecast (Low Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,807	$0	$5,936	$0	$8,858
Scenario 1	$152	$2,959	$128	$6,064	$110	$8,968
Scenario 3	$112	$2,919	$105	$6,041	$60	$8,919
Scenario 4	$52	$2,859	$112	$6,048	$99	$8,958
Scenario 5	$4	$2,811	$28	$5,964	$14	$8,873
Scenario 6	$539	$3,346	$822	$6,758	$947	$9,806

Planning Load Forecast (High Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,247	$0	$7,567	$0	$12,100
Scenario 1	$126	$3,374	$24	$7,591	$22	$12,122
Scenario 3	$156	$3,403	$36	$7,604	$7	$12,107
Scenario 4	$34	$3,282	($3)	$7,565	($7)	$12,093
Scenario 5	$5	$3,252	($25)	$7,543	($12)	$12,088
Scenario 6	$593	$3,840	$776	$8,344	$763	$12,863

Financial Load Forecast (High Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,021	$0	$6,765	$0	$10,493
Scenario 1	$132	$3,154	($10)	$6,755	($29)	$10,465
Scenario 3	$114	$3,135	($24)	$6,741	($102)	$10,391
Scenario 4	$38	$3,060	($12)	$6,753	($16)	$10,477
Scenario 5	$3	$3,025	($41)	$6,724	($51)	$10,442
Scenario 6	$513	$3,534	$612	$7,376	$510	$11,003

Low Load Forecast (High Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,824	$0	$5,970	$0	$8,909
Scenario 1	$142	$2,966	$67	$6,037	$46	$8,955
Scenario 3	$104	$2,928	$40	$6,009	$0	$8,909
Scenario 4	$39	$2,863	$22	$5,992	$29	$8,939
Scenario 5	$3	$2,827	($15)	$5,955	($12)	$8,897
Scenario 6	$514	$3,338	$657	$6,626	$596	$9,505

Planning Load Forecast (Base Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,205	$0	$7,445	$0	$12,076
Scenario 1	$241	$3,446	$238	$7,684	$78	$12,153
Scenario 3	$241	$3,447	$213	$7,659	$43	$12,118
Scenario 4	$103	$3,309	$149	$7,595	$43	$12,119
Scenario 5	$72	$3,277	$109	$7,555	($15)	$12,060
Scenario 6	$747	$3,952	$1,217	$8,663	$1,170	$13,245

Financial Load Forecast (Base Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,993	$0	$6,628	$0	$10,467
Scenario 1	$215	$3,208	$240	$6,868	$94	$10,561
Scenario 3	$154	$3,148	$161	$6,789	$21	$10,489
Scenario 4	$111	$3,105	$195	$6,823	$66	$10,533
Scenario 5	$75	$3,068	$136	$6,764	$7	$10,474
Scenario 6	$633	$3,626	$945	$7,573	$865	$11,332

Low Load Forecast (Base Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,809	$0	$5,941	$0	$9,077
Scenario 1	$221	$3,031	$272	$6,213	$112	$9,189
Scenario 3	$157	$2,967	$185	$6,126	$44	$9,121
Scenario 4	$117	$2,926	$241	$6,182	$96	$9,173
Scenario 5	$78	$2,888	$155	$6,096	$15	$9,091
Scenario 6	$643	$3,452	$1,006	$6,947	$973	$10,050

Planning Load Forecast (Low Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,195	$0	$7,305	$0	$11,575
Scenario 1	$211	$3,406	$255	$7,560	$103	$11,678
Scenario 3	$245	$3,440	$253	$7,558	$123	$11,698
Scenario 4	$107	$3,302	$211	$7,516	$77	$11,652
Scenario 5	$73	$3,268	$137	$7,442	$5	$11,580
Scenario 6	$844	$4,039	$1,655	$8,960	$1,996	$13,571

Financial Load Forecast (Low Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,988	$0	$6,592	$0	$10,167
Scenario 1	$219	$3,207	$215	$6,807	$86	$10,254
Scenario 3	$155	$3,143	$128	$6,720	$15	$10,182
Scenario 4	$114	$3,102	$202	$6,794	$98	$10,265
Scenario 5	$75	$3,063	$113	$6,706	$3	$10,170
Scenario 6	$580	$3,568	$923	$7,515	$1,035	$11,202

Low Load Forecast (Low Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,809	$0	$5,970	$0	$9,001
Scenario 1	$225	$3,033	$241	$6,210	$127	$9,128
Scenario 3	$158	$2,967	$143	$6,113	$63	$9,064
Scenario 4	$42	$2,850	$144	$6,113	$113	$9,114
Scenario 5	$3	$2,811	$41	$6,011	$17	$9,018
Scenario 6	$635	$3,444	$1,027	$6,997	$1,182	$10,183

Planning Load Forecast (High Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,339	$0	$7,745	$0	$12,585
Scenario 1	$124	$3,463	$48	$7,793	$37	$12,622
Scenario 3	$128	$3,467	$98	$7,844	$11	$12,596
Scenario 4	$29	$3,368	($22)	$7,724	($18)	$12,567
Scenario 5	($2)	$3,337	($39)	$7,706	($41)	$12,544
Scenario 6	$612	$3,951	$916	$8,662	$827	$13,412

Financial Load Forecast (High Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$3,031	$0	$6,710	$0	$10,768
Scenario 1	$213	$3,244	$210	$6,920	$67	$10,835
Scenario 3	$146	$3,177	$153	$6,863	($17)	$10,752
Scenario 4	$108	$3,139	$171	$6,882	$52	$10,821
Scenario 5	$73	$3,104	$126	$6,836	($4)	$10,764
Scenario 6	$594	$3,625	$880	$7,590	$718	$11,486

Low Load Forecast (High Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2025	Delta ($M)	NPV ($M) 2022 - 2032	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$2,811	$0	$5,939	$0	$9,119
Scenario 1	$217	$3,028	$259	$6,198	$106	$9,225
Scenario 3	$157	$2,968	$187	$6,126	$46	$9,164
Scenario 4	$114	$2,925	$202	$6,141	$78	$9,197
Scenario 5	$78	$2,888	$148	$6,086	$10	$9,129
Scenario 6	$639	$3,449	$944	$6,883	$789	$9,907

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S 2021 INTEGRATED RESOURCE PLAN FOR NEW MEXICO,

SOUTHWESTERN PUBLIC SERVICE COMPANY,

APPLICANT.

CASE NO. 21-00169-UT

CERTIFICATE OF SERVICE

I certify that true and correct copies of *Southwestern Public Service Company's 2021 Tolk Analysis* were electronically sent to each of the following on this 30th day of June 2021:

Dana S. Hardy	dhardy@hinklelawfirm.com;
Sarah Merrick	sarahmerrick@eversheds-sutherland.com;
Will DuBois	Will.w.dubois@xcelenergy.com;
William Grant	William.a.grant@xcelenergy.com;
Mario A. Contreras	Mario.a.contreras@xcelenergy.com;
Zoe E. Lees	Zoe.E.Lees@xcelenergy.com;
Mark A. Walker	Mark.A.Walker@xcelenergy.com;
Phillip Oldham	phillip.oldham@tklaw.com;
Katherine Coleman	katie.coleman@tklaw.com;
Michael McMillin	Michael.mcmillin@tklaw.com;
TKLaw office	tk.eservice@tklaw.com;
Melissa Trevino	Melissa_Trevino@oxy.com;
Jeffrey Pollock	jcp@pollockinc.com;
Joan Drake	jdrake@modrall.com;
Perry Robinson	Perry.Robinson@urenco.com;
Michael P. Gorman	mgorman@consultbai.com;
Amanda Alderson	aalderson@consultbai.com;
William Templeman	wtempleman@cmtisantafe.com;
Michael J. Moffett	mmoffett@cmtisantafe.com;
Cholla Khoury	ckhoury@nmag.gov;
Gideon Elliot	gelliot@nmag.gov;
Jennifer Van Wiel	jvanwiel@nmag.gov;
Andrea Crane	ctcolumbia@aol.com;
Doug Gegax	dgegax@nmsu.edu;
Jason Marks	lawoffice@jasonmarks.com;
Lauren Hogrewe	lauren.hogrewe@sierraclub.org;
Joshua Smith	Joshua.smith@sierraclub.org;
Dru Spiller	Dru.spiller@sierraclub.org;
Matthew Miller	Matthew.miller@sierraclub.org;
Stephanie Dzur	Stephanie@Dzur-Law.com;
Don Hancock	Sricdon@earthlink.net;
April Elliott	ccae@elliottanalytics.com;
Julia Broggi	jbroggi@hollandhart.com;
A.J. Gross	ajgross@hollandhart.com;
Luke Tougas	l.tougas@cleanenergyregresearch.com;
Mike Gallager	mgallagher@leacounty.net;
Jane L. Yee	jyee@cabq.gov;
Randy Bartell	rbartell@montand.com;
Sharon Shaheen	sshaheen@montand.com;
Steve W. Chris	Stephen.Chriss@walmart.com;
David Austin Rueschhoff	darueschhoff@hollandhart.com;
Thorvald A. Nelson	tnelson@hollandhart.com;
Nikolas Stoffel	nsstoffel@hollandhart.com;
Adele Lee	aclee@hollandhart.com;
Gina Gargano-Amari	glgarganoamari@hollandhart.com;
B. Tyler	bltyler@hollandhart.com;
Steven S. Michel	smichel@westernresources.org;
Cydney Beadles	cydney.beadles@westernresources.org;
April Elliott	april.elliott@westernresources.org;
Pat O'Connell	pat.oconnell@westernresources.org;
Maj Holly L. Buchanan	Holly.buchanan.1@us.af.mil;
Mr. Thomas Jernigan	Thomas.Jernigan.3@us.af.mil;
Capt Robert L. Friedman	Robert.Friedman.5@us.af.mil;
Mrs. Ebony M. Payton	Ebony.Payton.ctr@us.af.mil;
TSgt Arnold Braxton	Arnold.Braxton@us.af.mil;
Steve Seelye	sseelye@theprimegroupllc.com;
Bradford Borman	Bradford.Borman@state.nm.us;
John Bogatko	John.Bogatko@state.nm.us;
Milo Chavez	Milo.Chavez@state.nm.us;
Marc Tupler	Marc.Tupler@state.nm.us;
John Reynolds	john.reynolds@state.nm.us;
Judith Amer	Judith.Amer@state.nm.us;
Jack Sidler	Jack.Sidler@state.nm.us;
Elisha Leyba-Tercero	Elisha.Leyba-Tercero@state.nm.us;
Gabriella Dasheno	Gabriella.Dasheno@state.nm.us;
Georgette Ramie	Georgette.Ramie@state.nm.us;
David Ault	David.Ault@state.nm.us;
Peggy Martinez-Rael	Peggy.Martinez-Rael@state.nm.us;
Elizabeth Ramirez	Elizabeth.Ramirez@state.mn.us;
Gilbert Fuentes	GilbertT.Fuentes@state.nm.us;
Andrew Unsicker	andrew.unsicker@us.af.mil;
Thomas Domme	tdomme@tecoenergy.com;
Rebecca Carter	racarter@tecoenergy.com;
Nicole V. Strauser	nvstrauser@tecoenergy.com;

Linda L. Hudgins	linda.l.hudgins@xcelenergy.com;
Nann M. Winter	nwinter@stelznerlaw.com;
Adam Bickford	abickford@swenergy.org;
Sally Wilhelms	swilhelms@consultbai.com;
Rick Gilliam	rick@votesolar.org;
Kellie Barahona	kellie.barahona@tklaw.com;
Matthew Marchant	matthew.marchant@hollyfrontier.com;
Antonio Sanchez Jr.	sancheza@rcec.coop;
Chuck Pinson	cpinson@cvecoop.org;
Daniel A. Najjar	dnajjar@virtuelaw.com;
Carla R. Najjar	csnajjar@virtuelaw.com;
John Caldwell	jcaldwell@leacounty.net;
Ramona Blaber	ramona.blaber@sierraclub.org
Brian J. Haverly	bjh@keleher-law.com;
Sara Gersen	sgersen@earthjustice.org;
Randy Childress	randy@childresslaw.com;
Randall Woolridge	jrwoolridge@gmail;
Peter Gould	pgouldlaw@aol.com;
David Van Winkle	david@vw77.com;
Katelyn Hart	Katelyn.hart@gknet.com;
Anthony J. Trujillo	ajt@gknet.com;
Judith Amer	Judith.Amer@state.nm.us;

Respectfully submitted,
<u>/s/ Casey Settles</u>
Casey Settles
Southwestern Public Service Company
790 S. Buchanan, 7th Floor
Amarillo, TX 79101
(806)378-2462
Casey.Settles@xcelenergy.com

Appendix I - Harrington PVRR Tables

Planning Load Forecast (Base Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,450	$0	$ 6,861	$0	$ 11,949
Scenario 1	$168	$ 2,618	$148	$ 7,009	$123	$ 12,072
Scenario 3	($10)	$ 2,440	$251	$ 7,112	$439	$ 12,388
Scenario 4	($10)	$ 2,440	$436	$ 7,297	$695	$ 12,644
Scenario 5	$92	$ 2,542	$58	$ 6,919	$62	$ 12,011
Scenario 6	$39	$ 2,490	$11	$ 6,872	($5)	$ 11,944

Financial Load Forecast (Base Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,295	$0	$ 6,155	$0	$ 10,388
Scenario 1	$165	$ 2,460	$82	$ 6,237	$47	$ 10,435
Scenario 3	($10)	$ 2,284	$257	$ 6,412	$443	$ 10,831
Scenario 4	($10)	$ 2,284	$444	$ 6,599	$698	$ 11,085
Scenario 5	$92	$ 2,386	$32	$ 6,187	$27	$ 10,415
Scenario 6	$40	$ 2,334	($10)	$ 6,145	($29)	$ 10,358

Planning Load Forecast (Low Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,443	$0	$ 6,747	$0	$ 11,504
Scenario 1	$165	$ 2,608	$168	$ 6,914	$181	$ 11,685
Scenario 3	($10)	$ 2,433	$271	$ 7,018	$485	$ 11,989
Scenario 4	($10)	$ 2,433	$459	$ 7,206	$754	$ 12,258
Scenario 5	$92	$ 2,535	$55	$ 6,802	$71	$ 11,575
Scenario 6	$39	$ 2,483	($15)	$ 6,731	($31)	$ 11,473

Financial Load Forecast (Low Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,294	$0	$ 6,088	$0	$ 10,115
Scenario 1	$160	$ 2,453	$93	$ 6,181	$92	$ 10,207
Scenario 3	($10)	$ 2,283	$278	$ 6,367	$495	$ 10,610
Scenario 4	($10)	$ 2,283	$469	$ 6,557	$765	$ 10,880
Scenario 5	$92	$ 2,385	$1	$ 6,089	($5)	$ 10,111
Scenario 6	$40	$ 2,333	($26)	$ 6,062	($29)	$ 10,086

Planning Load Forecast (High Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,479	$0	$ 7,016	$0	$ 12,398
Scenario 1	$173	$ 2,653	$115	$ 7,131	$51	$ 12,449
Scenario 3	($10)	$ 2,469	$235	$ 7,251	$328	$ 12,726
Scenario 4	($10)	$ 2,469	$420	$ 7,435	$581	$ 12,979
Scenario 5	$92	$ 2,571	$24	$ 7,040	$18	$ 12,416
Scenario 6	$39	$ 2,519	($22)	$ 6,994	($24)	$ 12,375

Financial Load Forecast (High Gas - $400/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,329	$0	$ 6,266	$0	$ 10,638
Scenario 1	$160	$ 2,489	$47	$ 6,313	$24	$ 10,662
Scenario 3	($10)	$ 2,319	$236	$ 6,503	$352	$ 10,990
Scenario 4	($10)	$ 2,319	$422	$ 6,688	$605	$ 11,243
Scenario 5	$92	$ 2,421	$47	$ 6,313	$17	$ 10,656
Scenario 6	$40	$ 2,369	($15)	$ 6,252	($28)	$ 10,611

Planning Load Forecast (Base Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,452	$0	$ 6,886	$0	$ 11,803
Scenario 1	$160	$ 2,612	($59)	$ 6,826	$67	$ 11,870
Scenario 3	($10)	$ 2,442	$225	$ 7,110	$418	$ 12,221
Scenario 4	($10)	$ 2,442	$422	$ 7,307	$675	$ 12,478
Scenario 5	$92	$ 2,544	($8)	$ 6,878	($5)	$ 11,798
Scenario 6	$39	$ 2,491	($31)	$ 6,854	($26)	$ 11,777

Financial Load Forecast (Base Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,302	$0	$ 6,203	$0	$ 10,258
Scenario 1	$160	$ 2,462	$3	$ 6,206	$16	$ 10,275
Scenario 3	($10)	$ 2,292	$271	$ 6,474	$459	$ 10,718
Scenario 4	($10)	$ 2,292	$415	$ 6,618	$686	$ 10,944
Scenario 5	$92	$ 2,394	($33)	$ 6,169	($18)	$ 10,240
Scenario 6	$40	$ 2,342	($10)	$ 6,193	($18)	$ 10,240

Planning Load Forecast (Low Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,448	$0	$ 6,753	$0	$ 11,398
Scenario 1	$163	$ 2,610	$74	$ 6,827	$63	$ 11,462
Scenario 3	($8)	$ 2,440	$284	$ 7,037	$493	$ 11,892
Scenario 4	($13)	$ 2,435	$452	$ 7,205	$759	$ 12,157
Scenario 5	$95	$ 2,542	$23	$ 6,776	$19	$ 11,418
Scenario 6	$39	$ 2,487	$3	$ 6,756	($19)	$ 11,379

Financial Load Forecast (Low Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,294	$0	$ 6,088	$0	$ 10,023
Scenario 1	$163	$ 2,456	$23	$ 6,111	$26	$ 10,049
Scenario 3	($11)	$ 2,283	$275	$ 6,363	$495	$ 10,519
Scenario 4	($11)	$ 2,283	$465	$ 6,554	$764	$ 10,788
Scenario 5	$92	$ 2,385	$32	$ 6,120	$27	$ 10,050
Scenario 6	$43	$ 2,336	($12)	$ 6,076	($36)	$ 9,988

Planning Load Forecast (High Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,462	$0	$ 6,991	$0	$ 12,100
Scenario 1	$160	$ 2,622	$1	$ 6,992	($1)	$ 12,099
Scenario 3	($10)	$ 2,452	$235	$ 7,226	$357	$ 12,457
Scenario 4	($10)	$ 2,452	$420	$ 7,411	$614	$ 12,714
Scenario 5	$92	$ 2,554	($87)	$ 6,904	$34	$ 12,134
Scenario 6	$40	$ 2,502	($26)	$ 6,965	($20)	$ 12,080

Financial Load Forecast (High Gas - $200/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,302	$0	$ 6,280	$0	$ 10,493
Scenario 1	$168	$ 2,471	($69)	$ 6,211	($100)	$ 10,393
Scenario 3	($10)	$ 2,292	$221	$ 6,500	$343	$ 10,837
Scenario 4	($10)	$ 2,292	$391	$ 6,671	$591	$ 11,084
Scenario 5	$92	$ 2,394	($38)	$ 6,242	($40)	$ 10,453
Scenario 6	$40	$ 2,342	($45)	$ 6,234	($55)	$ 10,438

Planning Load Forecast (Base Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,446	$0	$ 6,873	$0	$ 12,076
Scenario 1	$160	$ 2,605	$176	$ 7,049	$175	$ 12,251
Scenario 3	($10)	$ 2,435	$224	$ 7,097	$417	$ 12,492
Scenario 4	($10)	$ 2,435	$409	$ 7,282	$665	$ 12,741
Scenario 5	$92	$ 2,537	$95	$ 6,968	$87	$ 12,163
Scenario 6	$39	$ 2,485	($13)	$ 6,860	($31)	$ 12,044

Financial Load Forecast (Base Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,295	$0	$ 6,155	$0	$ 10,467
Scenario 1	$160	$ 2,454	$106	$ 6,261	$106	$ 10,573
Scenario 3	($10)	$ 2,284	$257	$ 6,412	$443	$ 10,911
Scenario 4	($10)	$ 2,284	$444	$ 6,599	$698	$ 11,165
Scenario 5	$92	$ 2,387	$2	$ 6,157	$20	$ 10,487
Scenario 6	$40	$ 2,334	($6)	$ 6,149	($31)	$ 10,437

Planning Load Forecast (Low Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,443	$0	$ 6,748	$0	$ 11,575
Scenario 1	$160	$ 2,603	$232	$ 6,979	$266	$ 11,841
Scenario 3	($10)	$ 2,433	$276	$ 7,024	$498	$ 12,073
Scenario 4	($10)	$ 2,433	$461	$ 7,209	$765	$ 12,340
Scenario 5	$103	$ 2,546	$105	$ 6,852	$125	$ 11,700
Scenario 6	$40	$ 2,483	($0)	$ 6,747	($13)	$ 11,562

Financial Load Forecast (Low Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,294	$0	$ 6,107	$0	$ 10,167
Scenario 1	$171	$ 2,465	$111	$ 6,218	$141	$ 10,308
Scenario 3	($10)	$ 2,283	$260	$ 6,367	$491	$ 10,658
Scenario 4	($10)	$ 2,283	$450	$ 6,557	$761	$ 10,928
Scenario 5	$92	$ 2,385	($18)	$ 6,089	$17	$ 10,185
Scenario 6	$39	$ 2,333	($23)	$ 6,084	($16)	$ 10,151

Planning Load Forecast (High Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,520	$0	$ 7,163	$0	$ 12,585
Scenario 1	$126	$ 2,646	$40	$ 7,203	$125	$ 12,710
Scenario 3	($56)	$ 2,464	$44	$ 7,207	$277	$ 12,862
Scenario 4	($44)	$ 2,476	$279	$ 7,443	$537	$ 13,122
Scenario 5	$51	$ 2,570	($64)	$ 7,100	$53	$ 12,638
Scenario 6	$40	$ 2,559	($1)	$ 7,162	($14)	$ 12,571

Financial Load Forecast (High Gas - $600/kW network upgrades)

	Action Period		Decision Period		Planning Period	
Scenario	Delta ($M)	NPV ($M) 2022-2024	Delta ($M)	NPV ($M) 2022 - 2031	Delta ($M)	NPV ($M) 2022 - 2041
Scenario 2	$0	$ 2,315	$0	$ 6,231	$0	$ 10,768
Scenario 1	$160	$ 2,475	$96	$ 6,327	$86	$ 10,854
Scenario 3	($10)	$ 2,305	$227	$ 6,458	$346	$ 11,114
Scenario 4	($10)	$ 2,305	$412	$ 6,643	$598	$ 11,366
Scenario 5	$92	$ 2,407	$2	$ 6,233	$16	$ 10,784
Scenario 6	$40	$ 2,355	($6)	$ 6,225	($24)	$ 10,745

Scenario Expansion Plan - Base Gas / No Carbon

		Most Cost-Effective Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW)	**Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW)**	**Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW)**
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2022	Plant X1 - 39 MW Plant X2 - 70 MW Plant X3 - 0 MW Cunningham 1 - 42 MW Nichols 1 - 112 MW			
2023	Nichols 2 - 111 MW			
2024	BlackHawk 1 - 111.685 MW BlackHawk 2 - 111.685 MW CapRock Wind - 80 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_006a - 150 MW
2025	Cunningham 2 - 183 MW Maddox 2 - 69 MW Maddox 3 - 0 MW San Juan Wind - 120 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW
2026		Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW	Solar Generic - 40 MW Wind RFI W_001k - 500 MW
2027	Plant X 4 - 191 MW Spinning Spur Wind - 161 MW Wildorado Wind - 161 MW			
2028	Maddox 1 - 112 MW			CT F Generic - 233.3 MW
2029				CT F Generic - 233.3 MW
2030	National Wind - 0.7 MW Nichols 3 - 246 MW		CT F Generic - 233.3 MW	CT F Generic - 233.3 MW
2031	Jones 1 - 243 MW SunEd 4 Solar - 10 MW SunEd 3 Solar - 10 MW SunEd 2 Solar - 10 MW SunEd 1 Solar - 10 MW SunEd 5 Solar - 10 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2032	Tolk 1 - 532 MW Tolk 2 - 537 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2033	Hobbs CC - 604 MW MesaLands Wind - 1.48 MW	CT F Generic - 466.6 MW Solar Generic - 410 MW Battery Generic - 110 MW	CT F Generic - 466.6 MW Solar Generic - 200 MW	CT F Generic - 466.6 MW Solar Generic - 430 MW Battery Generic - 30 MW

Scenario Expansion Plan - Base Gas / No Carbon

		Most Cost-Effective Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW)	**Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW)**	**Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW)**
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2034	Jones 2 - 243 MW Quay County - 23 MW Mammoth Wind - 200 MW PaloDuro Wind - 250 MW	CT F Generic - 466.6 MW Solar Generic - 740 MW	CT F Generic - 233.3 MW Solar Generic - 780 MW	CT F Generic - 233.3 MW Solar Generic - 930 MW
2035	Roosevelt Wind - 250 MW	CT F Generic - 233.3 MW Solar Generic - 210 MW	CT F Generic - 233.3 MW Solar Generic - 180 MW	CT F Generic - 233.3 MW Solar Generic - 100 MW
2036	Harrington 1 - Gas - 340 MW	Solar Generic - 60 MW	Solar Generic - 100 MW	CT F Generic - 233.3 MW
2037		CT F Generic - 233.3 MW Solar Generic - 100 MW	CT F Generic - 233.3 MW	CT F Generic - 233.3 MW
2038	Harrington 2 - Gas - 355 MW			
2039		CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 90 MW
2040	Harrington 3 - Gas - 355 MW Cunningham 3 - 106 MW Cunningham 4 - 101 MW	Solar Generic - 40 MW	Solar Generic - 60 MW	Solar Generic - 40 MW
2041	Rosewell Solar - 70 MW Chaves County Solar - 70 MW	CT F Generic - 466.6 MW Solar Generic - 220 MW Battery Generic - 70 MW	CT F Generic - 466.6 MW Solar Generic - 250 MW Battery Generic - 10 MW	CT F Generic - 466.6 MW Solar Generic - 250 MW Battery Generic - 30 MW

Scenario Expansion Plan - Low Gas / No Carbon

		Alternative Resource Portfolio (Low Gas / Financial Load Forecast / $400/kW)	Alternative Resource Portfolio (Low Gas / Low Load Forecast / $400/kW)	Alternative Resource Portfolio (Low Gas / Planning Load Forecast / $400/kW)
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2022	Plant X1 - 39 MW Plant X2 - 70 MW Plant X3 - 0 MW Cunningham 1 - 42 MW Nichols 1 - 112 MW			
2023	Nichols 2 - 111 MW			
2024	BlackHawk 1 - 111.685 MW BlackHawk 2 - 111.685 MW CapRock Wind - 80 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW
2025	Cunningham 2 - 183 MW Maddox 2 - 69 MW Maddox 3 - 0 MW San Juan Wind - 120 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW
2026				Solar Generic - 20 MW
2027	Plant X 4 - 191 MW Spinning Spur Wind - 161 MW Wildorado Wind - 161 MW			
2028	Maddox 1 - 112 MW			CT F Generic - 466.6 MW
2029				
2030	National Wind - 0.7 MW Nichols 3 - 246 MW	CT F Generic - 233.3 MW	CT F Generic - 233.3 MW	CT F Generic - 466.6 MW
2031	Jones 1 - 243 MW SunEd 4 Solar - 10 MW SunEd 3 Solar - 10 MW SunEd 2 Solar - 10 MW SunEd 1 Solar - 10 MW SunEd 5 Solar - 10 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2032	Tolk 1 - 532 MW Tolk 2 - 537 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2033	Hobbs CC - 604 MW MesaLands Wind - 1.48 MW	CT F Generic - 466.6 MW Solar Generic - 370 MW	CT F Generic - 466.6 MW Solar Generic - 390 MW	CT F Generic - 466.6 MW Solar Generic - 380 MW

Scenario Expansion Plan - Low Gas / No Carbon

		Alternative Resource Portfolio (Low Gas / Financial Load Forecast / $400/kW)	**Alternative Resource Portfolio (Low Gas / Low Load Forecast / $400/kW)**	**Alternative Resource Portfolio (Low Gas / Planning Load Forecast / $400/kW)**
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2034	Jones 2 - 243 MW Quay County - 23 MW Mammoth Wind - 200 MW PaloDuro Wind - 250 MW	CT F Generic - 466.6 MW Solar Generic - 400 MW	CT F Generic - 466.6 MW Solar Generic - 380 MW	CT F Generic - 466.6 MW Solar Generic - 470 MW
2035	Roosevelt Wind - 250 MW	CT F Generic - 233.3 MW Solar Generic - 180 MW	CT F Generic - 466.6 MW	CT F Generic - 233.3 MW Solar Generic - 200 MW
2036	Harrington 1 - Gas - 340 MW	Solar Generic - 150 MW	CT F Generic - 233.3 MW	Solar Generic - 220 MW
2037		CT F Generic - 233.3 MW Solar Generic - 140 MW		CT F Generic - 233.3 MW
2038	Harrington 2 - Gas - 355 MW			Solar Generic - 40 MW
2039		CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 60 MW
2040	Harrington 3 - Gas - 355 MW Cunningham 3 - 106 MW Cunningham 4 - 101 MW	Solar Generic - 50 MW		Solar Generic - 100 MW
2041	Rosewell Solar - 70 MW Chaves County Solar - 70 MW	CT F Generic - 466.6 MW Solar Generic - 140 MW	CT F Generic - 466.6 MW Solar Generic - 300 MW	CT F Generic - 466.6 MW Solar Generic - 350 MW Battery Generic - 10 MW

Scenario Expansion Plan - High Gas / No Carbon

		Alternative Resource Portfolio (High Gas / Financial Load Forecast / $400/kW)	Alternative Resource Portfolio (High Gas / Low Load Forecast / $400/kW)	Alternative Resource Portfolio (High Gas / Planning Load Forecast / $400/kW)
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2022	Plant X1 - 39 MW Plant X2 - 70 MW Plant X3 - 0 MW Cunningham 1 - 42 MW Nichols 1 - 112 MW			
2023	Nichols 2 - 111 MW			
2024	BlackHawk 1 - 111.685 MW BlackHawk 2 - 111.685 MW CapRock Wind - 80 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_003d - 300 MW Wind RFI W_005a - 250 MW Wind RFI W_006a - 150 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_003d - 300 MW Wind RFI W_005a - 250 MW Wind RFI W_006a - 150 MW
2025	Cunningham 2 - 183 MW Maddox 2 - 69 MW Maddox 3 - 0 MW San Juan Wind - 120 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW Solar RFI S_001a - 385 MW
2026		Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW
2027	Plant X 4 - 191 MW Spinning Spur Wind - 161 MW Wildorado Wind - 161 MW			
2028	Maddox 1 - 112 MW			
2029				CT F Generic - 233.3 MW
2030	National Wind - 0.7 MW Nichols 3 - 246 MW	Solar Generic - 110 MW		CT F Generic - 466.6 MW
2031	Jones 1 - 243 MW SunEd 4 Solar - 10 MW SunEd 3 Solar - 10 MW SunEd 2 Solar - 10 MW SunEd 1 Solar - 10 MW SunEd 5 Solar - 10 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2032	Tolk 1 - 532 MW Tolk 2 - 537 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2033	Hobbs CC - 604 MW MesaLands Wind - 1.48 MW	CT F Generic - 466.6 MW Solar Generic - 430 MW Battery Generic - 20 MW	CT F Generic - 466.6 MW Solar Generic - 360 MW Battery Generic - 110 MW	CT F Generic - 466.6 MW Solar Generic - 140 MW Battery Generic - 20 MW

Scenario Expansion Plan - High Gas / No Carbon

		Alternative Resource Portfolio (High Gas / Financial Load Forecast / $400/kW)	Alternative Resource Portfolio (High Gas / Low Load Forecast / $400/kW)	Alternative Resource Portfolio (High Gas / Planning Load Forecast / $400/kW)
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2034	Jones 2 - 243 MW Quay County - 23 MW Mammoth Wind - 200 MW PaloDuro Wind - 250 MW	CT F Generic - 233.3 MW Solar Generic - 610 MW	CT F Generic - 233.3 MW Solar Generic - 760 MW	CT F Generic - 233.3 MW Solar Generic - 800 MW
2035	Roosevelt Wind - 250 MW	CT F Generic - 233.3 MW Solar Generic - 150 MW	CT F Generic - 233.3 MW Solar Generic - 200 MW	CT F Generic - 233.3 MW Solar Generic - 200 MW
2036	Harrington 1 - Gas - 340 MW	Solar Generic - 120 MW	Solar Generic - 100 MW	Solar Generic - 120 MW
2037		CT F Generic - 233.3 MW Solar Generic - 80 MW	CT F Generic - 233.3 MW	CT F Generic - 233.3 MW Solar Generic - 30 MW
2038	Harrington 2 - Gas - 355 MW	Solar Generic - 190 MW	Solar Generic - 40 MW	Solar Generic - 100 MW
2039		CT F Generic - 466.6 MW Solar Generic - 100 MW Battery Generic - 10 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 180 MW
2040	Harrington 3 - Gas - 355 MW Cunningham 3 - 106 MW Cunningham 4 - 101 MW	Solar Generic - 40 MW	Solar Generic - 80 MW	Solar Generic - 440 MW Battery Generic - 10 MW
2041	Rosewell Solar - 70 MW Chaves County Solar - 70 MW	CT F Generic - 466.6 MW Solar Generic - 260 MW Battery Generic - 70 MW	CT F Generic - 466.6 MW Solar Generic - 300 MW Battery Generic - 70 MW	CT F Generic - 466.6 MW Solar Generic - 480 MW Battery Generic - 120 MW

Scenario Expansion Plan - Financial Load / Carbon

		Alternative Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW / $8 Carbon	Alternative Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW / $20 Carbon	Alternative Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW / $40 Carbon
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2022	Plant X1 - 39 MW Plant X2 - 70 MW Plant X3 - 0 MW Cunningham 1 - 42 MW Nichols 1 - 112 MW			
2023	Nichols 2 - 111 MW			
2024	BlackHawk 1 - 111.685 MW BlackHawk 2 - 111.685 MW CapRock Wind - 80 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_005a - 250 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_005a - 250 MW Wind RFI W_006a - 150 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_005a - 250 MW Wind RFI W_006a - 150 MW
2025	Cunningham 2 - 183 MW Maddox 2 - 69 MW Maddox 3 - 0 MW San Juan Wind - 120 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW Solar RFI S_001a - 385 MW	Wind RFI W_002b - 1000 MW Solar RFI S_001a - 385 MW Solar RFI S_007a - 500 MW
2026		Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW
2027	Plant X 4 - 191 MW Spinning Spur Wind - 161 MW Wildorado Wind - 161 MW			
2028	Maddox 1 - 112 MW			
2029				
2030	National Wind - 0.7 MW Nichols 3 - 246 MW	Solar Generic - 10 MW	Solar Generic - 20 MW	
2031	Jones 1 - 243 MW SunEd 4 Solar - 10 MW SunEd 3 Solar - 10 MW SunEd 2 Solar - 10 MW SunEd 1 Solar - 10 MW SunEd 5 Solar - 10 MW	CT F Generic - 466.6 MW	CT F Generic - 233.3 MW	CT F Generic - 233.3 MW
2032	Tolk 1 - 532 MW Tolk 2 - 537 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2033	Hobbs CC - 604 MW MesaLands Wind - 1.48 MW	CT F Generic - 466.6 MW Solar Generic - 20 MW	CT F Generic - 466.6 MW Solar Generic - 60 MW Battery Generic - 60 MW	CT F Generic - 466.6 MW Battery Generic - 60 MW

Scenario Expansion Plan - Financial Load / Carbon

		Alternative Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW / $8 Carbon	Alternative Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW / $20 Carbon	Alternative Resource Portfolio (Base Gas / Financial Load Forecast / $400/kW / $40 Carbon
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2034	Jones 2 - 243 MW Quay County - 23 MW Mammoth Wind - 200 MW PaloDuro Wind - 250 MW	Solar Generic - 760 MW	CT F Generic - 466.6 MW Solar Generic - 250 MW	Solar Generic - 140 MW Battery Generic - 200 MW
2035	Roosevelt Wind - 250 MW	CT F Generic - 466.6 MW	Solar Generic - 180 MW	CT F Generic - 233.3 MW Solar Generic - 70 MW
2036	Harrington 1 - Gas - 340 MW		Solar Generic - 10 MW	CT F Generic - 233.3 MW Solar Generic - 90 MW
2037		CT F Generic - 233.3 MW	CT F Generic - 233.3 MW Solar Generic - 160 MW	Solar Generic - 90 MW
2038	Harrington 2 - Gas - 355 MW	Solar Generic - 10 MW		
2039		CT F Generic - 233.3 MW Solar Generic - 70 MW Battery Generic - 50 MW	CT F Generic - 466.6 MW Solar Generic - 60 MW Battery Generic - 10 MW	CT F Generic - 466.6 MW Solar Generic - 100 MW
2040	Harrington 3 - Gas - 355 MW Cunningham 3 - 106 MW Cunningham 4 - 101 MW	Solar Generic - 50 MW Battery Generic - 10 MW	Solar Generic - 80 MW	Solar Generic - 10 MW Battery Generic - 20 MW
2041	Rosewell Solar - 70 MW Chaves County Solar - 70 MW	CT F Generic - 466.6 MW Solar Generic - 240 MW Battery Generic - 60 MW	CT F Generic - 466.6 MW Solar Generic - 90 MW Battery Generic - 20 MW	CT F Generic - 466.6 MW Solar Generic - 60 MW Battery Generic - 50 MW

Scenario Expansion Plan - Low Load / Carbon

		Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW / $8 Carbon	Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW / $20 Carbon	Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW / $40 Carbon
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2022	Plant X1 - 39 MW Plant X2 - 70 MW Plant X3 - 0 MW Cunningham 1 - 42 MW Nichols 1 - 112 MW			
2023	Nichols 2 - 111 MW			
2024	BlackHawk 1 - 111.685 MW BlackHawk 2 - 111.685 MW CapRock Wind - 80 MW	Solar RFI S_009c - 40 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW
2025	Cunningham 2 - 183 MW Maddox 2 - 69 MW Maddox 3 - 0 MW San Juan Wind - 120 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW	Wind RFI W_002b - 1000 MW Solar RFI S_001a - 385 MW
2026		Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW
2027	Plant X 4 - 191 MW Spinning Spur Wind - 161 MW Wildorado Wind - 161 MW			
2028	Maddox 1 - 112 MW			
2029				
2030	National Wind - 0.7 MW Nichols 3 - 246 MW			Solar Generic - 30 MW
2031	Jones 1 - 243 MW SunEd 4 Solar - 10 MW SunEd 3 Solar - 10 MW SunEd 2 Solar - 10 MW SunEd 1 Solar - 10 MW SunEd 5 Solar - 10 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 110 MW	CT F Generic - 233.3 MW Battery Generic - 20 MW

Scenario Expansion Plan - Low Load / Carbon

		Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW / $8 Carbon	Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW / $20 Carbon	Alternative Resource Portfolio (Base Gas / Low Load Forecast / $400/kW / $40 Carbon
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2032	Tolk 1 - 532 MW Tolk 2 - 537 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW
2033	Hobbs CC - 604 MW MesaLands Wind - 1.48 MW	CT F Generic - 466.6 MW Solar Generic - 360 MW Battery Generic - 110 MW	CT F Generic - 466.6 MW Battery Generic - 10 MW	CT F Generic - 466.6 MW Battery Generic - 120 MW
2034	Jones 2 - 243 MW Quay County - 23 MW Mammoth Wind - 200 MW PaloDuro Wind - 250 MW	CT F Generic - 233.3 MW Solar Generic - 760 MW	Solar Generic - 660 MW	CT F Generic - 233.3 MW Solar Generic - 280 MW
2035	Roosevelt Wind - 250 MW	CT F Generic - 233.3 MW Solar Generic - 180 MW	CT F Generic - 466.6 MW	CT F Generic - 233.3 MW Solar Generic - 160 MW
2036	Harrington 1 - Gas - 340 MW	Solar Generic - 140 MW		Solar Generic - 10 MW
2037		CT F Generic - 233.3 MW	CT F Generic - 233.3 MW	CT F Generic - 233.3 MW Solar Generic - 110 MW
2038	Harrington 2 - Gas - 355 MW			
2039		CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 30 MW
2040	Harrington 3 - Gas - 355 MW Cunningham 3 - 106 MW Cunningham 4 - 101 MW	Solar Generic - 60 MW	Solar Generic - 30 MW	Solar Generic - 60 MW
2041	Rosewell Solar - 70 MW Chaves County Solar - 70 MW	CT F Generic - 466.6 MW Solar Generic - 200 MW Battery Generic - 30 MW	CT F Generic - 466.6 MW Solar Generic - 220 MW Battery Generic - 30 MW	CT F Generic - 466.6 MW Solar Generic - 80 MW Battery Generic - 30 MW

Scenario Expansion Plan - Planning Load / Carbon

		Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW / $8 Carbon	Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW / $20 Carbon	Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW / $40 Carbon
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2022	Plant X1 - 39 MW Plant X2 - 70 MW Plant X3 - 0 MW Cunningham 1 - 42 MW Nichols 1 - 112 MW			
2023	Nichols 2 - 111 MW			
2024	BlackHawk 1 - 111.685 MW BlackHawk 2 - 111.685 MW CapRock Wind - 80 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_005a - 250 MW Wind RFI W_006a - 150 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Wind RFI W_003d - 300 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_005a - 250 MW Wind RFI W_006a - 150 MW	Solar RFI S_009c - 40 MW Solar (Solar + Battery RFI) S_004e - 500 MW Battery (Solar + Battery RFI) SB_003e-BTM/SYS - 200 MW Solar (Solar + Battery RFI) S_002d - 250 MW Battery (Solar + Battery RFI) SB_001d-BTM/SYS - 125 MW Wind RFI W_003d - 300 MW Wind RFI W_004d - 509 MW Wind (Wind + Battery RFI) WB_001a - 129 MW Battery (Wind + Battery RFI) WB_001a-SYS - 20 MW Wind RFI W_005a - 250 MW Wind RFI W_006a - 150 MW
2025	Cunningham 2 - 183 MW Maddox 2 - 69 MW Maddox 3 - 0 MW San Juan Wind - 120 MW	Wind RFI W_002b - 1000 MW Solar RFI S_007a - 500 MW	Wind RFI W_002b - 1000 MW Solar RFI S_001a - 385 MW Solar RFI S_007a - 500 MW	Wind RFI W_002b - 1000 MW Solar RFI S_001a - 385 MW Solar RFI S_007a - 500 MW
2026		Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW	Wind RFI W_001k - 500 MW
2027	Plant X 4 - 191 MW Spinning Spur Wind - 161 MW Wildorado Wind - 161 MW			
2028	Maddox 1 - 112 MW			
2029		CT F Generic - 233.3 MW		
2030	National Wind - 0.7 MW Nichols 3 - 246 MW	CT F Generic - 233.3 MW	CT F Generic - 233.3 MW Solar Generic - 20 MW	Solar Generic - 250 MW

Scenario Expansion Plan - Planning Load / Carbon

		Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW / $8 Carbon	Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW / $20 Carbon	Alternative Resource Portfolio (Base Gas / Planning Load Forecast / $400/kW / $40 Carbon
Year	**Retirements**	**Expansion Plan**	**Expansion Plan**	**Expansion Plan**
2031	Jones 1 - 243 MW SunEd 4 Solar - 10 MW SunEd 3 Solar - 10 MW SunEd 2 Solar - 10 MW SunEd 1 Solar - 10 MW SunEd 5 Solar - 10 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 10 MW
2032	Tolk 1 - 532 MW Tolk 2 - 537 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 80 MW
2033	Hobbs CC - 604 MW MesaLands Wind - 1.48 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 150 MW Battery Generic - 150 MW	CT F Generic - 466.6 MW Solar Generic - 70 MW Battery Generic - 300 MW
2034	Jones 2 - 243 MW Quay County - 23 MW Mammoth Wind - 200 MW PaloDuro Wind - 250 MW	CT F Generic - 233.3 MW Solar Generic - 540 MW	CT F Generic - 233.3 MW Solar Generic - 120 MW	CT F Generic - 233.3 MW Solar Generic - 300 MW
2035	Roosevelt Wind - 250 MW	CT F Generic - 466.6 MW	CT F Generic - 466.6 MW Solar Generic - 20 MW	CT F Generic - 466.6 MW
2036	Harrington 1 - Gas - 340 MW	Solar Generic - 130 MW	Solar Generic - 110 MW	Solar Generic - 220 MW
2037		CT F Generic - 233.3 MW Solar Generic - 20 MW	CT F Generic - 233.3 MW Solar Generic - 140 MW	Solar Generic - 160 MW Battery Generic - 20 MW
2038	Harrington 2 - Gas - 355 MW	Solar Generic - 30 MW	Solar Generic - 140 MW	CT F Generic - 233.3 MW Solar Generic - 60 MW Battery Generic - 20 MW
2039		CT F Generic - 466.6 MW Solar Generic - 130 MW	CT F Generic - 466.6 MW Solar Generic - 150 MW	CT F Generic - 466.6 MW Solar Generic - 100 MW
2040	Harrington 3 - Gas - 355 MW Cunningham 3 - 106 MW Cunningham 4 - 101 MW	Solar Generic - 90 MW	Solar Generic - 120 MW	Solar Generic - 90 MW
2041	Rosewell Solar - 70 MW Chaves County Solar - 70 MW	CT F Generic - 466.6 MW Solar Generic - 150 MW Battery Generic - 120 MW	CT F Generic - 466.6 MW Solar Generic - 30 MW Battery Generic - 80 MW	CT F Generic - 466.6 MW Solar Generic - 120 MW Battery Generic - 120 MW

Existing and Anticipated Environmental Laws and Regulations

This appendix summarizes the current status and remaining unknowns about each environmental regulation, 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, were repealed and replaced under the Trump administration with the Affordable Clean Energy ("ACE") rule. Subsequently, the ACE rule was vacated by the U.S. Court of Appeals for the D.C. Circuit in a January 19, 2021 decision. This decision, as modified by a subsequent clarification by the court, would have the effect of invalidating the ACE rule and allowing the Environmental Protection Agency ("EPA") to proceed with a new approach to regulating Green House Gas ("GHG") emissions from the power sector. At this point, the timing or nature of any such rules is unclear. The significant uncertainty in Federal climate policy 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), 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.

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. The following table shows Texas' and New Mexico's status under the current NAAQS in areas where SPS operates power plants:

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 was then monitored to gather additional data to support a further attainment/nonattainment decision. If the area near the Harrington Plant had been designated nonattainment, the Texas Commission on Environmental Quality ("TCEQ") would have developed a SIP, which would have been due by 2022, designed to achieve the SO_2 NAAQS by early 2026. The TCEQ could have required additional SO_2 controls at Harrington as part of such a plan.

The monitoring completed in 2020 showed an exceedance of the SO_2 NAAQS in the area of the Harrington Plant. Rather than proceed with a nonattainment designation, SPS negotiated an order with the TCEQ providing for the end of coal combustion and the conversion of the Harrington plant to a natural gas fueled facility by Jan. 1, 2025. This will allow the area to meet the SO_2 NAAQS. The area will remain designated as unclassifiable in the interim.

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.[1] 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.

---

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

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 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 (for particles) under CSAPR. Texas remains subject to the summertime NOx emission budgets under the CSAPR ozone program.

There has been considerable judicial and regulatory activity since that time, but it appears that for the existing ozone standards, Texas (and therefore SPS) is unlikely to face additional NOx restrictions. Thus, SPS currently forecasts compliance with the 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 did 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 was being held in abeyance pending EPA's decision whether to administratively reconsider the rule.[2] EPA has now completed its reconsideration and, in September 2020 issued a final rule approving a Texas SO_2 trading program consistent with the 2017 rule (with minor modifications). SPS expects to be able to meet the allowance allocations of the rule.

---

[2] Several parties 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.

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 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 EPA has not announced a schedule for acting on the remanded rule, but the issue has not formally been resolved. As indicated below, neither Tolk nor Harrington are proposed by Texas for additional controls in the next round of regional haze planning, but those plans also will be subject to review by EPA. This issue may get rolled into the next review. 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. At this point, although it could still change with EPA review (as noted above), the states of Texas and New Mexico are not currently proposing any additional regulation of SPS sources in this next planning cycle. 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").[3] The rule, as subsequently modified by litigation and rule amendment, 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, 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

---

[3] *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.

aquatic species. The regulations must address both impingement (the trapping of aquatic biota 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 October 2020, EPA revised the ELG rule for certain waste streams and postponed compliance requirements for units retiring by 2028. SPS facilities are not subject to the ELG rule because they do not discharge to surface waters.

Xcel Energy®
RESPONSIBLE BY NATURE®

790 S. Buchanan St.
Amarillo, TX 79101

April 8, 2020

Ms. Melanie Sandoval
New Mexico Public Regulation Commission
1120 Paseo De Peralta
Santa Fe, NM 87501

RE: Southwestern Public Service Company ("SPS") Integrated Resource Plan ("IRP") – Public Advisory Invitation

Dear Ms. Sandoval:

In compliance with the requirements of 17.7.3 NMAC (Integrated Resource Plans for Electric Utilities), and more specifically section 17.7.3.9(H) NMAC (Public Advisory Process) of that rule, SPS invites the Commission, intervenors in its most recent general electric rate case, parties in its most recent electric energy efficiency and renewable energy cases, and its customers to participate in SPS's IRP Public Advisory Process. The purpose of the Public Advisory Process in this matter is to provide information to, and receive and consider input from, the public regarding the development of SPS's IRP. Topics for the IRP include the load forecast; evaluation of existing supply- and demand-side resources; assessment of need for additional resources; identification of resource options; modeling; and development of the most cost-effective resource portfolio for the IRP. SPS is also providing notice to its customers in their bills and publishing a similar invitation in the newspapers of general circulation in every county that SPS serves in New Mexico. . The first of a series of workshops will be held May 21, 2020 from 1:30 p.m. to 4 p.m. MT in the 5th floor CYFD conference room 565 of the New Mexico Public Regulation Commission offices in the P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, NM.

> Attendance via WEBINAR is also available with the following login information:
> Call in number: 1-866-672-3839 Passcode: 6877906
> https://avayaconference.xcelenergy.com/6877906

If an in-person meeting is not possible on May 21 due to Coronavirus concerns, SPS plans to proceed with a WEBINAR-only meeting.

SPS will provide the date and time of each subsequent workshop at the conclusion of the prior workshop. Any person interested in participating in SPS's IRP Public Advisory Process should contact us at 1-806-378-2709, 1-806-378-2115, Linda.L.Hudgins@xcelenergy.com, or Mario.A.Contreras@xcelenergy.com. A similar notice, information about future workshops, and other information can be found under "Rates & Regulations"at **www.xcelenergy.com**. SPS will file its IRP at the New Mexico Public Regulation Commission by July 16, 2021.

Please do not hesitate to contact me with any questions you may have regarding this invitation or the pending meeting.

Sincerely,

/S/ Mario Contreras
Mario Contreras
Rate Case Manager
Southwestern Public Service Company

cc: Certificate of Service – Combined lists of NMPRC Case No. 19-00170-UT (Rate Case), 19-00140-UT (Energy Efficiency), 19-00134-UT (Renewable Portfolio Standard) and 18-00215-UT (IRP)

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

**IN THE MATTER OF SOUTHWESTERN)
PUBLIC SERVICE COMPANY'S)
2021 INTEGRATED RESOURCE PLAN)
FOR NEW MEXICO,)
)
SOUTHWESTERN PUBLIC SERVICE)
COMPANY,)
)
APPLICANT.)
)**

CERTIFICATE OF SERVICE

I certify that a true and correct copy of *Southwestern Public Service Company's 2021 Integrated Resource Plan – Public Advisory Invitation* was electronically served, as indicated below, to each of the following on this 8th day of April, 2020:

VIA E-MAIL:

Will DuBois, Esq.	will.w.dubois@xcelenergy.com	Dana S. Hardy, Esq.	dhardy@hinklelawfirm.com
Mario A. Contreras	mario.a.contreras@xcelenergy.com	Jack Sidler	Jack.Sidler@state.nm.us
William A. Grant	william.a.grant@xcelenergy.com	Stephanie Dzur	Stephanie@Dzur-Law.com
Phillip Oldham	phillip.oldham@tklaw.com	Jeffry Pollock	jcp@jpollockinc.com
Katherine Coleman	katie.coleman@tklaw.com	Joshua Smith	joshua.smith@sierraclub.org
Melissa Trevino	melissa_trevino@oxy.com	Nikolas Stoffel	nsstoffel@hollandhart.com
Joan E. Drake	jdrake@modrall.com	Thorvald A. Nelson	tnelson@hollandhart.com
Andrea Crane	ctcolumbia@aol.com	Austin Rueschhoff	darueschhoff@hollandhart.com
Michael P. Gorman	mgorman@consultbai.com	Maj. Scott Kirk	Scott.kirk.2@us.af.mil
Doug Gegax	dgegax@nmsu.edu	Pat O'Connell	Pat.oconnell@westernresources.org
Linda Hudgins	Linda.l.hudgins@xcelenergy.com	Ben Phillips, Esq	ben.phillips@pnmresources.com
Evan D. Evans	Evan.d.evans@xcelenergy.com	David Van Winkle	david@vw77.com
John Degnan	John.degnan@us.af.mil	Amy Shelhamer	ashelhamer@courtneylawfirm.com
Sonya Mares	smares@hinklelawfirm.com	Sally Wilhelms	swilhelms@consultbai.com
Ron H. Moss	rhmoss@winstead.com	Sarah Gersen	sgersen@eathjustice.org
G. Meyer	gmeyer@consultbai.com	Megan A. O'Reilly	arcresearchandanalysis@gmail.com
Randall Childress	randy@childresslaw.com	Toribio Garcia	Toribio.garcia@us.af.mil
Zoe E. Lees	Zoe.E.Lees@xcelenergy.com	Thomas M. Domme	Tdomme@tecoenergy.com
Randall Woolridge	jrwoolridge@gmail	Rick Gilliam	rick@votesolar.org
Adam Bickford	abickford@swenergy.org	Susan Brymer	Susan.l.brymer@xcelenergy.com
Glenda Murphy	gmurphy@westernresources.org	Ruth Sakya	Ruth.sakya@xcelenergy.com
David G Pitts	davidgpitts@gmail.com	Jeff Comer	Jeffrey.l.comer@xcelenergy.com
Jill Tauber	jtauber@earthjustice.org	Nann M. Winter, Esq	nwinter@stelznerlaw.com
Anthony J. Trujillo	ajt@gknet.com	Anthony Sisneros	Anthony.sisneros@state.nm.us
T.K. E-service	Tk.eservice@tklaw.com	Mark A. Walker	Mark.a.walker@xcelenergy.com
Luke Tougas	l.tougas@cleanenergyresearch.com	Jason Marks	lawoffice@jasonmarks.com
Elaine Heltman	eheltman@nmag.gov	TK Law Office	Tk.eservice@tklaw.com
Don Hancock	sricdon@earthlink.com	Barbara Hart-Hope	bhart@hollandhart.com
Ramona Blaber	ramona.blaber@sierraclub.org	Amanda Alderson	aalderson@consultbai.com
Ebony Payton	ebony.payton.ctr@us.af.mil	Perry Robinson	perry.robinson@urenco.com

Jeff Wernert	jwernert@theprimegroupllc.com	Brian J. Haverly, Esq.	bjh@keleher-law.com
Chuck Pinson	cpinson@cvecoop.org	Nicole V. Strauser, Esq.	nvstrauser@tecoenergy.com
Carla R. Najjar	csnajjar@virtuelaw.com	Rebecca A. Carter	Rebecca.carter@nmgco.com
Steve Seelye	sseelye@theprimegroupllc.com	Antonio Sanchez Jr.	sancheza@rcec.coop
Adele Lee	ACLee@hollandhart.com	Steven Cordova	Steven.cordova@nmgco.com
Matthew Dunne	Mdunne337@gmail.com	Matthew Miller	Matthew.miller@sierraclub.org
Maureen Reno	Mreno@reno-energy.com	April Elliot	April.elliott@westernresources.org
Julianna Hopper	jth@keleher-law.com	Robert L. Friedman	Robert.friedman.5@us.af.mil
Holland Hart	glgarganoamari@hollandhart.com	Arnold Braxton	Arnold.braxton@us.af.mil
Michael McMillin	michael.mcmillin@tklaw.com	Judith Amer	judith.amer@state.nm.us
Cholla Khoury	ckhoury@nmag.gov	Charles F. Noble	noble.ccae@gmail.com
Robert F. Lundin	rlundin@nmag.gov	Bradford Borman	Bradford.Borman@state.nm.us
Gideon Elliot	gelliot@nmag.gov	John Reynolds	John.reynolds@state.nm.us
Michael J. Moffett	mmoffett@cmtisantafe.com	William P. Templeman	wtempleman@cmtisantafe.com
Elisha Leyba-Tercero	elisha.lebya-tercero@state.nm.us	Thomas Jernigan	Thomas.jernigan.3@us.af.mil
Milo Chavez	milo.chavez@state.nm.us	Daniel A. Najjar	dnajjar@virtuelaw.com
Steven S. Michel	smichel@westernresources.org	Julia Broggi	jbroggi@hollandhart.com
John Bogtko	john.bogatko@state.nm.us	Marc Tupler	Marc.Tupler@state.nm.us
Gabriella Dasheno	gabriella.dasheno@state.nm.us	Lauren Hogrewe	lauren.hogrewe@sierraclub.org
Kellie Barahona	kellie.barahona@tklaw.com	Matthew Marchant	matthew.marchant@hollyfrontier.com
Peter Gould	pgouldlaw@gmail.com	Katelyn Hart	khart@redskylawnm.com
John Caldwell	jcaldwell@leacounty.net	Randy Bartell	rbartell@montand.com
Casey Settles	Casey.settles@xcelenergy.com	John Wolfram	johnwolf@catalystell.com

Respectfully submitted,

___/S/ Casey Settles______________________
Casey Settles
790 S. Buchanan Street
Amarillo, TX 79101
806.378.2424
Casey.settles@xcelenergy.com

Xcel Energy®
RESPONSIBLE BY NATURE®

SOUTHWESTERN PUBLIC SERVICE COMPANY

Page 1 of 4

SERVICE ADDRESS	ACCOUNT NUMBER		DUE DATE
[redacted] HOBBS, NM 88242-0814	[redacted]		04/22/2020
	STATEMENT NUMBER	STATEMENT DATE	AMOUNT DUE
	[redacted]	04/02/2020	$167.37

YOUR MONTHLY ELECTRICITY USAGE

DAILY AVERAGES	Last Year	This Year
Temperature	53° F	58° F
Electricity kWh	76.9	56.9

SUMMARY OF CURRENT CHARGES (detailed charges begin on page 2)

Electricity Service	03/04/20 - 04/02/20	1650 kWh	$133.70
Other Recurring Charges			$33.67
Current Charges			**$167.37**

ACCOUNT BALANCE *(Balance de su cuenta)*

Previous Balance	As of 03/04	$527.13
Payment Received	Phone Pay 03/13	-$527.13 **CR**
Balance Forward		**$0.00**
Current Charges		$167.37
Amount Due *(Cantidad a pagar)*		**$167.37**

008316 1/2

QUESTIONS ABOUT YOUR BILL?

See our website:	xcelenergy.com
Email us at:	Customerservice@xcelenergy.com

Call Mon - Fri 7 a.m.-7 p.m. or Sat 9 a.m.-5 p.m.

Please Call:	1-800-895-4999
Hearing Impaired:	1-800-895-4949
Español:	1-800-687-8778

Or write us at:
XCEL ENERGY
PO BOX 8
EAU CLAIRE WI 54702-0008

Like us on Facebook Follow us on Twitter

INFORMATION ABOUT YOUR BILL

Your safety and the safety of our employees will always be our top priority. We are prepared and are taking steps to ensure we'll continue to be there for you to meet your energy needs as COVID-19 affects a growing number of people in our communities. We know this is a challenging time for many families, and we are here to help. Please reach out to our customer care representatives if you have questions about your bill, and learn more at xcelenergy.com/covid-19_response.

RETURN BOTTOM PORTION WITH YOUR PAYMENT • **PLEASE DO NOT USE STAPLES, TAPE OR PAPER CLIPS**

Xcel Energy®

ACCOUNT NUMBER	DUE DATE	AMOUNT DUE	AMOUNT ENCLOSED
[redacted]	04/22/2020	$167.37	

11

Please remit to the address below by the Due Date to avoid late payment fees.
Make your check payable to XCEL ENERGY

APRIL						
S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30		

------ manifest line ---------

[redacted]
HOBBS NM 88242-0814

XCEL ENERGY
P.O. BOX 9477
MPLS MN 55484-9477

[redacted]

SERVICE ADDRESS	ACCOUNT NUMBER		DUE DATE
[redacted] HOBBS, NM 88242-0814	[redacted]		04/22/2020
	STATEMENT NUMBER	STATEMENT DATE	AMOUNT DUE
	[redacted]	04/02/2020	**$167.37**

INFORMATION ABOUT YOUR BILL

We invite you to participate in our Electric Service Integrated Resource Planning (IRP) Public Advisory process. IRP examines the types of resources to be included in Xcel Energy's resource portfolio, the amounts that must be added, and the timing of those additions. An IRP provides a strategic outline for future resource decisions by Xcel Energy.

The first of a series of workshops will be held May 21, 2020, from 1:30 p.m. to 4 p.m. MT in the 5th floor Children, Youth & Families Department conference room 565 of the New Mexico Public Regulation Commission offices in the P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, NM. Attendance via webinar is also available: For audio dial 1-866-672-3839 using passcode: 6877906. Follow the presentation online at: https://avayaconference.xcelenergy.com/6877906

Xcel Energy will provide the date and time of each subsequent workshop at the conclusion of the prior workshop.

If you are interested in participating in our IRP Public Advisory process, please contact us at 1-806-378-2709, 1-806-378-2115, Linda.L.Hudgins@xcelenergy.com, or Mario.A.Contreras@xcelenergy.com. This notice, future workshops and other information can be found under Rates & Regulations at www.xcelenergy.com. We will file our IRP at the New Mexico Public Regulation Commission by July 16, 2021.

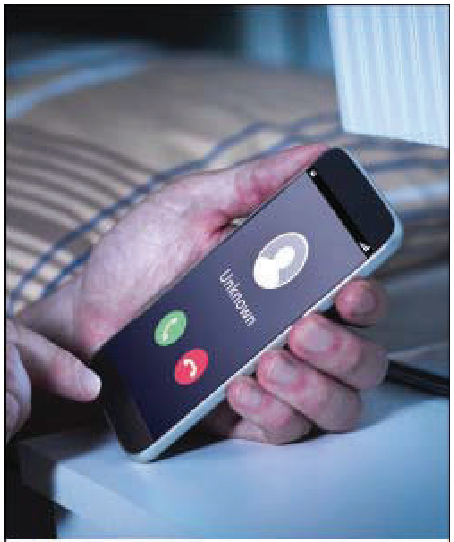
Thank you for your payment.

APPLY THE 10-FOOT RULE.

Power lines are just what they sound like — powerful. When you're cleaning out gutters, stay safe by keeping yourself, ladder and tools at least 10 feet from overhead power lines.

Xcel Energy®

SERVICE ADDRESS	ACCOUNT NUMBER		DUE DATE
[redacted] [redacted] [redacted]	[redacted]		04/22/2020
	STATEMENT NUMBER	STATEMENT DATE	AMOUNT DUE
	[redacted]	04/02/2020	$167.37



SERVICE ADDRESS: [redacted]
NEXT READ DATE: 05/04/20

ELECTRICITY SERVICE DETAILS

PREMISES NUMBER: [redacted]
INVOICE NUMBER: [redacted]

METER READING INFORMATION

METER [redacted] Read Dates: 03/04/20 - 04/02/20 (29 Days)

DESCRIPTION	CURRENT READING	PREVIOUS READING	USAGE
Total Energy	89884 Actual	88234 Actual	1650 kWh

ELECTRICITY CHARGES RATE: RHS Res Htg Svc

DESCRIPTION	USAGE UNITS	RATE	CHARGE
Svc Availability			$8.75
Res Htg Svc	1650 kWh	$0.048258	$79.63
Fuel Cost Factor	1536.21 kWh	$0.017037	$26.17
Fuel Cost Factor	113.79 kWh	$0.015594	$1.77
Energy Efficiency Rdr			$4.00
RPS Cost Rider	1650 kWh	$0.003888	$6.42
Subtotal			**$126.74**
Sales Tax			$6.96
Total			**$133.70**

OTHER RECURRING CHARGES DETAILS

INVOICE NUMBER: [redacted]
ADDRESS: [redacted]
HOBBS, NM 88242-0814

DESCRIPTION	USAGE UNITS	UNIT CHARGE	QTY	CHARGE
Install Number [redacted]				
03/04/20 to 04/01/20				
1000 WATT HPS - RAL				
Area Light	328 kWh	$24.04	1	$24.04
Fuel Cost Factor				$5.58
RPS Cost Rider				$1.28
Energy Efficiency Rdr				$1.02
Subtotal				**$31.92**
Sales Tax				$1.75
Total				**$33.67**

INFORMATION ABOUT YOUR BILL

This month, an additional kWh used would have cost 7.57 ¢/kWh.

6B | WEDNESDAY, APRIL 8, 2020 | CARLSBAD CURRENT-ARGUS

Legal Notices

Legal Notices

Southwestern Public Service Company ("SPS") invites the public to participate in its electric service Integrated Resource Planning ("IRP") Public Advisory Process. An IRP examines the types of resources to be included in the utility's resource portfolio, the amounts that must be added, and the timing for those additions. In effect, an IRP provides a strategic plan for future resource decisions by the utility.

The purpose of SPS's Public Advisory Process is to provide information to, and receive and consider input from the public regarding the development of the IRP. Topics for the IRP include the load forecast; evaluation of existing supply- and demand-side resources; assessment of need for additional resources; identification of resource options; modeling; and development of the most cost-effective resource portfolio for the IRP. The first of a series of workshops will be held May 21, 2020 from 1:30 p.m. to 4 p.m. MT in the 5th floor CYFD conference room 565 of the New Mexico Public Regulation Commission offices in the P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, NM.

Attendance via WEBINAR is also available with the following login information:

Call in number: 1-866-672-3839 Passcode: 6877906
https://avayaconference.xcelenergy.com/6877906

If an in-person meeting is not possible on May 21 due to Coronavirus concerns, SPS plans to proceed with a WEBINAR-only meeting.

SPS will provide the date and time of each subsequent workshop at the conclusion of the prior workshop.

Any person interested in participating in SPS's Electric IRP Public Advisory Process should contact SPS at 1-806-378-2709, 1-806-378-2115, Linda.L.Hudgins@xcelenergy.com, or Mario.A.Contreras@xcelenergy.com. This notice, information about future workshops, and other information can be found under "Rates & Regulations" at www.xcelenergy.com . SPS will file its IRP at the New Mexico Public Regulation Commission by July 16, 2021.

April 8, 2020

AFFIDAVIT OF LEGAL PUBLICATION

Legal 8618

STATE OF NEW MEXICO
COUNTIES OF CURRY
AND ROOSEVELT:
The undersigned, being dully sworn, says:
That she is a Legal Clerk of
The Eastern New Mexico News
Newspaper of general circulation,
Published in English at Clovis and Portales,
said counties and state, and that the
hereto attached

2021 New Mexico IRP
Legal 8618

was published in The Eastern New Mexico News a daily newspaper duly qualified for that purpose within the meaning of Chapter 167 of the 1937 Session Laws of the State of New Mexico for 1 Days/weeks on the same days as follows:

First Publication April 8, 2020
Second Publication
Third Publication
Fourth Publication

Tammy Newby
Legal Clerk

Subscribed and sworn to before me,
April 8, 2020

Cindy L. Cole
Notary Public

My commission expires on April 3, 2022

Official Seal
CINDY L. COLE
Notary Public
State of New Mexico
My Comm. Expires 4/3/22

Legal 8618
April 8, 2020

SOUTHWESTERN PUBLIC SERVICE Company ("SPS") invites the public to participate in its electric service Integrated Resource Planning ("IRP") Public Advisory Process. An IRP examines the types of resources to be included in the utility's resource portfolio, the amounts that must be added, and the timing for those additions. In effect, an IRP provides a strategic plan for future resource decisions by the utility.

The purpose of SPS's Public Advisory Process is to provide information to, and receive and consider input from the public regarding the development of the IRP. Topics for the IRP include the load forecast; evaluation of existing supply- and demand-side resources; assessment of need for additional resources; identification of resource options; modeling; and development of the most cost-effective resource portfolio for the IRP. The first of a series of workshops will be held May 21, 2020 from 1:30 p.m. to 4 p.m. MT in the 5th floor CYFD conference room 565 of the New Mexico Public Regulation Commission offices in the P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, NM.

Attendance via WEBINAR is also available with the following login information:
Call in number: 1-866-672-3839 Passcode: 6877906
https://avayaconference.xcelenergy.com/6877906

If an in-person meeting is not possible on May 21 due to Coronavirus concerns, SPS plans to proceed with a WEBINAR-only meeting.

SPS will provide the date and time of each subsequent workshop at the conclusion of the prior workshop.

Any person interested in participating in SPS's Electric IRP Public Advisory Process should contact SPS at 1-806-378-2709, 1-806-378-2115, Linda.L.Hudgins@xcelenergy.com, or Mario.A.Contreras@xcelenergy.com. This notice, information about future workshops, and other information can be found under "Rates & Regulations" at www.xcelenergy.com. SPS will file its IRP at the New Mexico Public Regulation Commission by July 16, 2021.

AFFIDAVIT OF LEGAL PUBLICATION

Copy of Publication

Legal 8619

STATE OF NEW MEXICO
COUNTIES OF QUAY:

The undersigned, being dully sworn, says:
That she is a Legal Clerk of
The QUAY COUNTY SUN, a weekly
Newspaper of general circulation,
Published in English at Tucumcari,
said county and state, and that the
hereto attached

2021 New Mexico IRP
Legal 8619

was published in The QUAY COUNTY SUN
a weekly newspaper duly qualified
for that purpose within the meaning of Chapter 167
of the 1937 Session Laws of the State of New Mexico
for 1 Days on the same days as follows:

First Publication: April 8, 2020
Second Publication:
Third Publication
Fourth Publication:

Tammy Newby
Legal Clerk

Subscribed and sworn to before me,
April 8, 2020

Cindy L. Cole
Notary Public

My Commission Expires: April 3, 2022

Official Seal
CINDY L. COLE
Notary Public
State of New Mexico
My Comm. Expires 4/3/22

Legal 8619
April 8, 2020

SOUTHWESTERN PUBLIC SERVICE Company ("SPS") invites the public to participate in its electric service Integrated Resource Planning ("IRP") Public Advisory Process. An IRP examines the types of resources to be included in the utility's resource portfolio, the amounts that must be added, and the timing for those additions. In effect, an IRP provides a strategic plan for future resource decisions by the utility.

The purpose of SPS's Public Advisory Process is to provide information to, and receive and consider input from the public regarding the development of the IRP. Topics for the IRP include the load forecast; evaluation of existing supply- and demand-side resources; assessment of need for additional resources; identification of resource options; modeling; and development of the most cost-effective resource portfolio for the IRP. The first of a series of workshops will be held May 21, 2020 from 1:30 p.m. to 4 p.m. MT in the 5th floor CYFD conference room 565 of the New Mexico Public Regulation Commission offices in the P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, NM.

Attendance via WEBINAR is also available with the following login information:
Call in number: 1-866-672-3839 Passcode: 6877906 https://avaya-conference.xcelenergy.com/6877906

If an in-person meeting is not possible on May 21 due to Coronavirus concerns, SPS plans to proceed with a WEBINAR-only meeting.

SPS will provide the date and time of each subsequent workshop at the conclusion of the prior workshop.

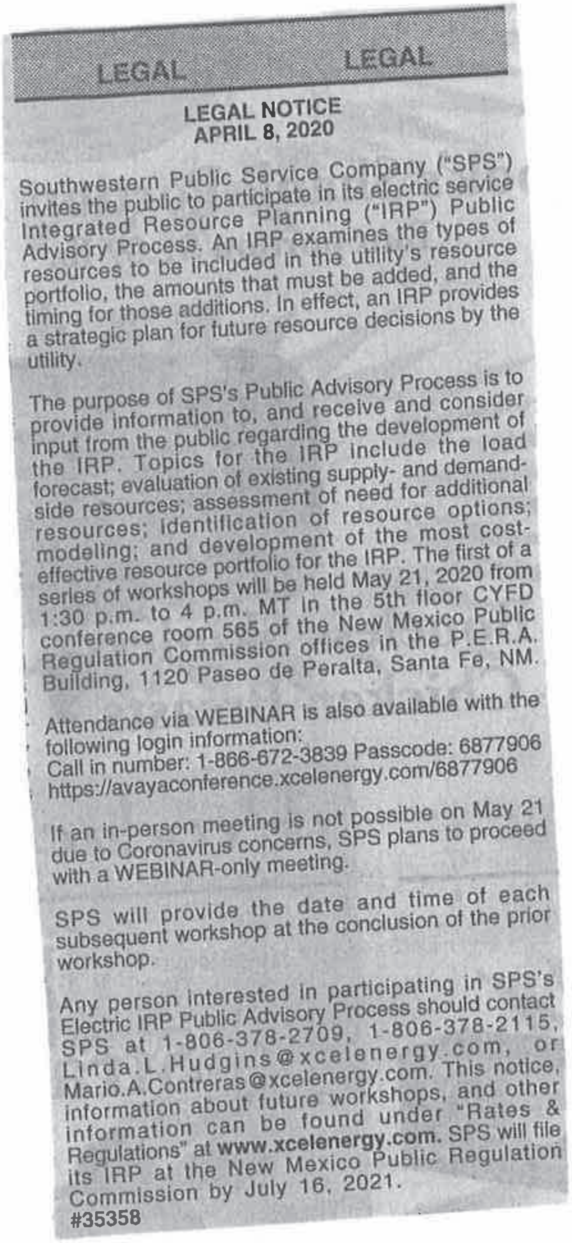
Any person interested in participating in SPS's Electric IRP Public Advisory Process should contact SPS at 1-806-378-2709, 1-806-378-2115, Linda.L.Hudgins@xcelenergy.com, or Mario.A.Contreras@xcelenergy.com. This notice, information about future workshops, and other information can be found under "Rates & Regulations" at www.xcelenergy.com. SPS will file its IRP at the New Mexico Public Regulation Commission by July 16, 2021.

Affidavit of Publication

STATE OF NEW MEXICO
COUNTY OF LEA

I, Daniel Russell, Publisher of the Hobbs News-Sun, a newspaper published at Hobbs, New Mexico, solemnly swear that the clipping attached hereto was published in the regular and entire issue of said newspaper, and not a supplement thereof for a period of 1 issue(s).

Beginning with the issue dated
April 08, 2020
and ending with the issue dated
April 08, 2020.



LEGAL LEGAL

LEGAL NOTICE
APRIL 8, 2020

Southwestern Public Service Company ("SPS") invites the public to participate in its electric service Integrated Resource Planning ("IRP") Public Advisory Process. An IRP examines the types of resources to be included in the utility's resource portfolio, the amounts that must be added, and the timing for those additions. In effect, an IRP provides a strategic plan for future resource decisions by the utility.

The purpose of SPS's Public Advisory Process is to provide information to, and receive and consider input from the public regarding the development of the IRP. Topics for the IRP include the load forecast; evaluation of existing supply- and demand-side resources; assessment of need for additional resources; identification of resource options; modeling; and development of the most cost-effective resource portfolio for the IRP. The first of a series of workshops will be held May 21, 2020 from 1:30 p.m. to 4 p.m. MT in the 5th floor CYFD conference room 565 of the New Mexico Public Regulation Commission offices in the P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, NM.

Attendance via WEBINAR is also available with the following login information:
Call in number: 1-866-672-3839 Passcode: 6877906
https://avayaconference.xcelenergy.com/6877906

If an in-person meeting is not possible on May 21 due to Coronavirus concerns, SPS plans to proceed with a WEBINAR-only meeting.

SPS will provide the date and time of each subsequent workshop at the conclusion of the prior workshop.

Any person interested in participating in SPS's Electric IRP Public Advisory Process should contact SPS at 1-806-378-2709, 1-806-378-2115, Linda.L.Hudgins@xcelenergy.com, or Mario.A.Contreras@xcelenergy.com. This notice, information about future workshops, and other information can be found under "Rates & Regulations" at **www.xcelenergy.com**. SPS will file its IRP at the New Mexico Public Regulation Commission by July 16, 2021.
#35358

Dan Russell
Publisher

Sworn and subscribed to before me this 8th day of April 2020.

Gussie Black
Business Manager

My commission expires
January 29, 2023
(Seal)

OFFICIAL SEAL
GUSSIE BLACK
Notary Public
State of New Mexico
My Commission Expires 1-29-23

This newspaper is duly qualified to publish legal notices or advertisements within the meaning of Section 3, Chapter 167, Laws of 1937 and payment of fees for said

67103518

00241003

Attn: CINDY BAEZA
XCEL ENERGY/AMARILLO
790 S BUCHANAN ST
AMARILLO, TX 79101-2522

AFFIDAVIT OF PUBLICATION
STATE OF NEW MEXICO

I, Noely Martinez
Legals Clerk

Of the Roswell Daily Record, a daily newspaper published at Roswell, New Mexico do solemnly swear that the clipping hereto attached was published in the regular and entire issue of said paper and not in a supplement there of for a period of:

One time with the issue dated
April 8th, 2020

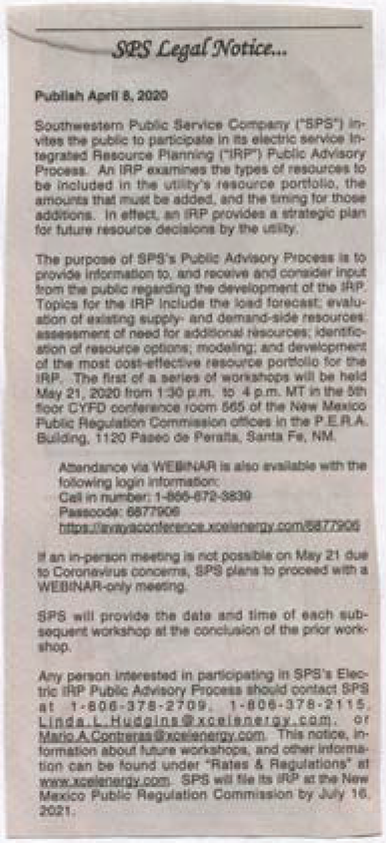
Legals Clerk

Sworn and subscribed to before me

this 12th day of July, 2021

Notary Public

OFFICIAL SEAL
Claudia Martinez
NOTARY PUBLIC - STATE OF NEW MEXICO
My Commission Expires: 4-21-2022



SPS Legal Notice...

Publish April 8, 2020

Southwestern Public Service Company ("SPS") invites the public to participate in its electric service Integrated Resource Planning ("IRP") Public Advisory Process. An IRP examines the types of resources to be included in the utility's resource portfolio, the amounts that must be added, and the timing for those additions. In effect, an IRP provides a strategic plan for future resource decisions by the utility.

The purpose of SPS's Public Advisory Process is to provide information to, and receive and consider input from the public regarding the development of the IRP. Topics for the IRP include the load forecast; evaluation of existing supply- and demand-side resources; assessment of need for additional resources; identification of resource options; modeling; and development of the most cost-effective resource portfolio for the IRP. The first of a series of workshops will be held May 21, 2020 from 1:30 p.m. to 4 p.m. MT in the 5th floor CYFD conference room 565 of the New Mexico Public Regulation Commission offices in the P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, NM.

> Attendance via WEBINAR is also available with the following login information:
> Call in number: 1-866-672-3839
> Passcode: 6877906
> https://avayaconference.xcelenergy.com/6877906

If an in-person meeting is not possible on May 21 due to Coronavirus concerns, SPS plans to proceed with a WEBINAR-only meeting.

SPS will provide the date and time of each subsequent workshop at the conclusion of the prior workshop.

Any person interested in participating in SPS's Electric IRP Public Advisory Process should contact SPS at 1-806-378-2709, 1-806-378-2115, Linda.L.Huggins@xcelenergy.com, or Mario.A.Contreras@xcelenergy.com. This notice, information about future workshops, and other information can be found under "Rates & Regulations" at www.xcelenergy.com. SPS will file its IRP at the New Mexico Public Regulation Commission by July 16, 2021.

Xcel Energy®

2021 SPS New Mexico Integrated Resource Plan: 1st Public Advisory Kick-off Meeting

5/21/2020

Topics for Discussion

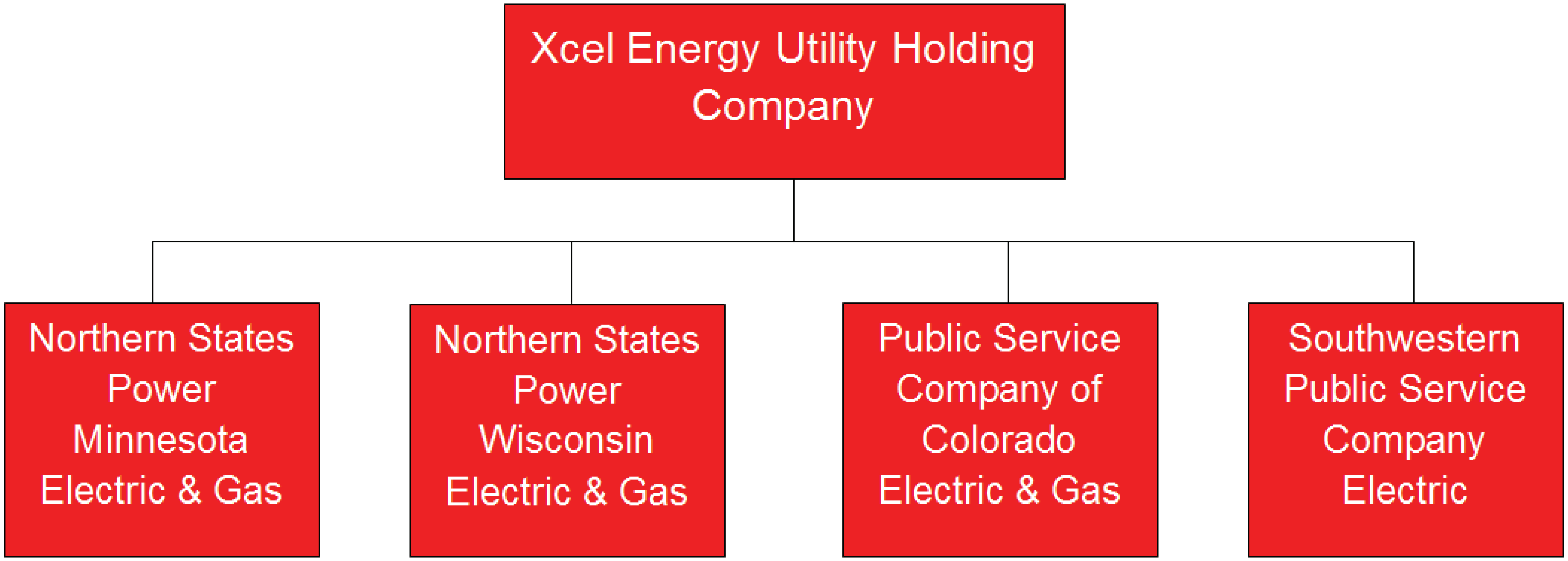
- Xcel Energy and SPS Overview
- Resource Planning Overview
- Factors that have impacted Resource Planning since the 2018 New Mexico IRP
- Factors that will likely influence Resource Planning in the action plan period
- SPS's new renewable wind facilities
- Future meeting topics
- Next meeting

SPS OVERVIEW

Ben Elsey | Resource Planning Analyst

5/21/2020

Corporate Structure



Xcel Energy Utility Holding Company

Northern States Power Minnesota Electric & Gas

Northern States Power Wisconsin Electric & Gas

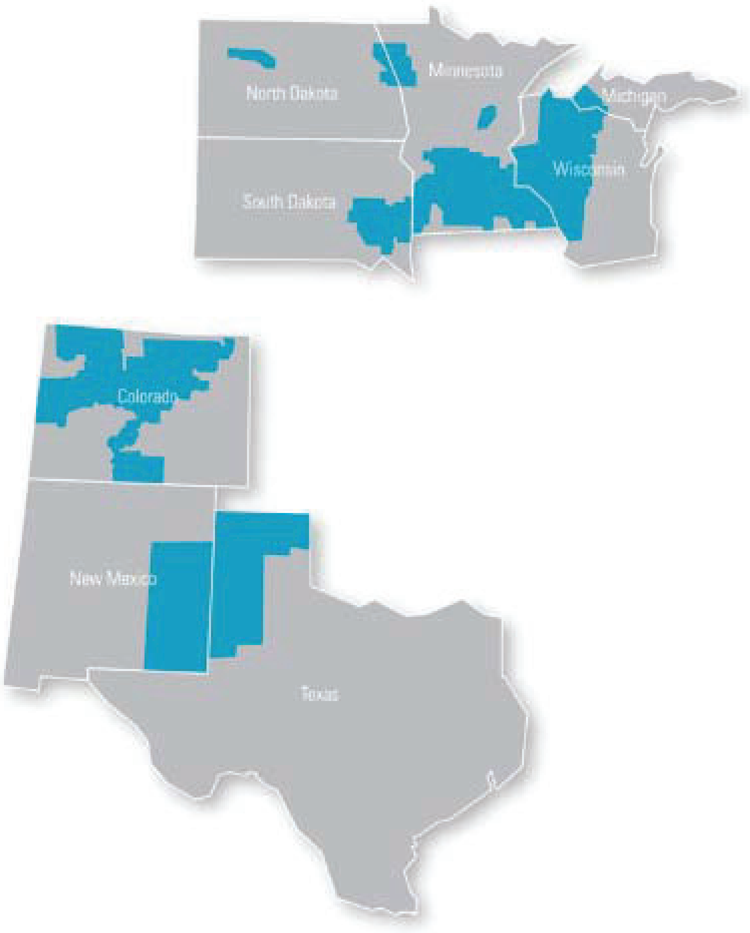
Public Service Company of Colorado Electric & Gas

Southwestern Public Service Company Electric

About Xcel Energy

Serving eight states
- 3.6 million electricity customers
- 2 million natural gas customers

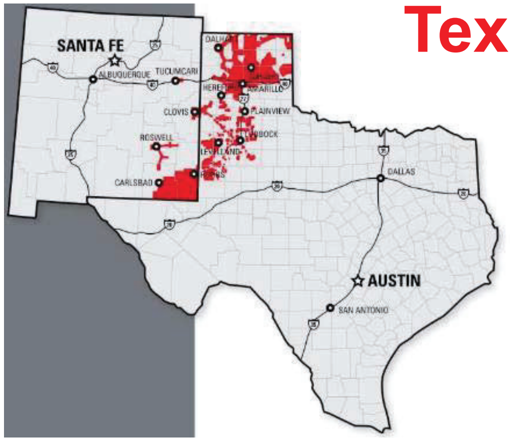
Nationally recognized leader
- Wind energy
- Energy efficiency
- Carbon emissions reductions
- Innovative technology



SPS Overview

- Southwestern Public Service Company (“SPS”) is a New Mexico corporation and wholly-owned electric utility subsidiary of Xcel Energy.
- SPS’s total company service territory encompasses a 52,000-square-mile area in eastern and southeastern New Mexico, the Texas Panhandle, and the Texas South Plains
- SPS’s primary business is generating, transmitting, distributing, and selling electric energy
- SPS has a long history of providing safe, reliable, value-added service to our customers

Texas and New Mexico Retail Customers



- Communities Served
  - 80 in Texas
  - 14 in New Mexico
- 99.9% electric reliability
- Bills below the national average

Texas

271,059 Electric Customers

\+

New Mexico

123,161 Electric Customers

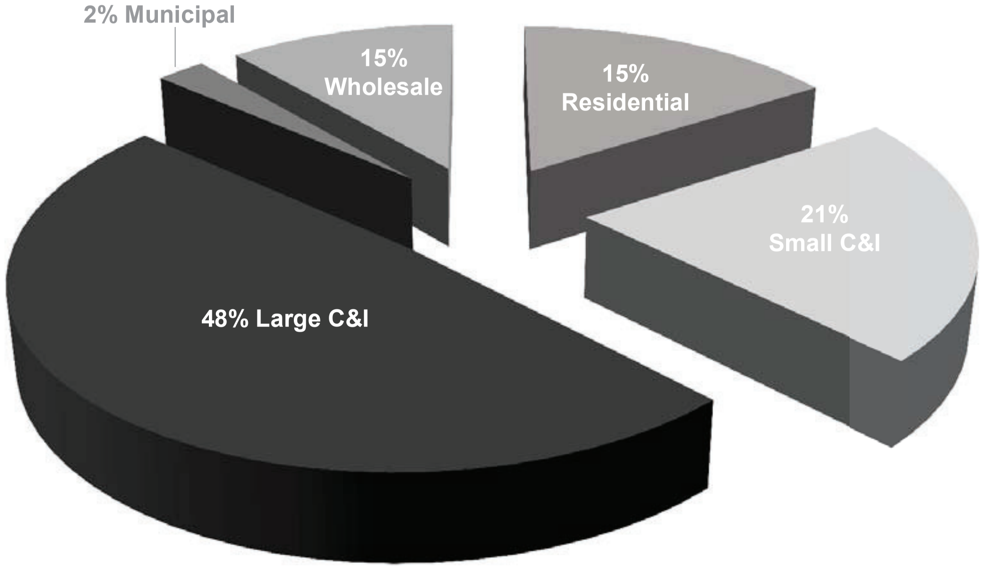
=

Total

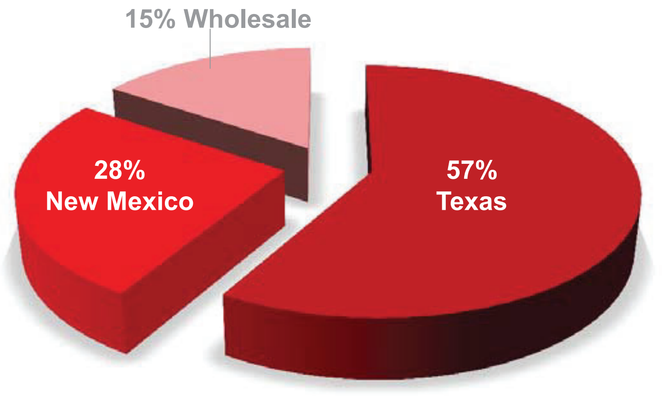
394,220 Electric Customers

SPS Customers

Sales by Class



Jurisdictional Sales Split



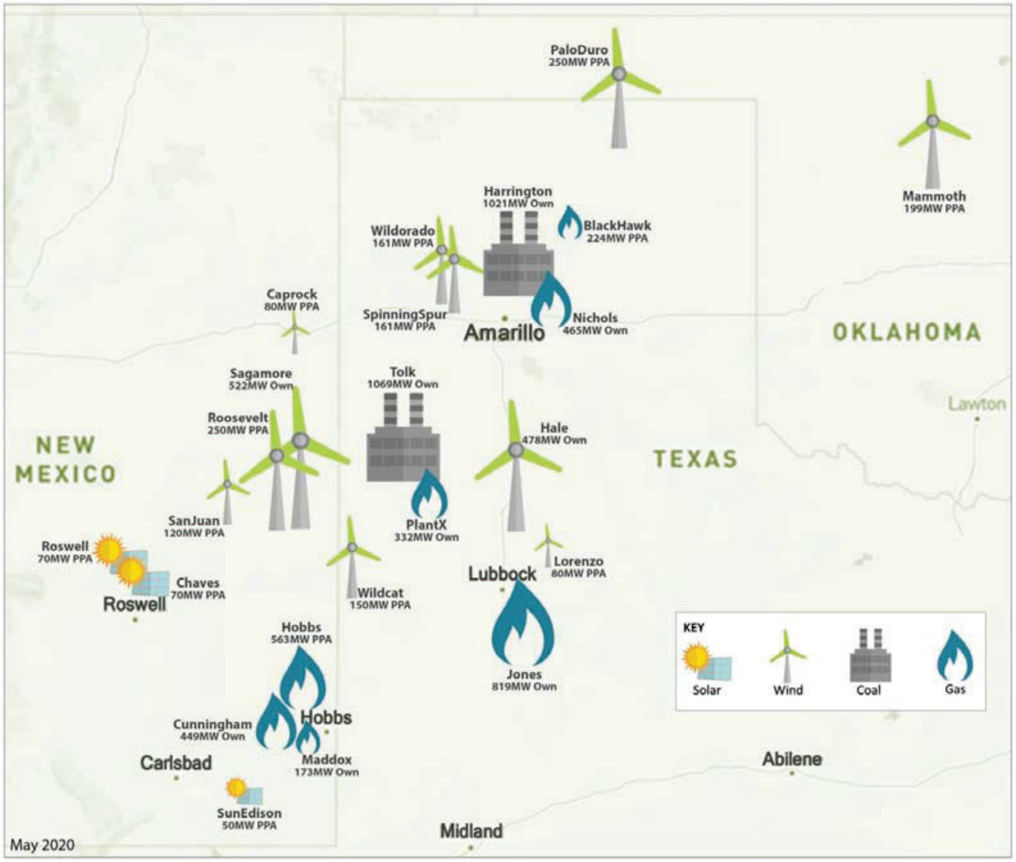
* SPS operates its production and transmission system as an integrated whole

Note: Data as represented is between February 1, 2019 through January 31, 2020

Resource Planning

- Determines the appropriate sources of electric supply to meet customer demand and energy requirements in a cost-effective and reliable fashion
- Compare existing firm generating resources, including owned generating capacity and firm purchased power, to its projected annual peak firm load obligation over the planning period
- Maintains capacity required to meet projected peak load and planning reserve obligations
- SPS is a member of the Southwest Power Pool (“SPP”), which requires each member to have a planning reserve margin of 12% of its peak demand forecast
- SPS’s firm load obligation is approximately 4,000 MW, and with the planning reserve margin the capacity need is approximately 4,500 MW

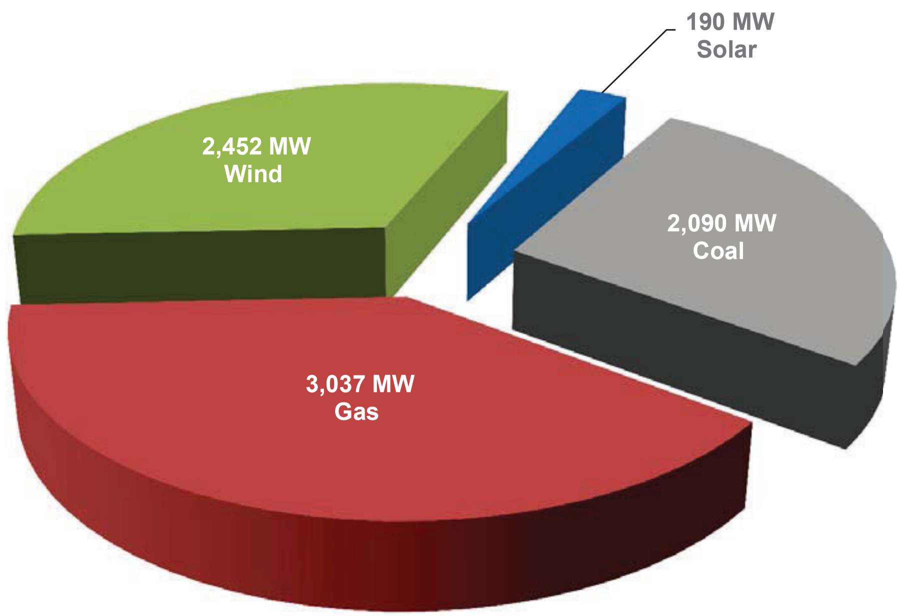
Generation Resource Map



Current SPS Loads and Resources Table

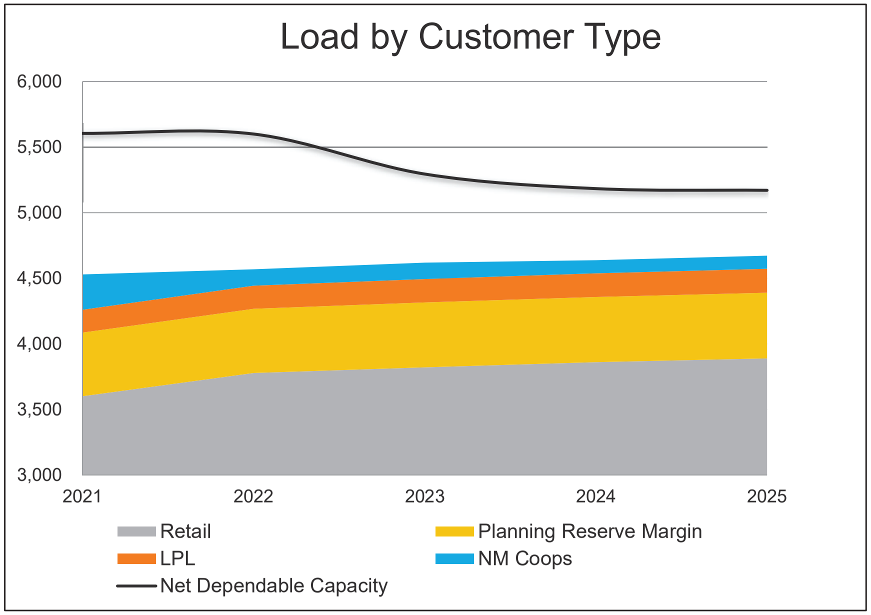
SPS Load and Resources	2020	2021	2022	2023	2024	2025
EXISTING RESOURCES						
TOTAL ACCREDITED CAPACITY (MW)	5,605	5,605	5,600	5,295	5,184	5,171
LOAD						
FIRM LOAD OBLIGATION	4,014	4,057	4,112	4,177	4,214	4,265
RESERVES						
TOTAL PLANNING RESERVE MARGIN	482	487	493	501	506	512
CAPACITY NEED	4,496	4,544	4,606	4,679	4,720	4,777
CAPACITY POSITION	1,109	1,061	994	616	688	618
TOTAL SALES / (PURCHASES) (MW)	531	0	0	0	0	0
POSITION						
RESOURCE POSITION (MW): LONG/(SHORT)	578	1,061	994	616	688	618

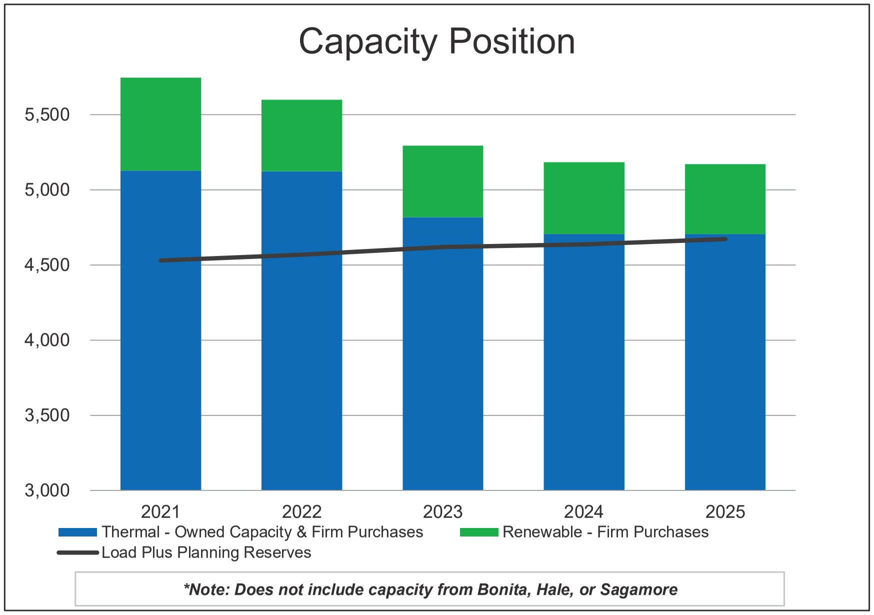
Capacity Mix



** The above chart represents the maximum output of each facility*

Action Plan - SPS Loads and Resources





Note: Does not include capacity from Bonita, Hale, or Sagamore

QUESTIONS AND DISCUSSION

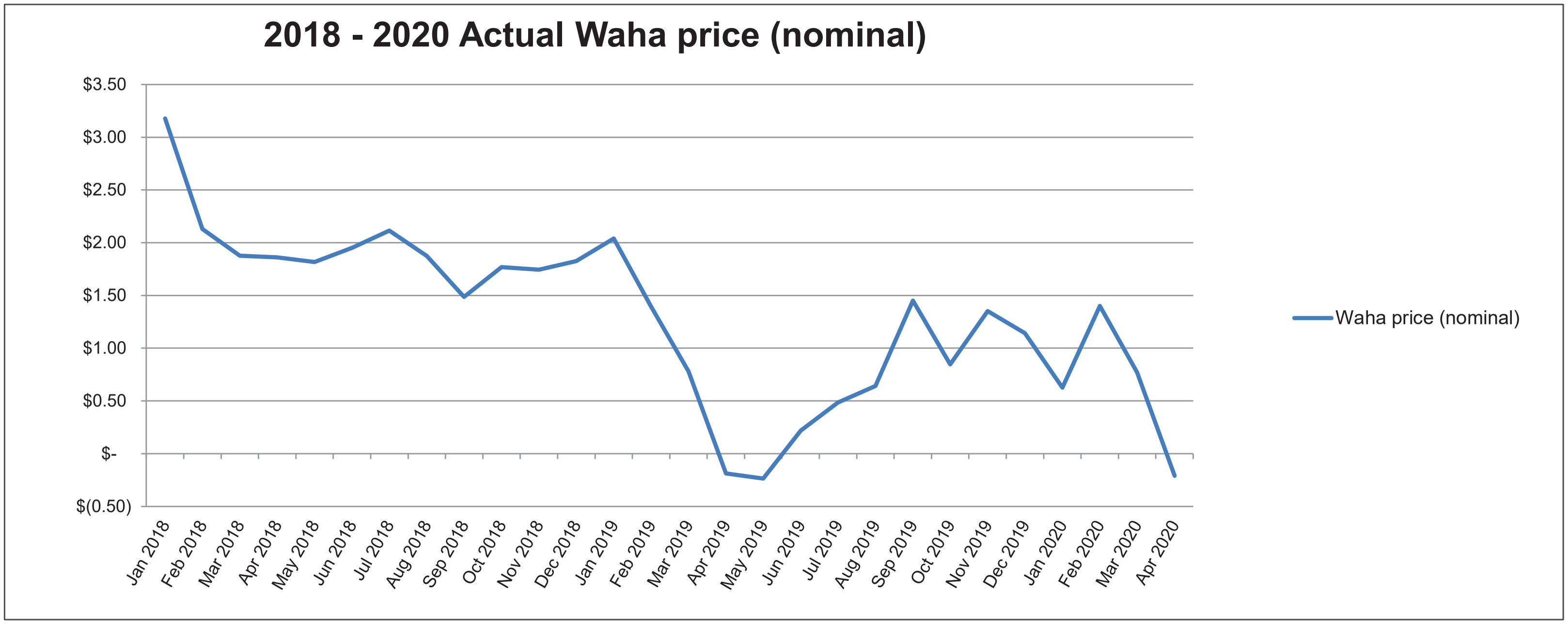
Xcel Energy®

Factors Impacting Resource Planning Since the 2018 NM IRP

Recent Impacts

- Depressed gas prices
- Increased load growth in southeast New Mexico
- New renewable resources

Gas Prices from 2018 - 2020



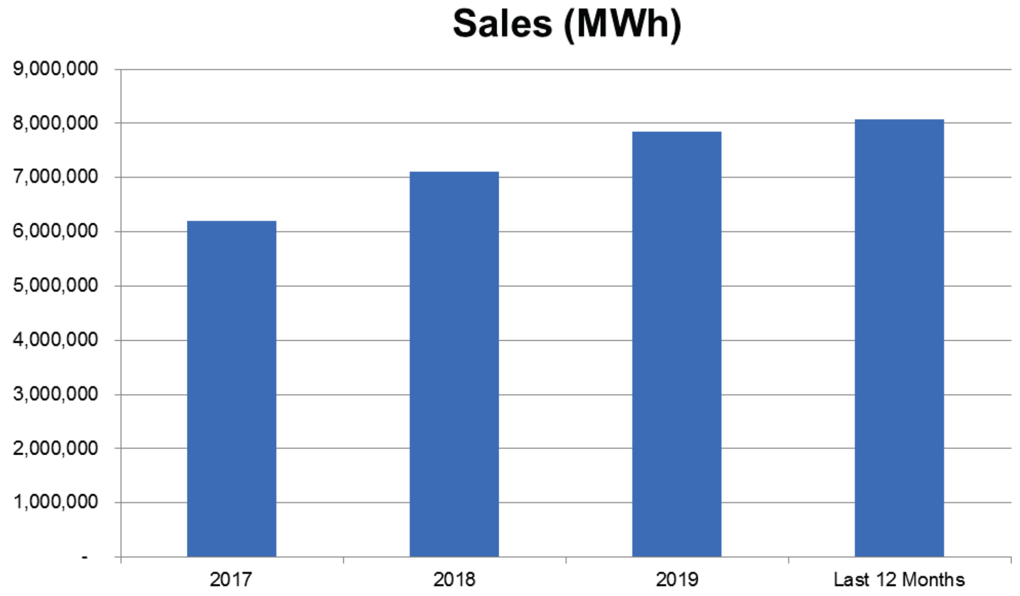
SPS's Aging Generation Fleet

- SPS has approximately 1,231 MW of natural gas-fired generation that is between 50 – 67 years old
- Plant X1 and Plant X2
  - Gas-fired steam turbines located in Lamb County, TX
  - Commercial operation date ("COD") of 1952 and 1953 respectively
- Cunningham 1
  - Gas-fired steam turbine located in Lea County, NM
  - COD of 1957
- These natural gas fired-units were originally scheduled to retire in 2019 & 2020 but have been kept online due to anomalously low natural gas prices in SPS's service area

SPS's New Wind Facilities

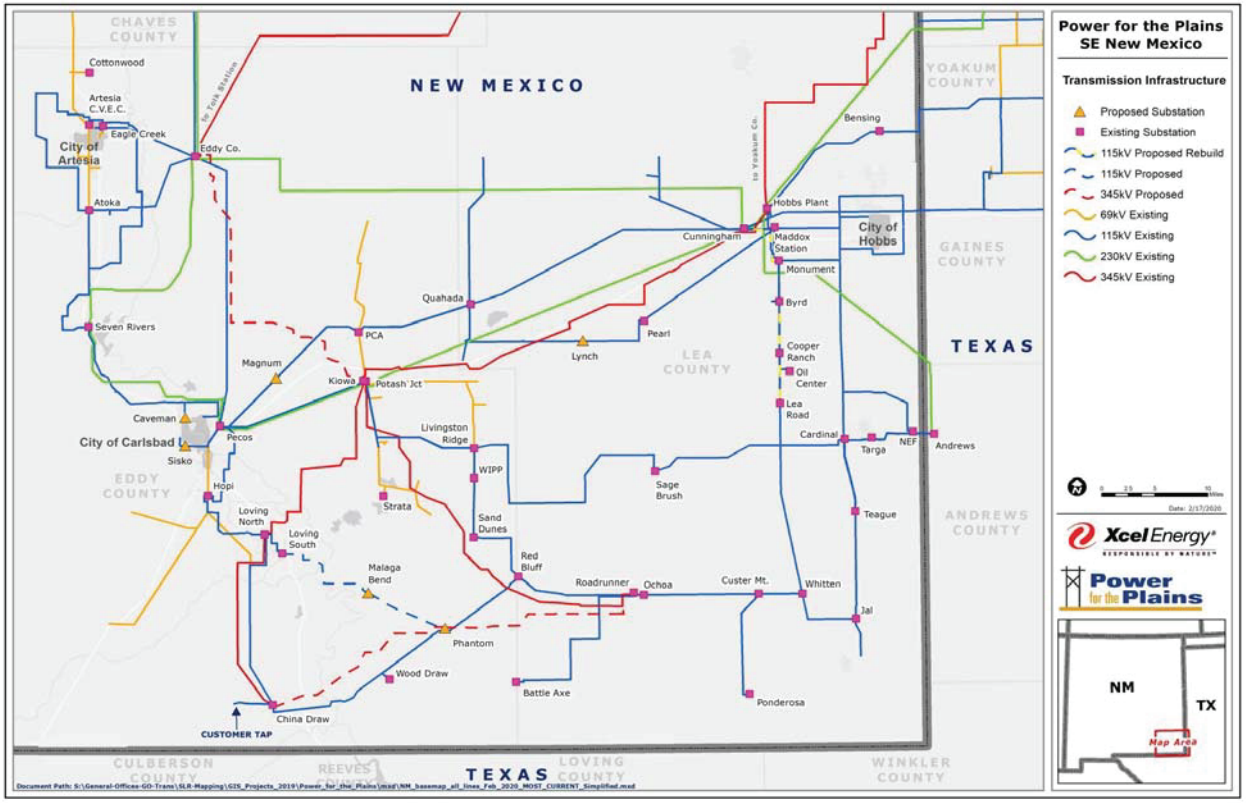
- Hale Wind (Owned) – Hale County, TX
  - 478 MW COD of 6/2019
  - Approximately $700 million dollars of investment
- Sagamore Wind (Owned) – Roosevelt County, NM
  - 522 MW planned COD of 12/2020
  - Approximately $900 million dollars of investment
- Lorenzo and Wildcat Purchased Power Agreements ("PPA") – Crosby & Cochran County, TX
  - Formally known as Bonita I & II
  - Wildcat 150 MW COD of 12/2018 – Crosby County, TX
  - Lorenzo 80 MW COD of 12/2018 – Cochran County, TX
- SPS acquired the three wind facilities to provide economic energy and lower customer bills

Oil & Gas Growth in Southeast New Mexico



Years	% Increase (MWh)
2017 - 2018	15%
2018 - 2019	10%
2019 - Last 12 Months	3%

Transmission Projects – Southeast New Mexico



Completed Transmission Projects SE NM

2015 - 2019

- 520 miles of new transmission line
- 500 miles of new distribution line
- SPS has built enough new transmission line that it could almost span diagonally across the entire state of NM
- SPS has invested approximately $626 million dollars on transmission infrastructure

Planned Transmission Projects SE NM

2020 – 2021

- 115 kV – 21 miles
- 345 kV – 180 miles
- SPS is planning to invest an additional $170 million on transmission infrastructure
- SPS expects to continue to invest significant capital in its service area in NM as the electrical loads continue to grow

2019 – 2020 Completed Transmission Projects in SE NM

- NEF to Targa 115 kV rebuild (In-Service Date (“ISD”): March 2019)
- Potash Junction – Livingston Ridge 115 kV rebuild (ISD: April 2019)
- Hobbs Plant – Yoakum 345 kV (ISD: May 2019)
- China Draw – Customer Tap 115 kV (ISD: May 2019)
- Roadrunner Distribution Substation addition (ISD: August 2019)
- Eddy Co 230 kV double breaker double bus (ISD: November 2019)
- North Loving – Loving South 115 kV (ISD: December 2019)
- New Loving South Substation (ISD: December 2019)
- Cunningham – Monument Tap 115 kV rebuild (ISD: December 2019)
- Red Bluff to Phantom 115 kV rebuild (ISD: March 2020)

2020 - 2021 Planned Transmission Projects in SE NM

- TUCO – Yoakum 345 kV (ISD: June 2020)
- Medanos Distribution Substation (ISD: October 2020)
- Eddy County – Kiowa 345 kV (ISD: November 2020)
- Loving South – Malaga Bend - Phantom 115 kV (ISD: November 2020)
- Malaga Bend Distribution Substation (ISD: November 2020)
- Phantom 115kV Substation (ISD: November 2020)
- China Draw – Phantom – Roadrunner 345 kV (ISD: November 2021)

Power for the Plains: Transmission Expansion Plan for Texas and southeast New Mexico

For Details Visit: www.powerfortheplains.com/

QUESTIONS & DISCUSSION

Future Impacts on Resource Planning

- Area near Harrington Station is being monitored for NAAQS compliance and will be designated as either meeting the standard or nonattainment. Texas plan will be due beginning of 2026
- Ongoing Tolk Station depleting groundwater and end-of-year 2032 retirement
- SPS's aging generation fleet
- SPP Interconnect queue
- Energy Storage / Emerging Technologies

QUESTIONS & DISCUSSION

Xcel Energy®

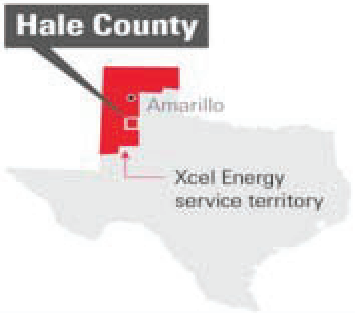
Hale and Sagamore Wind Facilities

Brian Hudson | Energy Supply Project Manager

5/21/2020

Hale Wind Project

Location:	Hale County, Texas
Size:	478 MWs (~170,000 homes)
Turbines:	Vestas 80m HH V110 / 80m HH V116 / 94m HH V116
Boundary:	~65,000 acres
Generator T-Line:	~14 miles
Start Construction:	June 2018
COD:	June 2019
Interconnection:	TUCO Substation
Capacity Factor:	~54.0%



Hale: 478 MW

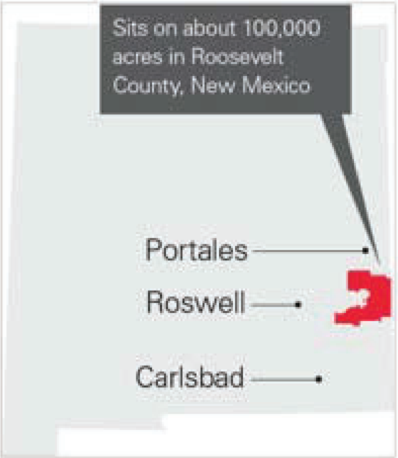
Deal type: **Self-build**

Commercial operation by:

2019

Sagamore Wind Project

Location: Roosevelt County, New Mexico
Size: 522 MWs
Turbines: 240 (Vestas 80m HH V110 / Vestas 80m HH V120)
Boundary: ~100,000 acres
Generation T-Line: ~14 miles
Start Construction: November 2019
Completion: December 2020
Interconnection: Crossroads Substation
Capacity Factor: ~53.0%


Sits on about 100,000 acres in Roosevelt County, New Mexico

$131.5 million
in state and local benefits over life of project*

240
turbines

522
megawatts

98%
of footprint remains in agricultural use

$43 million
in gross receipts tax*

WANZEK
a MasTec company

Xcel Energy®

Wind Turbine Construction - Foundations

- One foundation – 350 yards of concrete
- Hale (239 turbines) – 85,000 yards
- Sagamore (240 turbines) – 86,000 yards
- Enough concrete at Hale and Sagamore to build a sidewalk from Amarillo, TX to Los Angeles, CA

Wind Turbine Construction - Electrical

- Hale – 3 million feet of underground conductor. 1 million feet of ground wire. 1 million feet of fiber optic cable.
- Sagamore – 3 million feet of underground conductor. 1 million feet of ground wire. 1 million feet of fiber optic cable.
- Hale/Sagamore have enough underground cable to stretch from Mexico to Canada borders.

Wind Turbine Construction - Turbines

- Hale – 478 MW. 239 turbines. 2,078 individual truck loads of components. 499 feet tall.
- Sagamore – 522 MW. 240 turbines. 1,920 individual truck loads of components. 470 feet tall.
- Hale/Sagamore can power 350,000 homes.

QUESTIONS & DISCUSSION

Topics for Future Meetings

- Environmental Updates
- Sales and Load Forecasting
- Gas & Power Markets
- Coal Supply
- Demand-side Management and Energy Efficiency
- Energy Storage

NM IRP Details

- Web Page -

  https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/2022_new_mexico_integrated_resource_plan

  ** Note: In the upper-left hand corner of the webpage there is a drop-down, select “New Mexico”. For the Service Area, click on New Mexico. At the bottom of the page click on the Public Advisory Meeting tab, then click on the date for the first public meeting*

- Resource Planning Contacts –
  - Bennie Weeks | Manager of Resource Planning & Bidding | Bennie.Weeks@xcelenergy.com
  - Ben Elsey | Resource Planning Analyst | Ben.R.Elsey@xcelenergy.com
  - Ashley Gibbons | Resource Planning Analyst | Ashley.Gibbons@xcelenergy.com
- Regulatory Contacts –
  - Linda Hudgins | Case Specialist II | *Linda.L.Hudgins@xcelenergy.com*
  - Mario Contreras | Rate Case Manager | *Mario.A.Contreras@xcelenergy.com*

Next Meeting

Date: August 20, 2020

Time: 10:00 AM Mountain Time

Location: Webinar

Note: The 1st Technical Conference will be held shortly after the final order for the Tolk Analysis pursuant to the Stipulation in Case No. 19-00170-UT

Xcel Energy®

2021 SPS New Mexico Integrated Resource Plan: 2nd Public Advisory Meeting

8/20/2020

© 2020 Xcel Energy

TOPICS FOR DISCUSSION

- Emerging Environmental Impacts for SPS
- Harrington National Ambient Air Quality Standards (NAAQS) Compliance
- Questions and Discussion
- Future Meeting Topics
- Next Meeting

ENVIRONMENTAL IMPACTS FOR SPS

Dean Metcalf | Manager of Environmental Services

P: 806-378-2194 | C: 720-480-5632

8/20/2020

MAJOR REGULATIONS AFFECTING SPS

Cross-State Air Pollution Rule (CSAPR)

- Environmental Protection Agency (EPA) adopted in 2011 (Xcel Energy (SPS) made comments and sued EPA)
- Two Main Issues – Texas' Inclusion and EPA Disapproval of Texas State Plan
- DC Circuit Court Stayed CSAPR - December 30, 2011
- Litigation went from DC Circuit Court to Supreme Court and back
- CSAPR largely upheld, but Texas emission budgets were found to over-control and were remanded to EPA

MAJOR REGULATIONS AFFECTING SPS

Cross-State Air Pollution Rule (CSAPR) continued…

- CSAPR program took effect January 1, 2015
- EPA made summer nitrogen oxides (NOx) budget tighter, and removed Texas from CSAPR limits for annual NOx and sulfur dioxide (SO_2) in 2016-17
- Changes in SPS since 2011 (added wind and transmission)
- Compliance Strategy – dispatch and allowance purchase
- As of now, no additional controls required

MAJOR REGULATIONS AFFECTING SPS

EGU MACT – MATS Rule Regulates

- Mercury (Hg)
- Particulate Matter (PM) – surrogate for toxic non-mercury metals
- Hydrogen Chloride (HCl) – surrogate for all toxic acid gases
- Compliance Strategy – Activated carbon injection (ACI) and PM Averaging Plan for Harrington 1, Harrington 2, & Harrington 3.
- 2015 Compliance (Tolk and Harrington)

MAJOR REGULATIONS AFFECTING SPS

Coal Combustion Residuals (CCR) Rules

- Regulation of coal ash as nonhazardous
- Increased landfill construction & monitoring requirements once our ash becomes non-saleable
- Potential to affect ash sales – 100% beneficial use

MAJOR REGULATIONS AFFECTING SPS

Affordable Clean Energy Rule (ACE)

- 2018 ACE Rule replaces EPA’s Clean Power Plan
- Seeks carbon dioxide (CO_2) reduction through the implementation of Heat Rate Improvement (HRI)
- Impacts Harrington and Tolk in SPS (combustion turbine sources not impacted by ACE)
- Prescriptive list of 7 “candidate technologies” for HRI
- Tasks states with defining unit level plan for compliance
- Compliance 2024

MAJOR REGULATIONS AFFECTING SPS

Affordable Clean Energy Rule (ACE) continued…

- Compliance demonstrated by proposing heat rate improvement that translates to a CO_2 reduction as measured by Continuous Emission Monitoring System (CEMS) (CO_2 lb/net or gross MW basis)
- Baseline CO_2 established from historical data
- Compliance demonstrated by reduction of "X%" from baseline
- States may consider remaining useful life in establishing standard of performance

MAJOR REGULATIONS AFFECTING SPS

Affordable Clean Energy Rule (ACE) continued…

- Texas Commission on Environmental Quality (TCEQ) has issued preliminary information request for impacted sources seeking baseline CO_2 and heat rate information
- Due back October 30th, 2020
- Harrington units will no longer be subject to following fuel switching to gas
- Currently compiling information for Tolk 1 and 2

MAJOR REGULATIONS AFFECTING SPS

Threatened and Endangered Species

- Sand Dune Lizard
- Lesser Prairie Chicken

Avian Protection Plan

- APP

REGULATIONS NOT IMPACTING SPS

- CCR – Coal Combustion Residual rule or Ash Rule
- 316(b) – Water Intake Structure Rule
- WOTUS – Waters of the United States

RECENT PERMITTING ACTIONS IN SPS

- Tolk Permit Reissuance
  - Will likely result in carbon monoxide (CO) continuous monitoring
  - Additional volatile organic compounds (VOC) stack testing
- City of Amarillo and Nichols/Harrington Wastewater Permit
- Sagamore
- Hale
- Potential for additional renewables

HARRINGTON NAAQS COMPLIANCE

8/20/2020

HARRINGTON STATION – NAAQS COMPLIANCE

- Thunder Basin (WY) low-sulfur coal

- Unit 1 – 347 MW – 1976 [45]
- Unit 2 – 347 MW – 1978 [43]
- Unit 3 – 347 MW – 1980 [41]

- 1,041 MW net capability

- Amarillo City effluent cooling water source

BACKGROUND

- The Clean Air Act requires the EPA to set NAAQS (including SO_2)
- In December 2016, TCEQ installed an SO_2 monitor in the vicinity of Harrington Station to collect ambient air data
- Readings from the monitor exceed the standards
- Harrington emits ~99% of the SO_2 emissions in Potter County
- Emphasis will be on SPS to produce implementation plan
- Anticipated compliance date: By 2025

HARRINGTON STATION – NAAQS COMPLIANCE

- None of the three coal units at Harrington have SO_2 scrubbers
  - There has not been a question on SO_2 emission compliance in the past
- In June 2016, the federal EPA deemed Potter County as ‘unclassifiable’ for SO_2 emissions under the NAAQS
- TCEQ installed an air monitor near Harrington Station in December 2016
  - Under NAAQS, TCEQ must get a three-year average of SO_2 emissions to determine if sources in the area exceed the NAAQS standard
- In March 2020, the TCEQ provided SPS information indicating an alleged violation of the NAAQS requirements and referral to enforcement. [115 parts per billion vs 75 ppb NAAQS standard]

HARRINGTON STATION - NAAQS COMPLIANCE

- We believe NAAQS SO_2 emissions compliance will need to be achieved by 2025 – TCEQ has authority to force changes at Harrington to achieve the NAAQS
- Options to achieve compliance are:
  - Install scrubbers
  - Retire units (lose 1100 MW capacity)
  - Convert to natural gas-fueled boilers
- Scrubbers on each unit would cost about $180 million each
  - The Harrington units have less than 11 to 15 years life at the year 2025
- Least-cost plan is to retro-fit boilers to burn natural gas
- SPS will build a 20-mile approximately $45 million pipeline to bring more gas supply
  - Boiler burner retro-fits investment is approximately $10 million

QUESTIONS & DISCUSSION

TOPICS FOR FUTURE MEETINGS

- Sales and Load Forecasting
- Gas & Power Markets
- Coal Supply
- Demand-side Management and Energy Efficiency
- Energy Storage

NM IRP DETAILS

- Web Page -

  https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/2022_new_mexico_integrated_resource_plan

  ** Note: For the Service Area, click on New Mexico. At the bottom of the page click on the Public Advisory Meeting tab, then click on the date for the first public meeting*

- Resource Planning Contacts –
  - Bennie Weeks | Manager of Resource Planning & Bidding | Bennie.Weeks@xcelenergy.com
  - Ben Elsey | Resource Planning Analyst | Ben.R.Elsey@xcelenergy.com
  - Ashley Gibbons | Resource Planning Analyst | Ashley.Gibbons@xcelenergy.com
- Regulatory Contacts –
  - Linda Hudgins | Case Specialist II | *Linda.L.Hudgins@xcelenergy.com*
  - Mario Contreras | Rate Case Manager | *Mario.A.Contreras@xcelenergy.com*

NEXT MEETING

Date: January 12, 2021

Time: 10:00 a.m. Mountain Time

Location: Zoom Meeting

2021 SPS New Mexico Integrated Resource Plan: 3rd Public Advisory Meeting

January 12, 2021

© 2020 Xcel Energy

Topics For Discussion

- Introduction to the New Mexico Integrated Resource Plan
- New Mexico Energy Efficiency and Load Management Programs
- Sales and Load Forecasting
- Questions and Discussion
- Future Meeting Topics
- Next IRP Public Meeting

Introduction To The New Mexico Integrated Resource Plan

- Scope – Effective April 16, 2007, the NM IRP applies to all electric utilities subject to the NM Public Regulatory Commission's jurisdiction over integrated resource planning
- Objective – The purpose of the IRP is to set forth the Commission's requirements for the preparation, filing, review and acceptance of integrated resource plans by public utilities supplying electric service in New Mexico in order to identify the most cost-effective portfolio of resources to supply the energy needs of customers.
- Task – Public utilities supplying electric service to customers shall file an IRP, along with an action plan, with the commission every 3 years

Introduction To The NM IRP Continued…

- Contents of the IRP
  1) Description of existing electric supply-side and demand-side resources
  2) Current load forecast as described in this rule
  3) Load and resources table
  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 public advisory process
  9) Action plan, and
  10) Other information that the utility finds may aid the commission in reviewing the utility's planning processes

- A copy of the current IRP rule can be found at the following link:

  http://164.64.110.239/nmac/parts/title17/17.007.0003.htm

SPS NM ENERGY EFFICIENCY AND LOAD MANAGEMENT PROGRAMS

Jeremy Lovelady | Senior Regulatory Analyst

January 12, 2021

OVERVIEW

- Efficient Use of Energy Act (EUEA) Updates
- Recent EE/LM Plan Filing & Outcome
- 2020-2022 Approved Program Forecasts
- Upcoming Plan Filings

EFFICIENT USE OF ENERGY ACT (EUEA) HISTORY

- 2007 Legislation - SPS is required to achieve savings of no less than 8% of 2005 total retail kWh to New Mexico customers in 2020 as a result of energy efficiency and load management programs implemented starting in 2007
  - SPS met the requirement following the 2018 savings evaluation (8.06%)
  - SPS also met the requirement following the 2019 savings evaluation (8.54%)
- 2019 Legislation – SPS is required to achieve savings of no less than 5% of 2020 total retail kWh sales to New Mexico customer classes that have the opportunity to participate in calendar year 2025 as a result of energy efficiency and load management programs implemented in years 2021 through 2025

RECENT EE/LM PLAN FILINGS

- NMPRC Rule Change in 2017
  - Required Utilities to file Triennial Plan Filings- Staggered
- SPS filed May 15, 2019
  - Covered Plan Years 2020-2022
  - Removal of LM offerings
  - Saver’s Switch, Thermostats, ICO
  - Addition of Heat Pump Water Heaters
  - Settlement- Final Order on Feb 19, 2020
  - Small program changes
  - Additional Market Research funding for Potential Study

2020 APPROVED PROGRAM FORECAST

2020	Electric Budget	Net Customer kW	Net Customer kWh
Residential Segment			
Energy Feedback	$143,485	866	4,720,924
Heat Pump Water Heaters	$44,500	25	185,716
Home Energy Services: Residential and Low Income	$2,193,861	904	8,963,155
Home Lighting & Recycling	$1,199,817	973	5,642,488
Residential Cooling	$43,040	39	125,177
School Education Kits	$145,417	10	376,378
Smart Thermostats	$142,500	0	825,149
Residential Segment Total	**$3,912,620**	**2,785**	**20,853,234**
Business Segment			
Business Comprehensive	$4,798,684	2,263	15,985,365
Business Segment Total	**$4,798,684**	**2,263**	**15,985,365**
Planning and Research Segment			
Consumer Education	$200,000	0	0
Market Research	$110,000	0	0
Measurement & Verification	$15,000	0	0
Planning & Administration	$285,000	0	0
Product Development	$190,000	0	0
Planning & Research Segment Total	**$800,000**	**0**	**0**
PORTFOLIO TOTAL	**$9,511,304**	**4,985**	**36,885,682**

2021 APPROVED PROGRAM FORECAST

2021 Modified by Settlement	Electric Budget	Net Customer kW	Net Customer kWh
Residential Segment			
Energy Feedback	$143,485	778	4,291,520
Heat Pump Water Heaters	$78,500	45	337,666
Home Energy Services: Residential and Low Income	$2,213,861	904	8,963,155
Home Lighting & Recycling	$1,169,217	951	5,514,523
Residential Cooling	$43,040	39	125,177
School Education Kits	$145,917	10	376,378
Smart Thermostats	$122,500	0	698,746
Residential Segment Total	**$3,916,520**	**2,733**	**20,320,915**
Business Segment			
Business Comprehensive	$5,682,482	2,764	19,763,161
Business Segment Total	**$5,682,482**	**2,764**	**19,763,161**
Planning and Research Segment			
Consumer Education	$200,000	0	0
Market Research	$360,000	0	0
Measurement & Verification	$15,000	0	0
Planning & Administration	$290,000	0	0
Product Development	$190,000	0	0
Planning & Research Segment Total	**$1,055,000**	**0**	**0**
PORTFOLIO TOTAL	**$10,654,002**	**5,425**	**40,134,737**

2022 APPROVED PROGRAM FORECAST

2022 Modified by Settlement	Electric Budget	Net Customer kW	Net Customer kWh
Residential Segment			
Energy Feedback	$144,485	708	3,947,163
Heat Pump Water Heaters	$68,500	57	422,082
Home Energy Services: Residential and Low Income	$2,163,861	904	8,963,155
Home Lighting & Recycling	$1,158,151	914	5,300,679
Residential Cooling	$68,540	39	125,177
School Education Kits	$166,417	10	376,378
Smart Thermostats	$82,500	0	742,417
Residential Segment Total	**$3,852,454**	**2,637**	**19,890,259**
Business Segment			
Business Comprehensive	$5,741,548	2,797	20,111,128
Business Segment Total	**$5,741,548**	**2,797**	**20,111,128**
Planning and Research Segment			
Consumer Education	$200,000	0	0
Market Research	$360,000	0	0
Measurement & Verification	$15,000	0	0
Planning & Administration	$295,000	0	0
Product Development	$190,000	0	0
Planning & Research Segment Total	**$1,060,000**	**0**	**0**
PORTFOLIO TOTAL	**$10,654,002**	**5,363**	**40,052,074**

UPCOMING PLAN FILINGS

- 2021 Limited Filing
  - Filing of SPS’s proposed EUEA goal – based on 2020 Sales
  - Present Potential Study
  - Update PY 2022 program offerings and goals
- SPS 2022 Triennial Plan Filing
  - Covering PY 2023-2025
  - Program updates/inclusions based on Potential Study recommendations.

CONTACT INFORMATION

Jeremy Lovelady: 303-294-2201

Jeremy.m.lovelady@xcelenergy.com

Southwestern Public Service Company

Sales and Load Forecasting

New Mexico Resource Plan Public Advisory Meeting

January 12, 2021

Agenda

- Energy and peak demand forecasting process
- Forecast assumptions
- Energy and peak demand forecast results

FORECASTING PROCESS

- Develop 30-year forecasts of monthly customers, sales, and peak demand.
  - Regression analysis, trend analysis, input from Account Management, contract terms, and load factor analysis.
  - Includes adjustments for demand-side management, electric vehicles, individual large customer information.
- Retail sales are forecast by major class and by state.
- Retail peak demand is forecast at the aggregated company level.
- Wholesale sales and peak demand are forecast by individual customer.

REGRESSION ANALYSIS

A statistical process for estimating the relationship between monthly sales (or customers or demand) and explanatory variables such as economics, weather, customers, and price of electricity. The regression analysis result is an equation that weights the explanatory variables.

- For example: Residential Sales = (C_1 x Personal Income per Household) +   (C_2 x heating weather) + (C_3 x cooling weather)

Once a statistical relationship is established from historical data, the relationship is applied to the forecast of the explanatory variables to derive a forecast.

Strengths: industry standard, robust, test results, defines relationships, adaptable/flexible.

Weaknesses: historical relationships can change, limited by available data, extremes can create challenges.

Assumptions

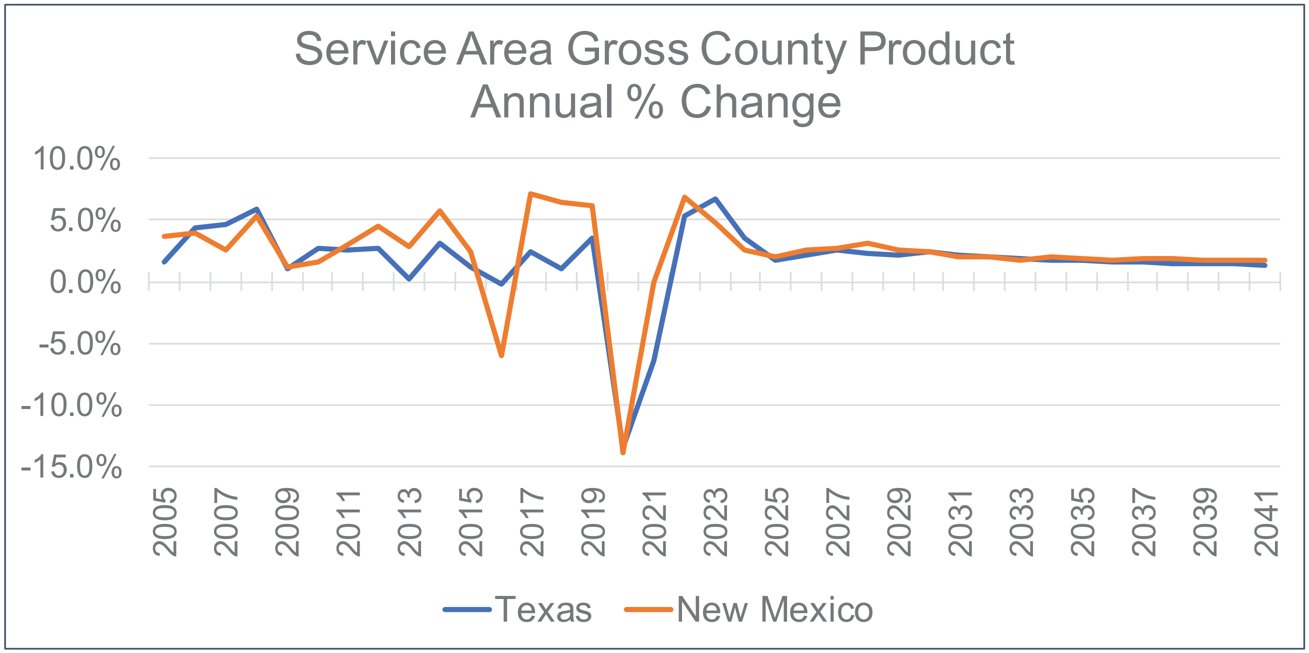
Economic and Demographic Assumptions

Economic and demographic data obtained from IHS Markit (both historical and forecast) for U.S., state and counties. County level data is aggregated to service territory.

Economic and demographic variables used in modeling include service area employment, households, personal income, population, and Gross County Product; U.S. Gross Domestic Product, and oil and gas extraction and drilling index.

Current economic outlook shows significant COVID-19 impacts in 2020 with impacts moderating through 2024/2025.

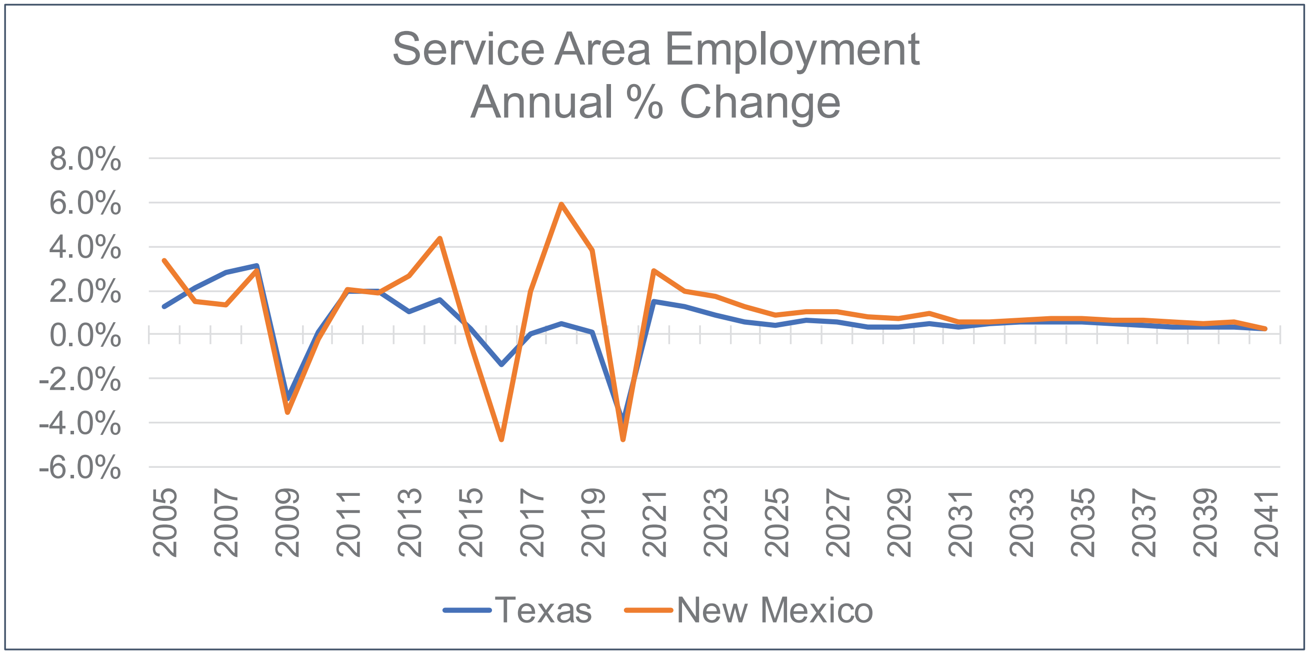
Texas and New Mexico Service Area Gross County Product Growth



Source: IHS Markit

Service Area Gross County Product is expected to return to pre-pandemic levels by late 2023 (NM) and in 2025 (TX).

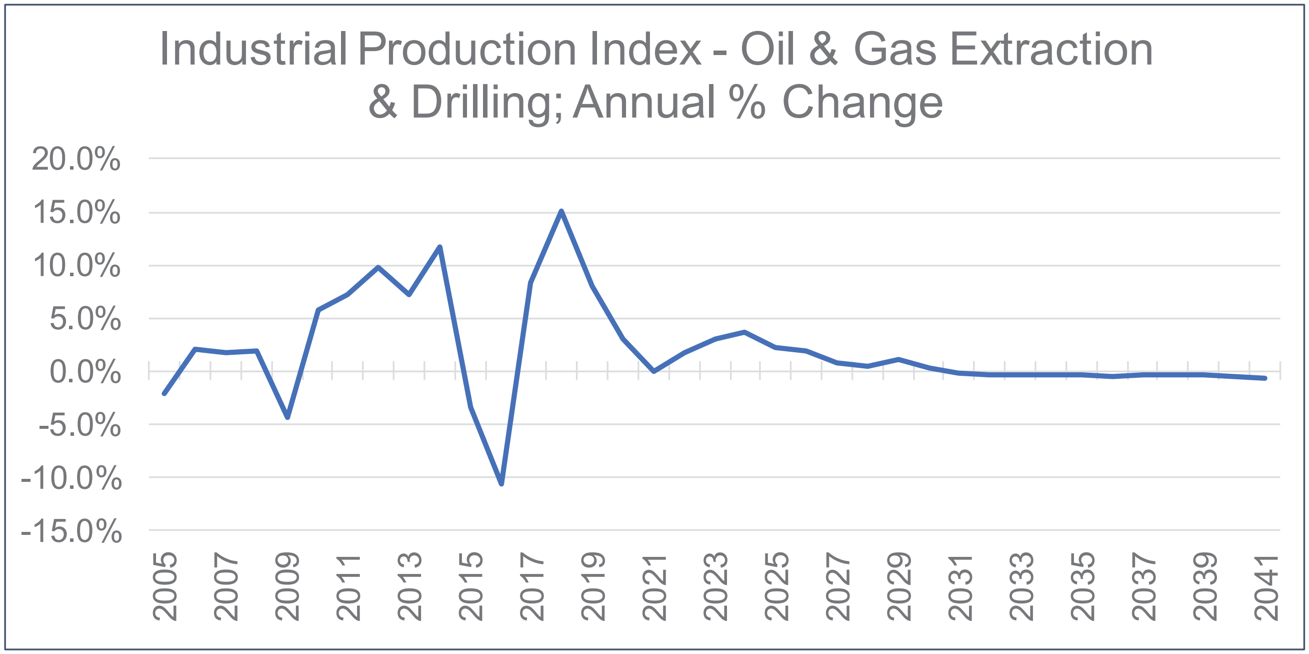
Texas and New Mexico Job Growth



Source: IHS Markit

Service Area Employment is expected to return to pre-pandemic levels by mid-2022.

Oil and Gas Extraction and Drilling



Source: IHS Markit

Oil & Gas extraction and drilling continues, but at a slower rate of growth than seen historically.

Weather Assumptions

Weather data is collected from NOAA for Amarillo, Lubbock, and Roswell.

Forecast assumes normal weather defined as 30-year rolling average.

- Includes temperature, Heating Degree Days (HDD), Cooling Degree Days (CDD), and precipitation.
- Historical sales and peak demand are weather normalized for variance analysis.

Electric Vehicle Forecast Process

- Adoption scenarios through 2035 developed using several different modeling techniques (Bass Diffusion and Econometric models).
    - Models based on annual data through 2019.
    - COVID and Recession reduces the new EV sales as well as the average miles driven.
- Forecast includes light, medium and heavy-duty vehicles.
- Peak demand impact is based on hourly charging curve.
    - Charging profile switches from Unmanaged to Managed in 2022.

Electric Vehicle Sales and Loads

	Cumulative # of EV Sales				Consumption (MWh)					Peak Demand	
	LDV	MDV	HDV	Total	LDV	MDV	HDV	Total	% of Retail Sales	MW	% of Retail Peak
2019	525	0	1	526	1,897	0	65	1,963	0.0%	0	0.0%
2020	650	0	2	652	2,287	1	268	2,556	0.0%	0	0.0%
2021	887	0	5	892	3,206	2	642	3,851	0.0%	0	0.0%
2022	1,463	0	9	1,472	4,905	7	1,224	6,136	0.0%	1	0.0%
2023	2,960	18	22	3,000	9,236	309	2,665	12,210	0.1%	1	0.0%
2024	4,603	62	47	4,712	15,797	1,298	5,816	22,911	0.1%	3	0.1%
2025	6,239	137	88	6,463	22,649	3,182	11,229	37,059	0.2%	4	0.1%
2026	8,402	247	156	8,804	30,586	6,118	20,228	56,932	0.2%	6	0.2%
2027	11,360	396	257	12,013	41,288	10,233	34,135	85,657	0.4%	9	0.2%
2028	15,642	568	393	16,603	56,417	15,317	53,525	125,259	0.5%	13	0.3%
2029	21,739	763	551	23,053	78,103	21,149	77,164	176,416	0.7%	18	0.4%
2030	30,244	1,001	746	31,991	108,615	28,062	105,092	241,768	1.0%	25	0.6%
2031	41,656	1,266	966	43,889	150,234	35,900	136,707	322,841	1.3%	34	0.8%
2032	56,894	1,559	1,215	59,668	205,919	44,541	171,354	421,813	1.7%	46	1.1%
2033	77,031	1,879	1,492	80,403	279,836	53,982	208,830	542,648	2.2%	61	1.5%
2034	101,887	2,228	1,799	105,915	373,852	64,237	249,084	687,173	2.7%	79	1.9%
2035	128,099	2,606	2,133	132,838	480,561	75,328	292,442	848,330	3.3%	100	2.4%

DEMAND-SIDE MANAGEMENT

Sales and peak demand forecasts are adjusted to account for expected incremental DSM savings.

- Incremental DSM is projected DSM savings less the amount of historical DSM savings embedded in sales and peak demand.

DSM savings are based on approved DSM filings.

Residential programs: residential lighting (LEDs), weatherization, school kits, and smart thermostats.

C&I programs: motor replacement, custom projects, business lighting, and cooling.

SPS New O&G Load

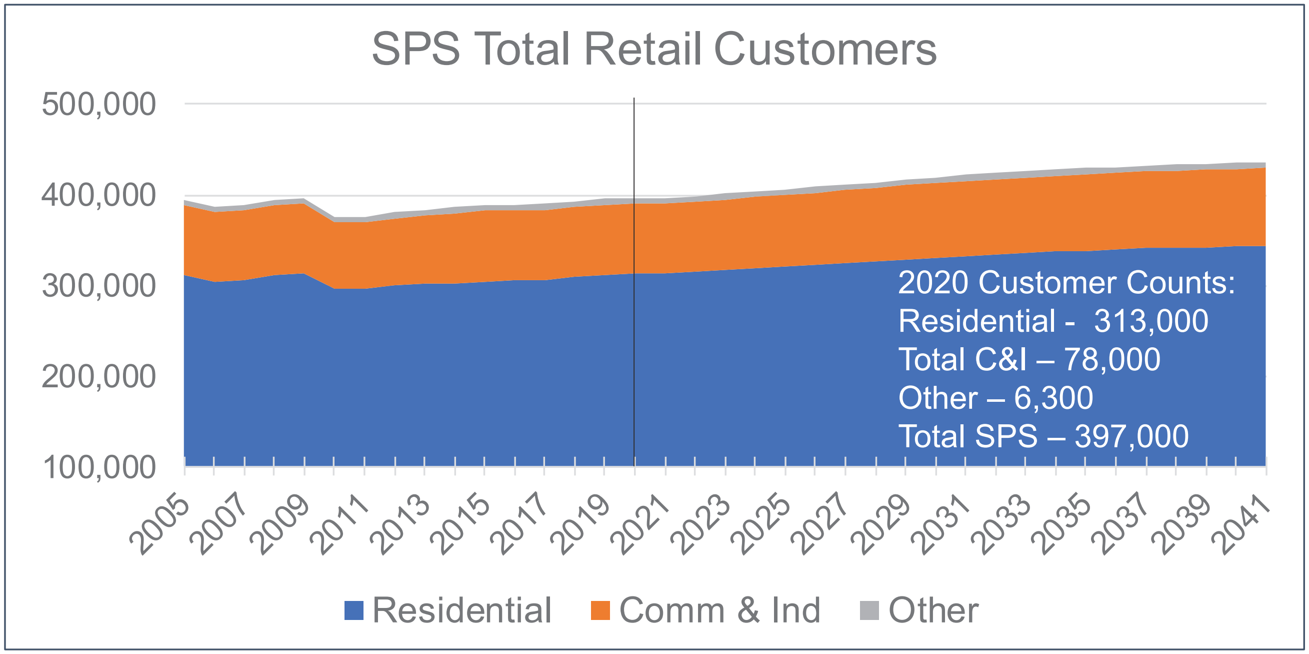
- SPS Key Account Managers provide potential new load that has been identified through conversations with the customer.
  - No new O&G load in TX.
- Total potential new load adjusted for actual achievement and timing risks.
- Only highly probable loads are included (>=80% probability)
  - Probability of achieving highly probable loads declines over time.
- Assumed to be online the quarter after service is requested.
- Ramps up to full requested capacity over 3 quarters.
- Load factor applied to derive energy impacts.

Forecast Results

SPS Forecast Key Take-Aways

- Near-term Residential use per customer is higher than recent past and Small C/I use per customer is lower.
  - Both Residential and Small C/I use per customer begin to return to long-term trends after 2020 but take several years to return to prior levels.
  - Assume losses in Small C/I sector due to business closures in “experience economy” sectors (Arts and Entertainment, Restaurants and Bars, Retail).
- Large C/I gradually recovers.
  - Slowdown in Oil and Gas extraction/drilling in 2020.
  - Additional negative impacts in 2020 and into 2021 for other mining/manufacturing customers.
- Continued declines in Wholesale as contracts ramp down/expire.

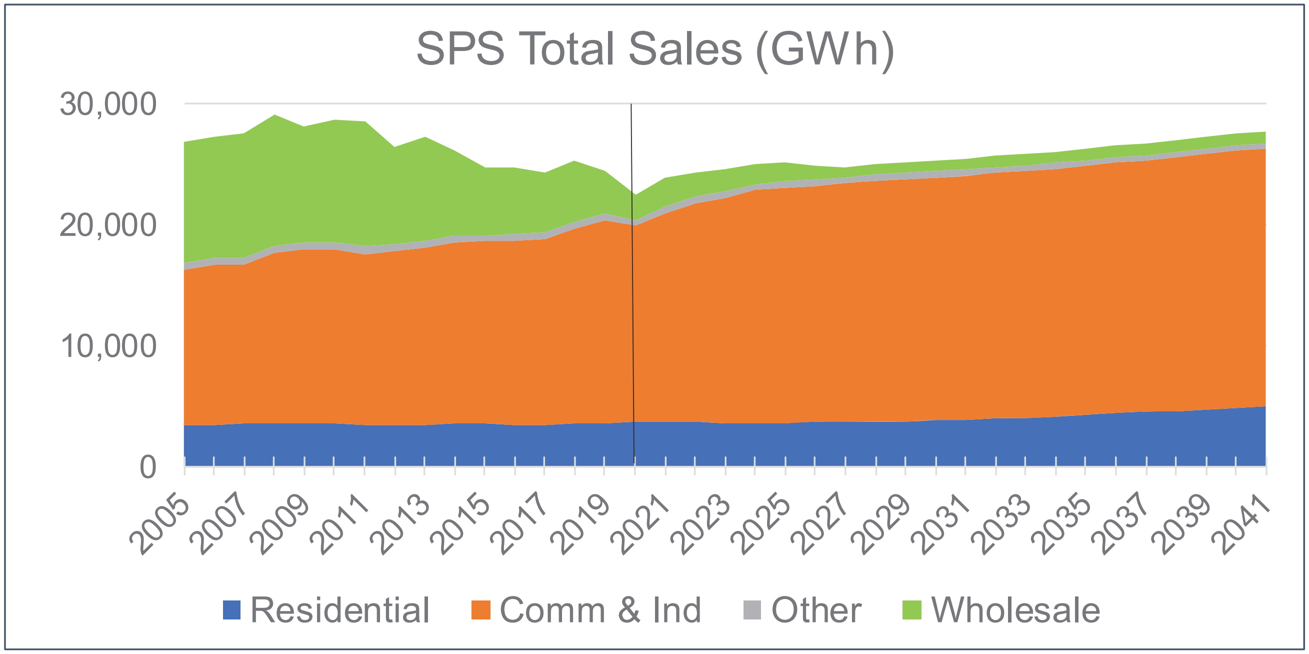
CUSTOMER FORECAST



2020 Customer Counts:
Residential - 313,000
Total C&I – 78,000
Other – 6,300
Total SPS – 397,000

Retail Avg. Annual % Ch.: 2011-2020 = 0.6% 2021–2041 = 0.4%

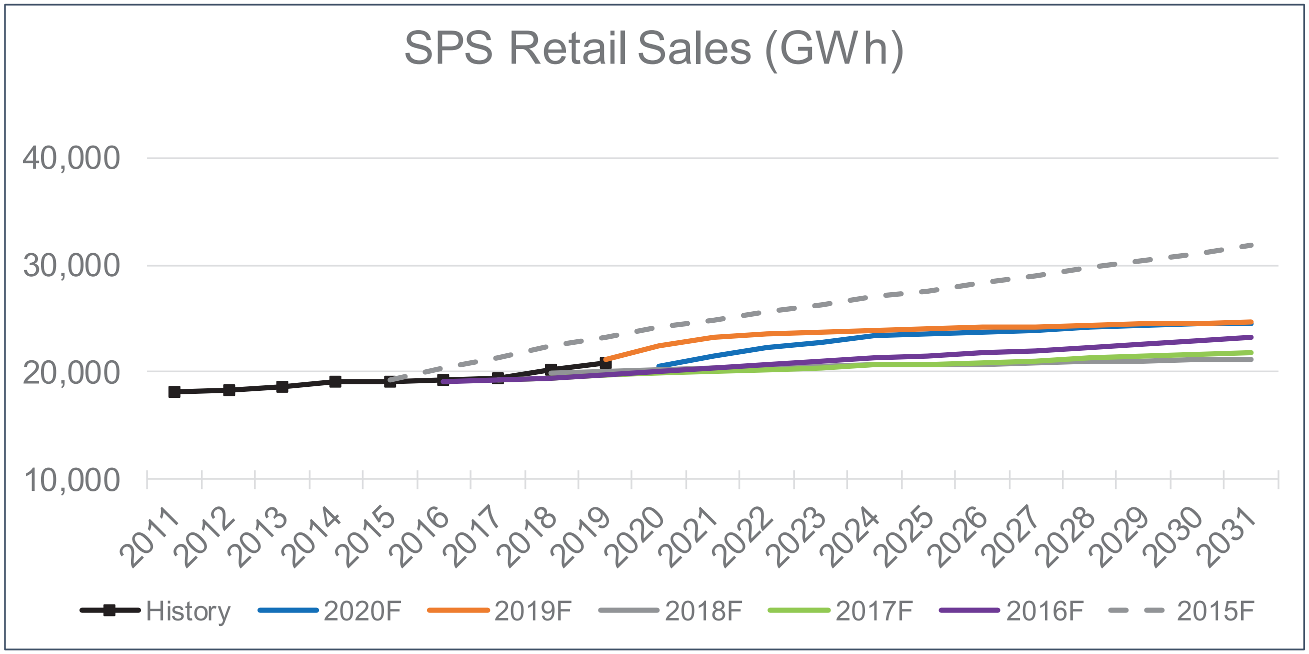
SALES FORECAST



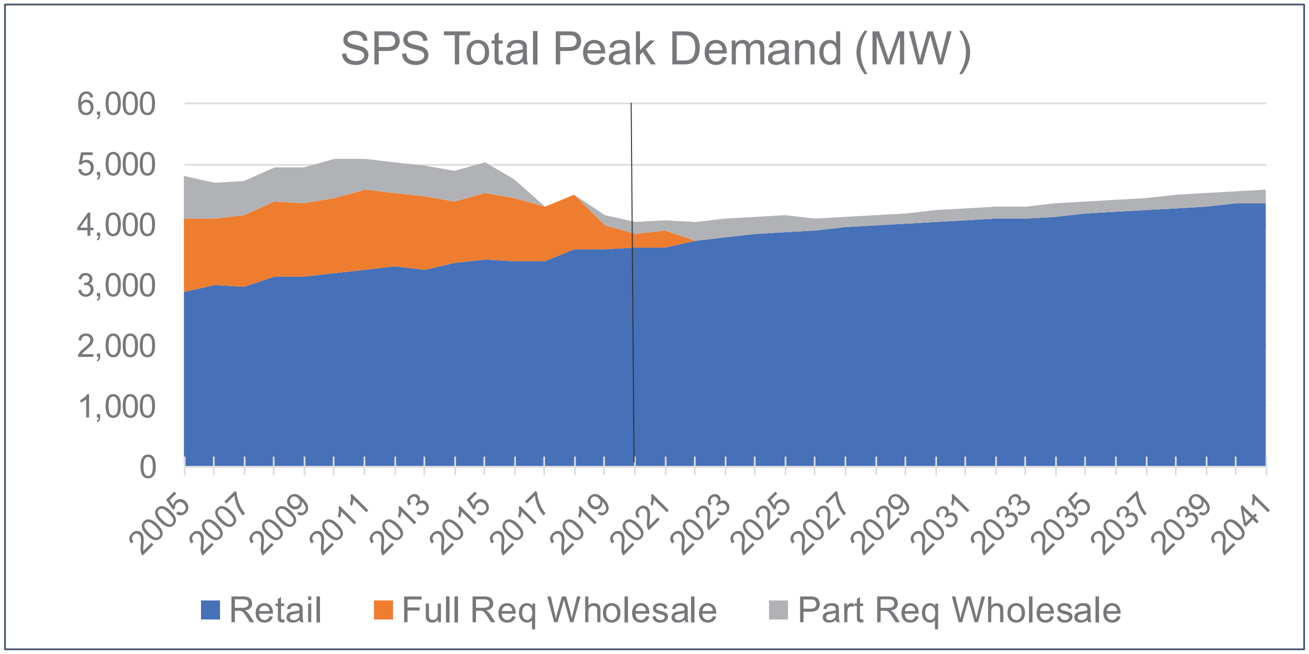
Retail Avg. Annual % Ch.: 2011-2020 = 1.0% 2021–2041 = 1.3%

SPS Total Avg. Annual % Ch.: 2011-2020 = -2.4% 2021-2041 = 1.0%

SALES FORECAST COMPARISONS



PEAK DEMAND FORECAST



Retail Avg. Annual % Ch.: 2011-2020 = 1.2% 2021–2041 = 0.9%

SPS Total Avg. Annual % Ch.: 2011-2020 = -2.3% 2021-2041 = 0.6%

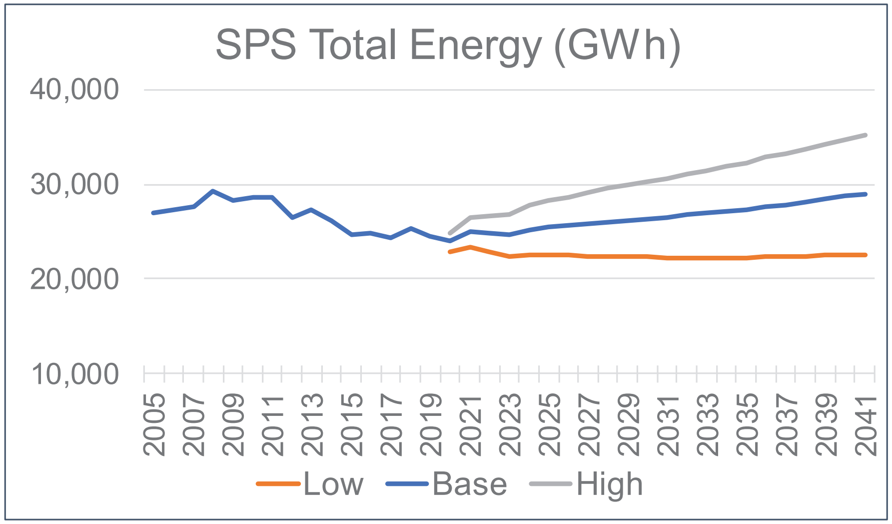
Forecast Scenarios

Probability distributions are developed by conducting Monte Carlo simulations on the main drivers of energy and peak demand forecasts (e.g., weather and economics) .

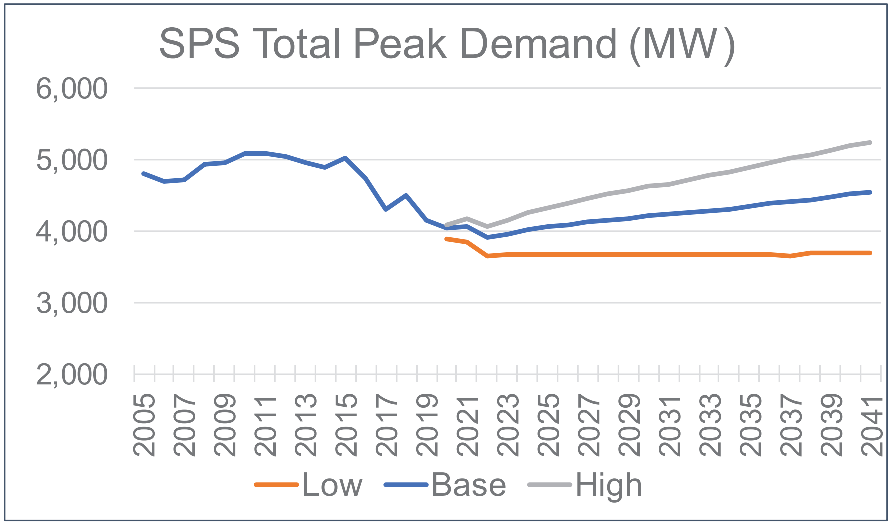
Low-growth scenario is equivalent to the 15th percentile probability distribution.

High-growth scenario is equivalent to the 85th percentile probability distribution.

FORECAST SCENARIOS



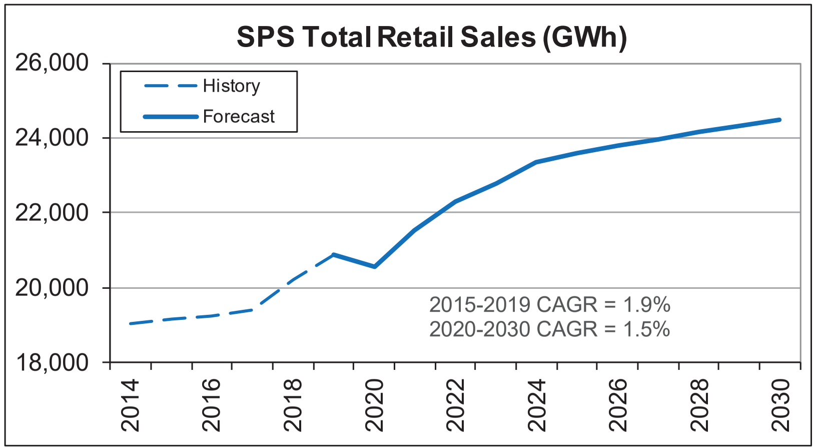
SPS Total Energy (GWh)



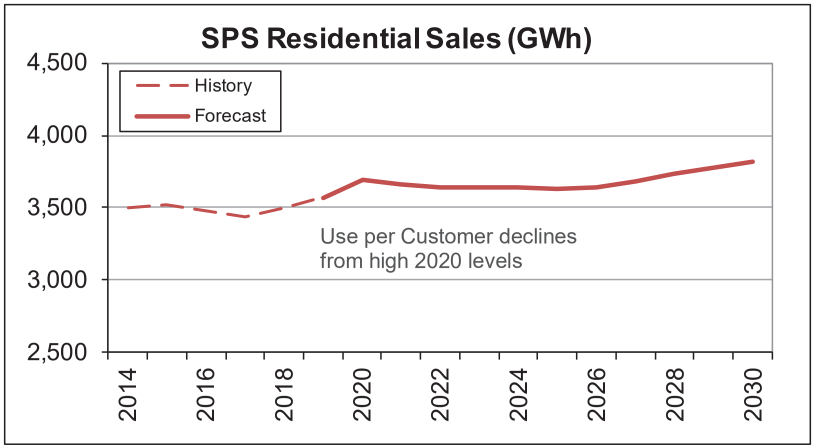
SPS Total Peak Demand (MW)

Appendix

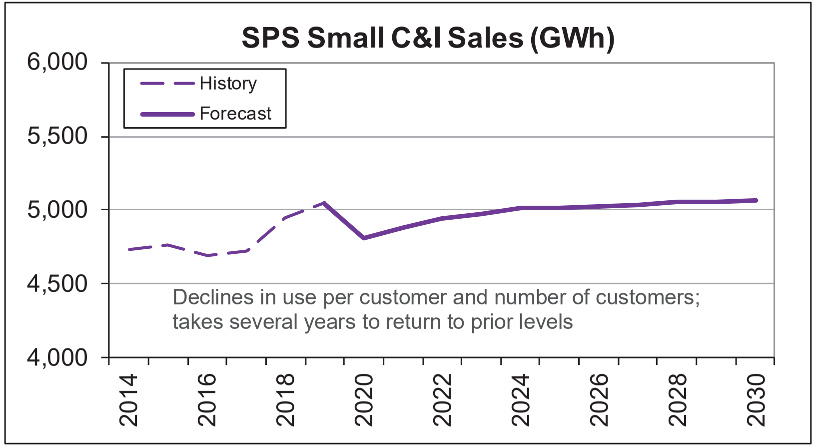
SPS Retail Sales


SPS Total Retail Sales (GWh)

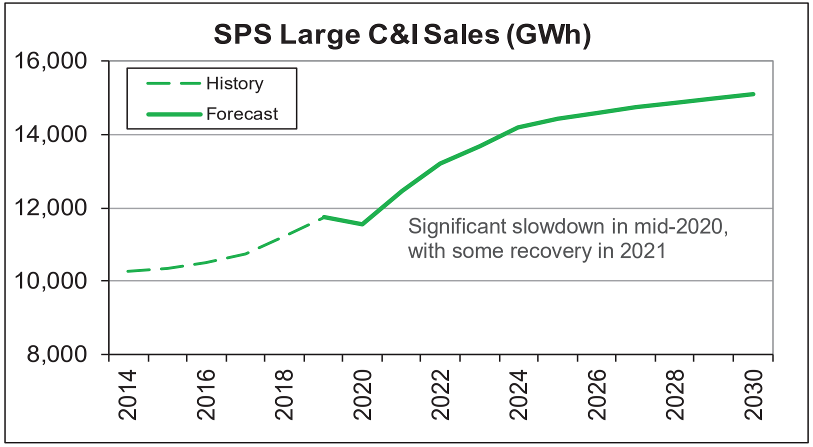
2015-2019 CAGR = 1.9%
2020-2030 CAGR = 1.5%


SPS Residential Sales (GWh)

Use per Customer declines
from high 2020 levels

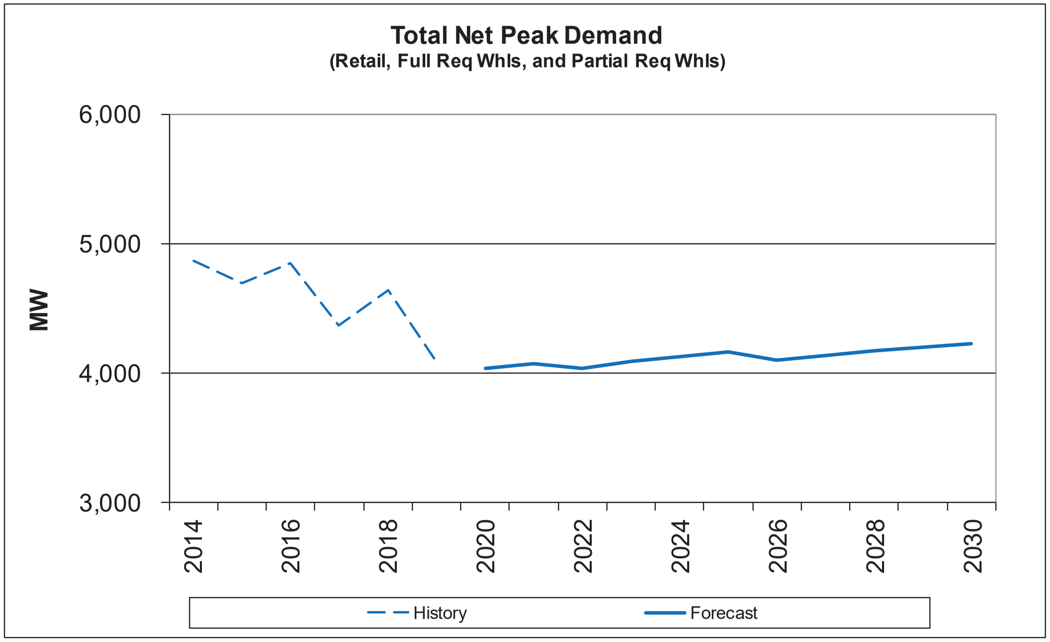

SPS Small C&I Sales (GWh)

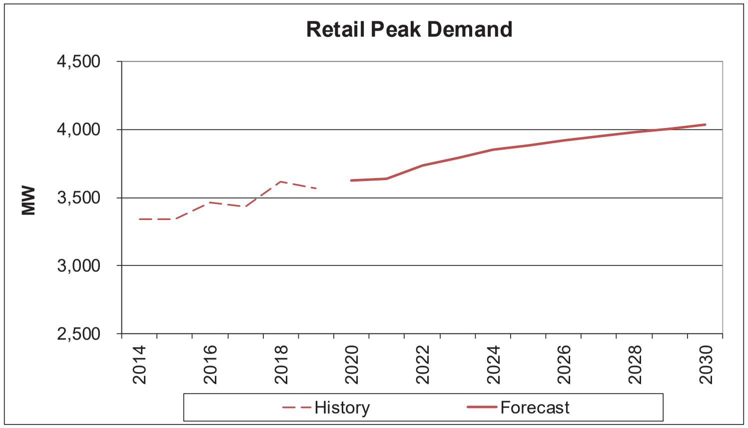
Declines in use per customer and number of customers;
takes several years to return to prior levels

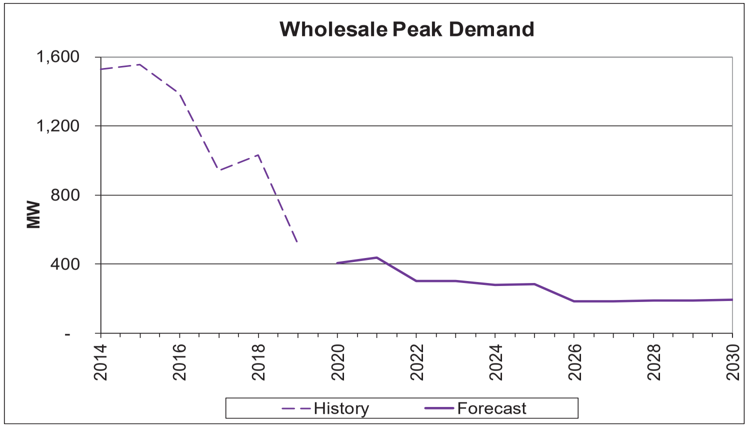

SPS Large C&I Sales (GWh)

Significant slowdown in mid-2020,
with some recovery in 2021

SPS System Peak Demand


Total Net Peak Demand
(Retail, Full Req Whls, and Partial Req Whls)


Retail Peak Demand


Wholesale Peak Demand

QUESTIONS & DISCUSSION

TOPICS FOR FUTURE MEETINGS

- Gas & Power Markets
- Coal Supply
- Energy Storage

NM IRP DETAILS

- Web Page -

  https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/2022_new_mexico_integrated_resource_plan

  ** Note: For the Service Area, click on New Mexico. At the bottom of the page click on the Public Advisory Meeting tab, then click on the date for the first public meeting*

- Resource Planning Contacts –
  - Bennie Weeks | Manager of Resource Planning & Bidding | Bennie.Weeks@xcelenergy.com
  - Ben Elsey | Resource Planning Analyst | Ben.R.Elsey@xcelenergy.com
  - Ashley Gibbons | Resource Planning Analyst | Ashley.Gibbons@xcelenergy.com
- Regulatory Contacts –
  - Linda Hudgins | Case Specialist II | *Linda.L.Hudgins@xcelenergy.com*
  - Mario Contreras | Rate Case Manager | *Mario.A.Contreras@xcelenergy.com*

SPS New Mexico 4th IRP Public Meeting

Date: March 23, 2021

Time: 10:00 AM – 12:00 PM Mountain Time

Location: Zoom Meeting

Xcel Energy®

Xcel Energy®

2021 SPS New Mexico Integrated Resource Plan: 4th Public Advisory Meeting

March 23, 2021

Topics For Discussion

- Coal Supply
- Tolk Station Water Supply
- Gas & Power Market Price Forecasting
- Questions and Discussion
- Next Meeting Topics
- Final Public IRP Meeting

COAL SUPPLY PRESENTATION

Dana Echter

Manager, Fuel Supply Operations

March 23, 2021

HARRINGTON STATION

Location: near Amarillo, Texas

- Three coal-fired units: ~1,050 net MW
- Coal sources
  - Low-sulfur Powder River Basin ("PRB") coal mines - North Antelope Rochelle, Antelope and Black Thunder
- Rail Transportation: Burlington Northern Santa Fe (BNSF)
- Trestle unloading system
- 2020 consumption: ~2.1 million tons
- All three units will be converted to gas no later than January 1, 2025

TOLK STATION

Location: near Muleshoe, Texas

- Two coal-fired units: ~1,082 net MW
- Coal sources
  - Low-sulfur Powder River Basin (“PRB”) coal mines - North Antelope Rochelle, Antelope and Black Thunder
- Rail Transportation: Burlington Northern Santa Fe (BNSF)
- Rotary unloading system
- 2020 consumption: ~1.1 million tons

SPS CONTRACT INFORMATION

TUCO, Inc.

- TUCO is a third-party supplier responsible for managing contracts with coal suppliers, rail transportation and coal handling.
- SPS purchases coal from TUCO at the plant bunkers
- Xcel Energy’s Fuel Supply Operations manages the TUCO contract
- The TUCO contracts expire on Dec 31, 2022. These may be extended to coincide with the conversion of Harrington to natural gas.

TUCO COAL CONTRACT INFORMATION

- Coal suppliers are Peabody Energy (North Antelope Rochelle), Cloud Peak Energy (Antelope) and Arch Coal (Black Thunder)
- Coal contracts are fixed price, term and quantity
- Coal supply agreements are short term and expire before the TUCO agreements

TUCO TRANSPORTATION CONTRACT INFORMATION

Transportation

- Tolk and Harrington served by BNSF Railway
- The Harrington rail agreement expires in Dec 2022
- The Tolk rail agreement expires in Dec 2022
- Include Mileage Based Fuel Surcharges

Railcars

- Railcars are provided by long-term lease held by TUCO and expire concurrently with the TUCO Coal Supply Agreements

POWDER RIVER BASIN

- Roughly 300mi x 100 mi
- USGS
  - 140 billion tons of resources in areas of most interest
  - 77 billion tons in Gillette Coalfield alone

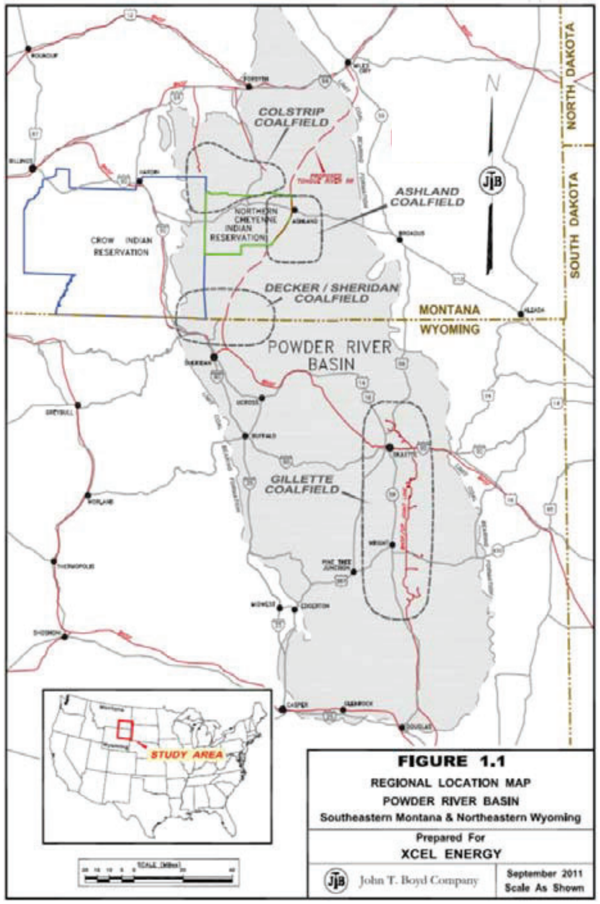
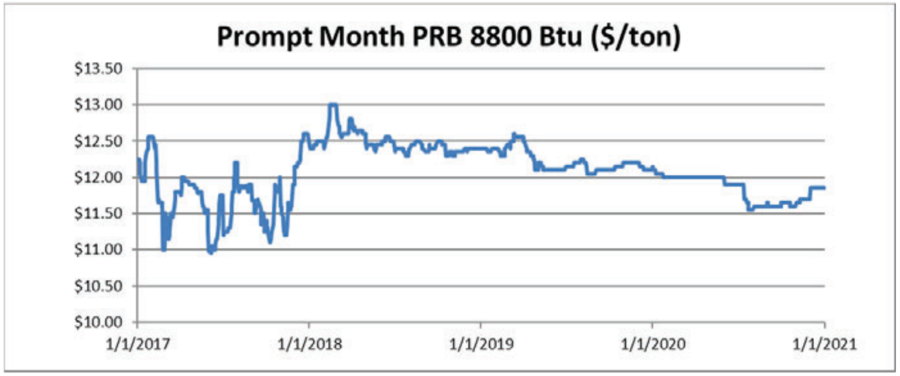


FIGURE 1.1
REGIONAL LOCATION MAP
POWDER RIVER BASIN
Southeastern Montana & Northeastern Wyoming
Prepared For
XCEL ENERGY
John T. Boyd Company
September 2011
Scale As Shown

PURCHASE STRATEGY

- Current market is approximately $11.90/ton for 8,800 Btu/lb PRB coal FOB mine



- Keep relatively large open position to be able to react to changes in system operations
- Target is by December, purchase ~60% of upcoming year requirements, ~30% for 2nd year and ~15% for 3rd year.

Xcel Energy®

TOLK STATION WATER SUPPLY

Richard L. Belt, P.E., P.H. – Director, Chemistry & Water Resources

March 23, 2021

Definitions & Background

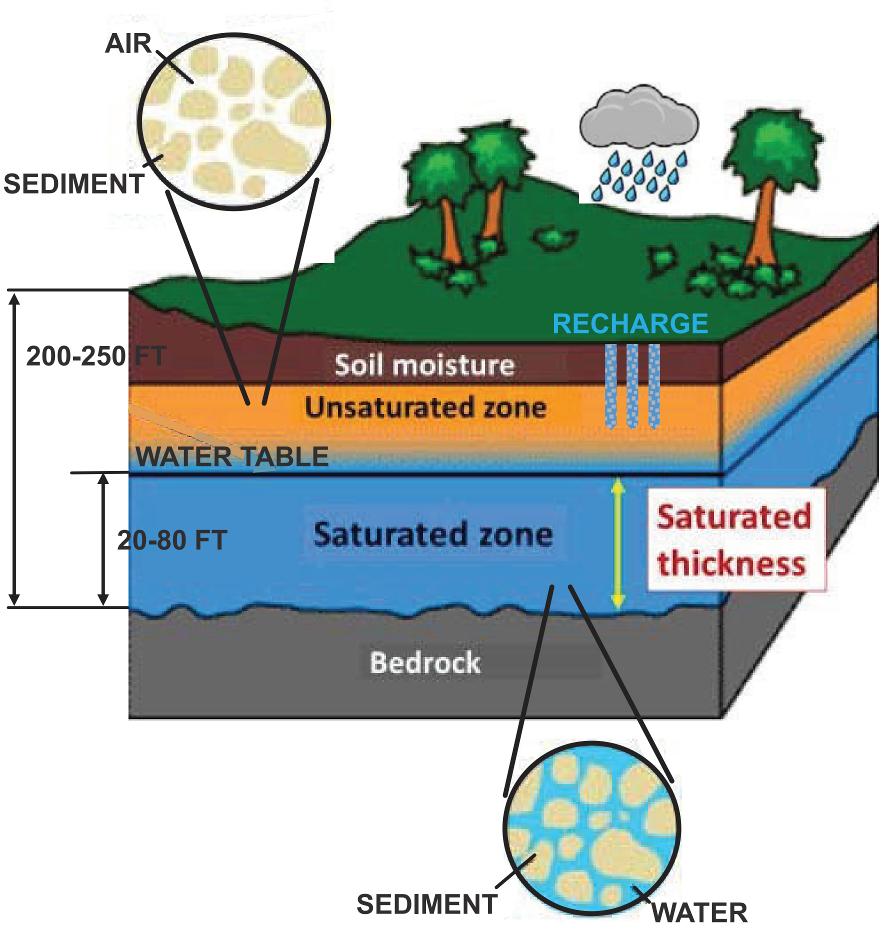
An **aquifer** is a geologic formation which is saturated with water.

The **water table** divides the saturated & unsaturated zones.

Saturated thickness is the thickness of the aquifer from bedrock to water table.

Recharge is excess water which may percolate to the saturated zone. There is very little aquifer recharge in this part of the Ogallala Aquifer.

High Plains Underground Water District No. 1 is abbreviated as HPWD, throughout.



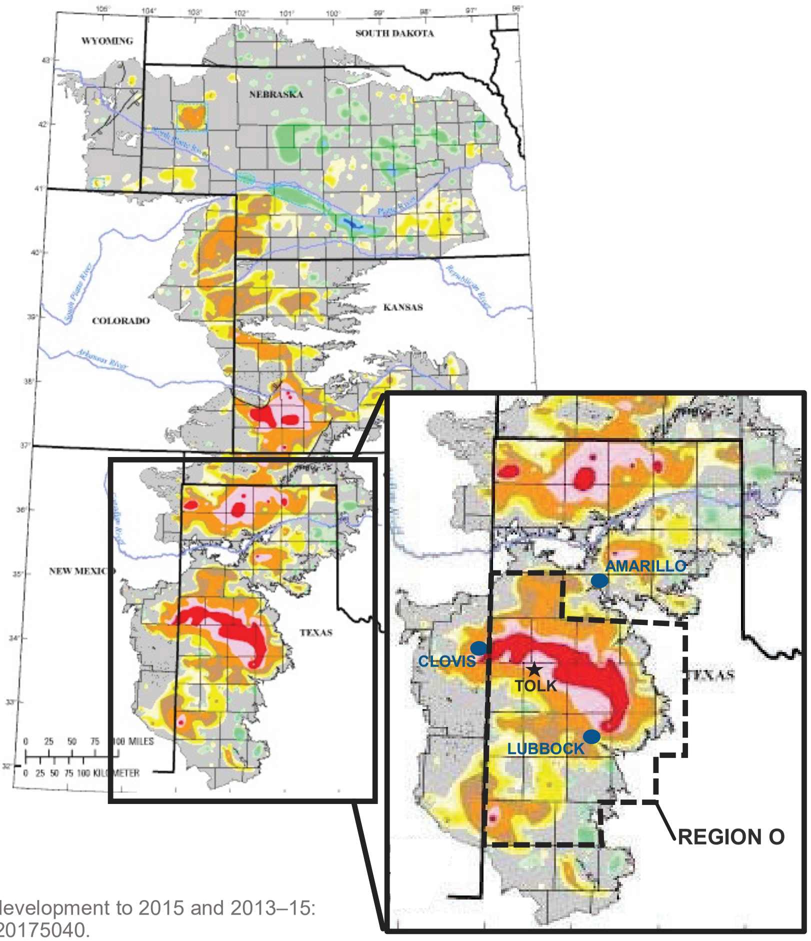
Ogallala Aquifer Overview

The **Ogallala Aquifer** is one of the largest freshwater aquifers in the world, formed 2M to 6M years ago.

Water filled the aquifer following the most recent ice age and probably earlier.

The Ogallala underlies 8 states and 27% of irrigated land in the U.S.

The aquifer supplies more than 80% of the potable water for 2.3M people residing and working in the lands overlying it.

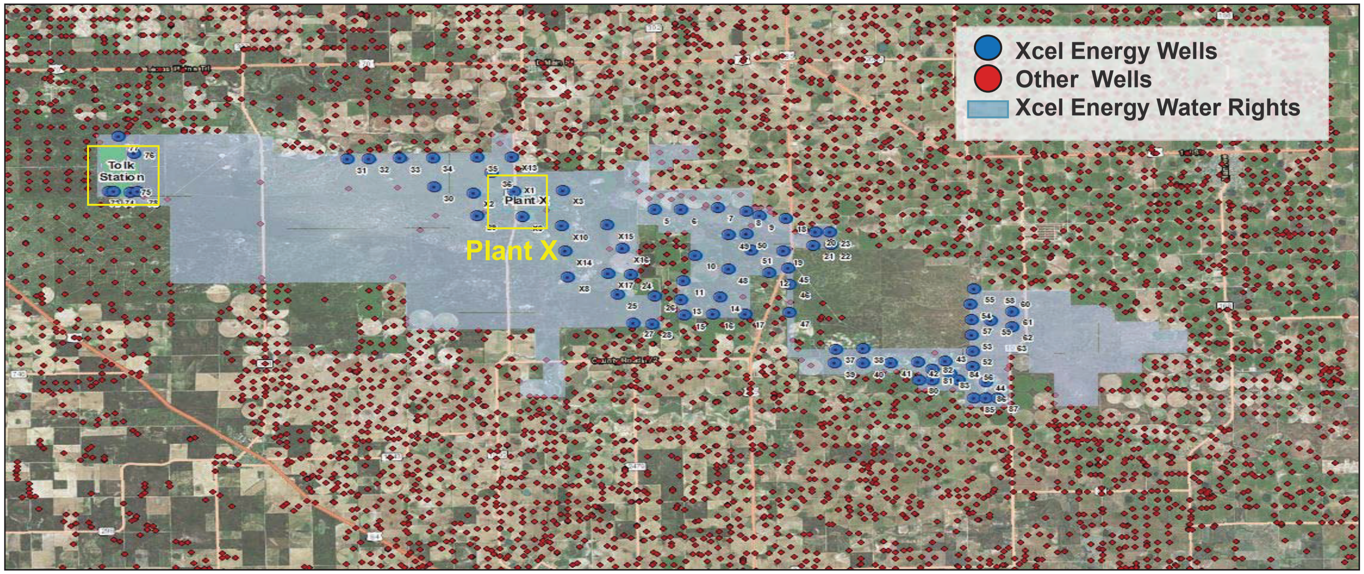


McGuire, V.L., 2017, Water-level and recoverable water in storage changes, High Plains aquifer, predevelopment to 2015 and 2013–15: U.S. Geological Survey Scientific Investigations Report 2017–5040, 14 p., https://doi.org/10.3133/ sir20175040.

Competition for Water

Wellfield overview:

- 50K ac wellfield
- 89 production wells
- ~30 miles from furthest well to Tolk Station



High Plains Underground Water District No. 1 (HPWD) groundwater production rules limit all users to 18-inches per acre per year.

Tolk water use in 2020 equal to approximately 1.29 inches per acre.

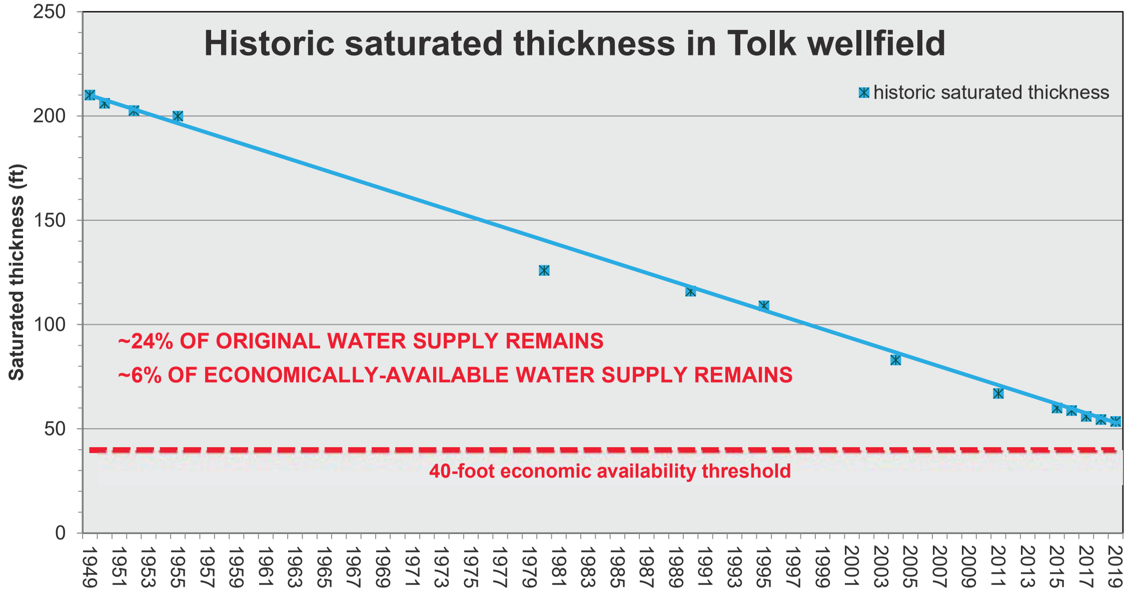
Tolk Wellfield History

In Lamb County (HPWD, 2020):

- 50-ft average saturated thickness
- 13.7-ft average decline since 2010

Texas Water Development Board Region O planning area:

- 1.7 million acre-foot annual shortage by 2020
- 2.1 million acre-foot annual shortage by 2070



Groundwater Production Issues

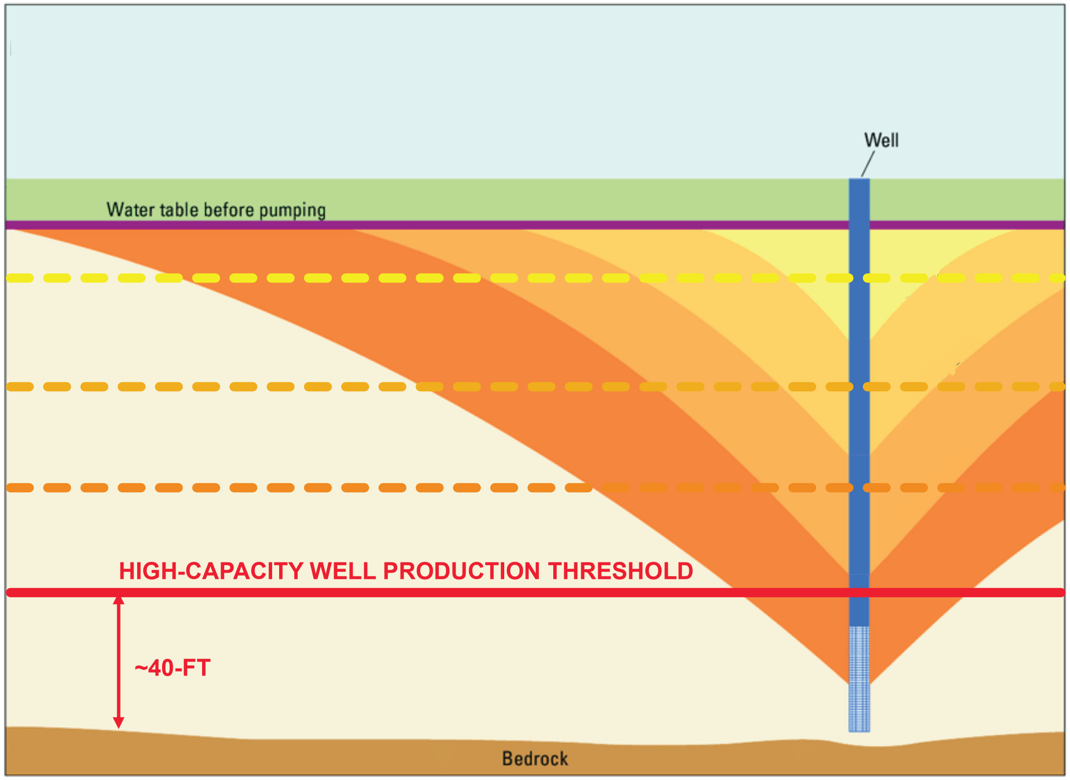
Each well creates a cone of depression when pumped.

Over time, the cone gets deeper until the well is inoperable.

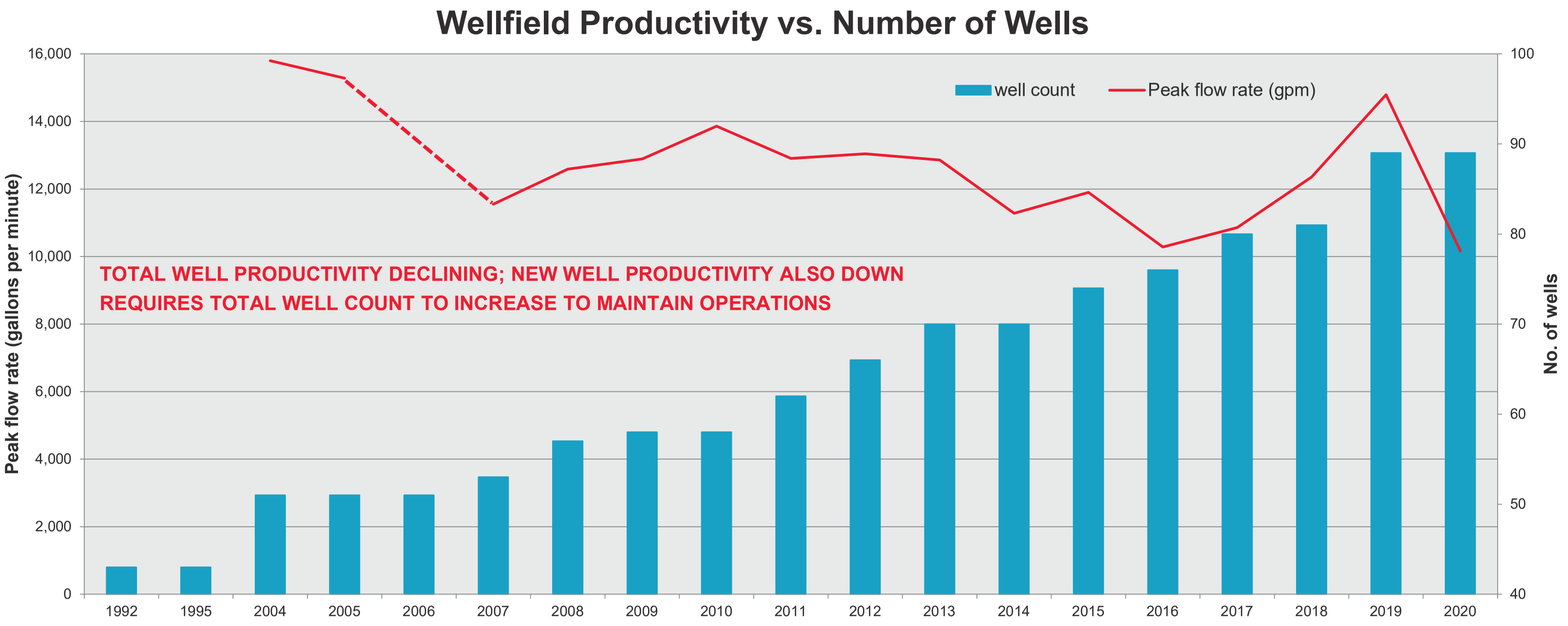
Multiple wells operating nearby create overlapping cones, drawing down the regional water table.

At about 40-ft, high-capacity wells become ineffective => multiple low-capacity wells needed to replace

Milkshake analogy.



Wellfield Decline



Wellfield Productivity vs. Number of Wells

TOTAL WELL PRODUCTIVITY DECLINING; NEW WELL PRODUCTIVITY ALSO DOWN
REQUIRES TOTAL WELL COUNT TO INCREASE TO MAINTAIN OPERATIONS

Tolk Station Plan

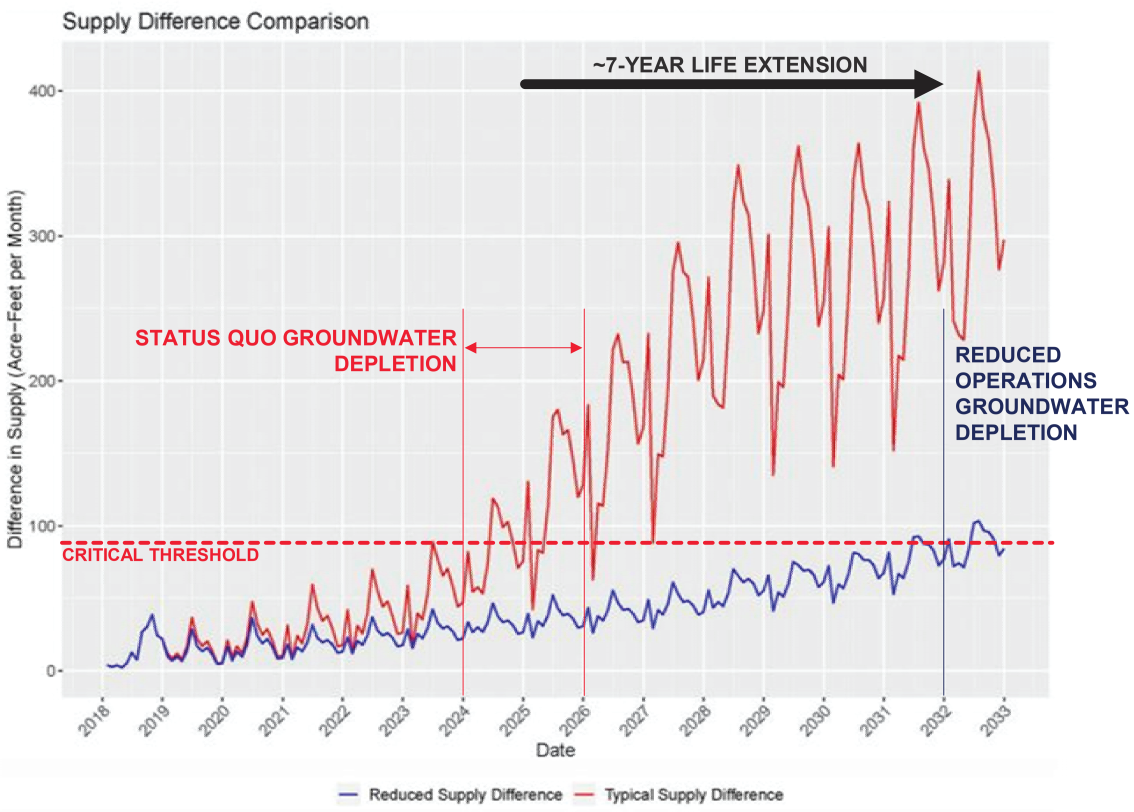
SPS implemented seasonal generation operations in 2019 to extend plant life to ~2032.

Synchronous condensers installed in 2020.

Annual groundwater model update to monitor impact of Tolk actions & 3rd party water users.

Remaining model uncertainty:

- Water use by 3rd parties (agriculture)
- Future weather (drought)
- Future electric system requirements



GAS AND POWER MARKET PRICE FORECASTING

March 23, 2021

Natural Gas Forecasting Methodology

Xcel Energy derives the forecast of natural gas prices semi-annually in spring/fall

Henry Hub Forecast is an average of three consultants’ long-term forecasts and the current NYMEX strip

The forecast is fully market based for the first few years, then it transitions into blending NYMEX with the consultants’ long-term forecasts as follows:

Period	NYMEX	IHS	S&P Global	Wood Mackenzie
Balance of the year + 2 years	100%	0%	0%	0%
Years 3 and Beyond	25%	25%	25%	25%
	10 yr trendline extension			

Consultants’ Modeling and Assumptions Differ

- Natural gas supply and demand
- Coal retirements
- Renewable penetration
- Technology improvements
- LNG exports
- Gas pipelines

Natural Gas Delivered Price

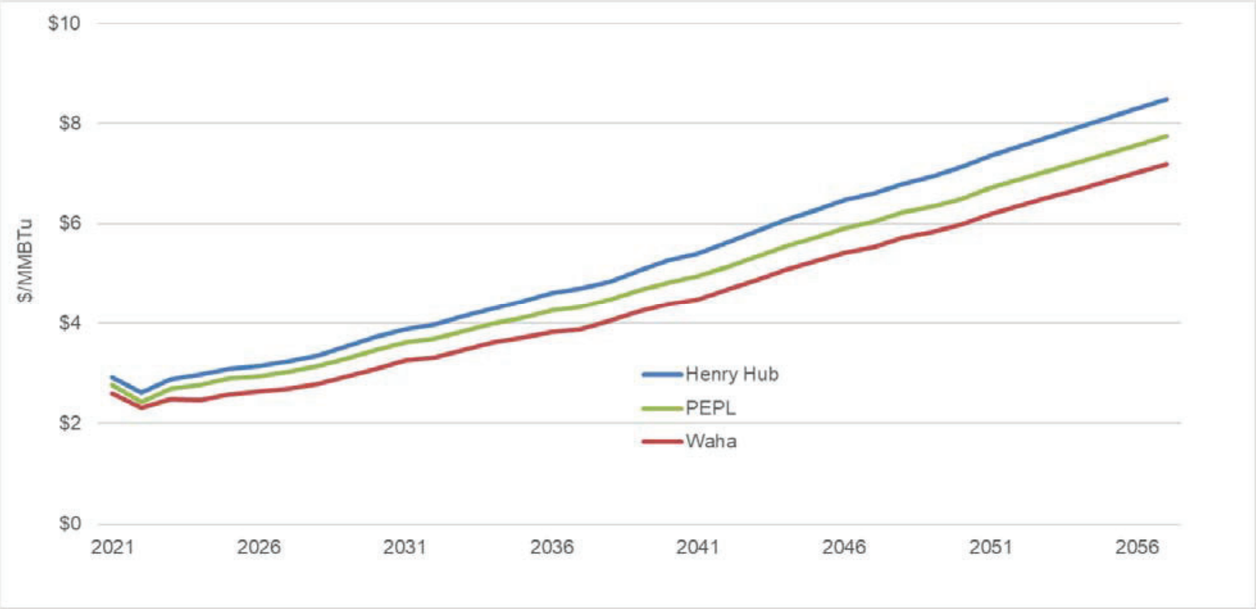
Basis differential is the difference in the gas price at a given hub compared to a benchmark location (Henry Hub)

Henry Hub is adjusted for regional basis differentials and specific delivery costs for each generating unit to develop model inputs

- Data source for basis: IHS Markit, S&P Global and Wood Mackenzie

Recent Natural Gas Price Forecasts

(Fall 2020)



Electricity Market Prices

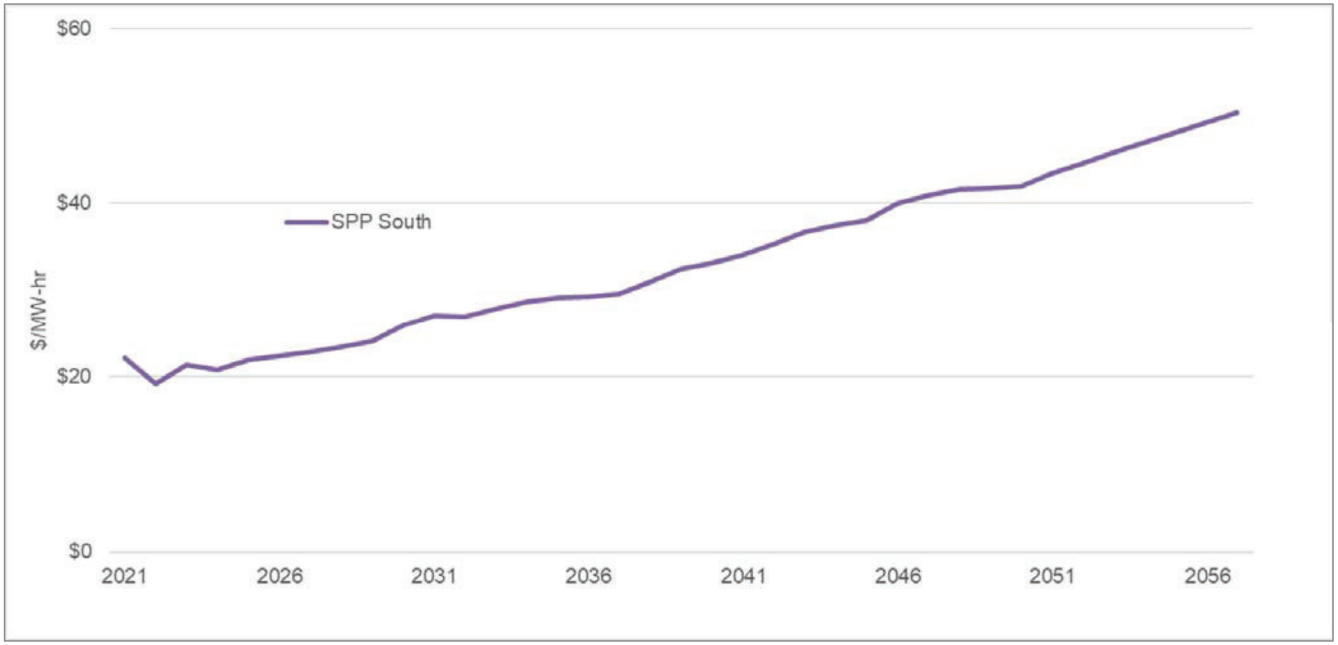
To derive the forecast of monthly on and off-peak prices, the company uses a simple average of long-term implied heat rate forecasts provided by:

- IHS, S&P Global and Wood Mackenzie

The implied heat rates are multiplied by the gas price at a near location to determine the on and off-peak prices ($/MWh)

Recent Electricity Forecast

(Fall 2020)



QUESTIONS & DISCUSSION

TOPICS FOR THE FINAL MEETING

- Accreditation of Energy Storage
- Energy Storage
- GIA Issues

NM IRP DETAILS

- Web Page -

  https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/2022_new_mexico_integrated_resource_plan

  ** Note: For the Service Area, click on New Mexico. At the bottom of the page click on the Public Advisory Meeting tab, then click on the date for the first public meeting*

- Resource Planning Contacts –
  - Bennie Weeks | Manager of Resource Planning & Bidding | Bennie.Weeks@xcelenergy.com
  - Ben Elsey | Resource Planning Analyst | Ben.R.Elsey@xcelenergy.com
  - Ashley Gibbons | Resource Planning Analyst | Ashley.Gibbons@xcelenergy.com
- Regulatory Contacts –
  - Linda Hudgins | Case Specialist II | *Linda.L.Hudgins@xcelenergy.com*
  - Mario Contreras | Rate Case Manager | *Mario.A.Contreras@xcelenergy.com*

SPS New Mexico 5th IRP Public Meeting

Date: May 13, 2021

Time: 10:00 AM – 12:00 PM Mountain Time

Location: Zoom Meeting

Xcel Energy®

Xcel Energy®

2021 SPS New Mexico Integrated Resource Plan: 5th Public Advisory Meeting

May 13, 2021

Topics For Discussion

- Energy Storage
- Generator Interconnection Agreement Issues
- Questions and Discussion

Xcel Energy®

Energy Storage Overview

SPS New Mexico IRP Public Advisory Meeting

May 13, 2021

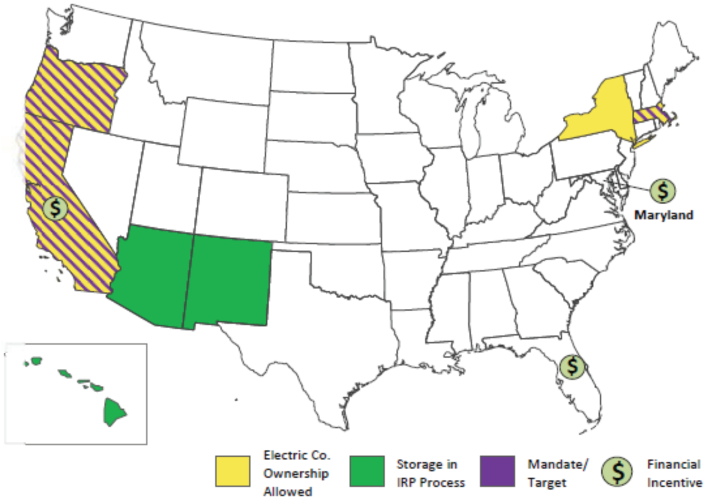
National Storage Policy Trends

Legislative:

- Climate Change Mandates/Target
- Tax Credits/Incentives
- Study/Investigative Proceeding
- Ownership Rules
- Clean Peak Standards

Regulatory/Rate Design:

- Resource Planning/Procurement Requirement
- Grid Modernization/Distribution Planning Proceeding
- Interconnection Rules
- Value of Storage/DER
- Demand Charges



- **RTO/ISO Activity:** FERC NOPR on storage participation in markets and DER Aggregation, MISO Energy Storage Task Force
- **National Stakeholders:** Energy Storage Association, Interstate Renewable Energy Council (IREC), Advanced Energy Economy, Energy Freedom Coalition of America (EFCA)

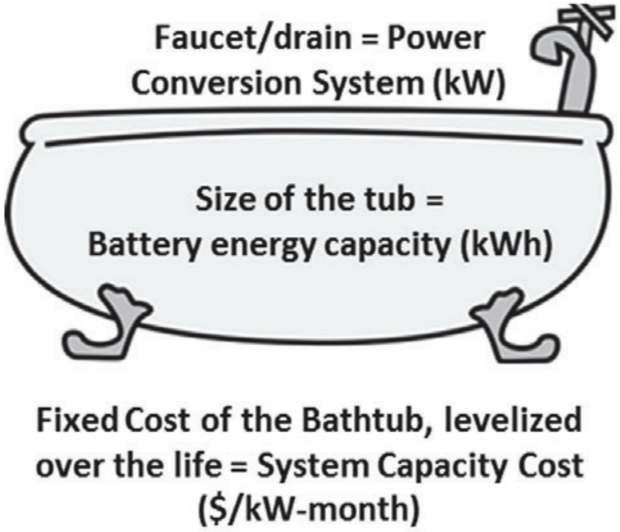
Source: Edison Electric Institute

What's Changed Since 2018?

- There are technologies that are not commercially feasible today that are needed to achieve a carbon-free generation fleet by 2045 (pursuant to Energy Transition Act)
- Degree to which storage can contribute to decarbonization is weighted on par with the economic and reliability benefit to the grid system
- Storage will be able to capture more carbon-free electricity that would otherwise be curtailed to support grid balancing
- Longer duration storage will be needed to enable greater penetrations of variable renewable energy – More storage with >10 hours and up to seasonal scale (>100 hours duration)
- Shorter duration storage is still needed for faster grid response applications
- Several new advanced storage technologies are becoming commercially available in the near to mid-term

Energy Storage as a Bathtub

- The size of the tub (or reservoir in the case of a pumped hydro facility), and therefore how much water or energy it can store, determines the **kWh (energy storage capacity)**
- The Power Conversion System works like the faucet/drain in the tub. It determines how quickly the tub will drain and then refill, and therefore determines the **kW (power)** metric
- The cost of the tub as a resource can be described in terms of **$/kW-month (system capacity cost)**
- Duration is one of the most important drivers of the value of a particular storage system **(hours)**



Faucet/drain = Power Conversion System (kW)

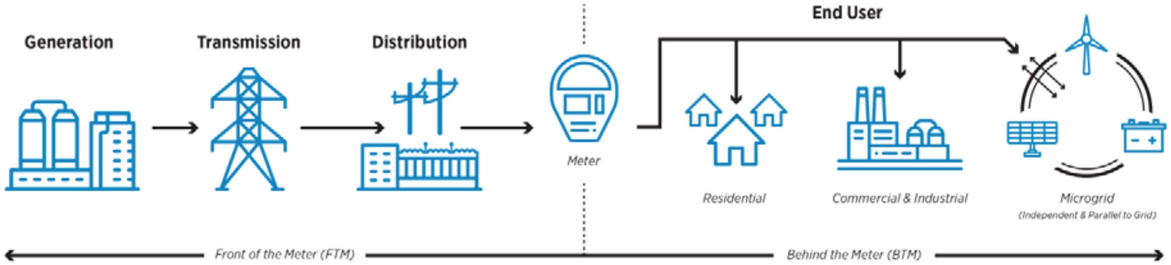
Size of the tub = Battery energy capacity (kWh)

Fixed Cost of the Bathtub, levelized over the life = System Capacity Cost ($/kW-month)

Stored Energy (kWh) = Power (kW) * Discharge time (hrs)

Why Energy Storage?

Energy storage can be deployed in all parts of the grid, and has applications in all parts of the value chain.



Enhance Utility Operations
- Alleviate high energy prices through time shifts
- Reduce the need for new generation
- Reduce Carbon Emissions

Provide Grid Support
- Regulate frequency
- Reduce spinning, non-spinning and supplemental reserve requirements
- Voltage support
- Black start electricity restoration

Optimize Power System
- Defer transmission and distribution upgrades
- Relieve electricity congestion

Enhance Customer Experience
- Higher power quality and reliability
- Retail electric energy time shift

FERC REGULATED

STATE REGULATED T&D

END USE

Source: Adapted from DOE/EPRI Handbook, EEI (graphic)

What is Energy Storage?

Definition

- Technology capable of storing previously generated electric energy and releasing it at a later time.
- Can occur as potential, kinetic, chemical, or thermal energy.
- Release of energy can be in forms that include electricity, gas, thermal energy and other energy carriers.
- Can be deployed in all parts of the grid – helps to enable a smarter, stronger, cleaner, and more reliable energy grid for all customers.

Asset Categories

- Electric generation asset
- Transmission asset
- Distribution asset
- DSM asset

Uses

- Capacity
- Flexibility
- Reliability/resiliency
- Microgrids and community projects

Technologies

Electrochemical Storage: Includes advanced chemistry batteries and capacitators – sodium sulfur, lead acid, lithium ion, metal air, solid state, etc.

Flow batteries: Energy is stored in electrolyte solution for longer life cycle and quick response

Hydrogen: Hydrogen or hydrogen carriers are compressed or stored as liquids to provide long duration energy reserves, carbon-free fuels, and/or feedstocks for other industries

Compressed air energy storage: Compressed air is used to create a potent energy reserve

Thermal: Heat and cold are captured to create energy on demand

Pumped hydro power: Large scale reservoirs of energy are created with water

Storage Technologies

Technology	Benefits	Challenges	Applications
Lithium-Ion Battery	• Energy density • Power density	• Cycle life constraints • Safety concerns	Peak shaving, T&D investment deferral, renewable integration, ancillary services
Lead Acid Battery	• Familiar • Inexpensive	• Relatively low energy & power density • Poor cycle life • Often requires maintenance • Environmental impacts	Best suited for relatively limited-cycle applications requiring shallow depth of discharge such as backup power and limited peak shaving.
Sodium Sulfur Battery	• High energy density	• High temps required • Limited power capabilities	Peak shaving, T&D investment deferral, renewable integration
Flow Batteries	• Decouple power (reactor size) from energy (tank size) • Improved cycle life	• Low energy density • Added components with pumping	Peak shaving, T&D investment deferral, renewable integration, ancillary services
Flywheels	• Fast Response • High Power	• Low Energy/duration • High self discharge rates	Power quality, frequency regulation, wind generation stabilization
Compressed Air Energy Storage (CAES)	• Reliable bulk storage	• Geologically limited	Capacity/energy services, ancillary services, renewable integration
Pumped hydro	• Reliable Bulk Storage	• Geographical limits • Capital intensive	Capacity/energy services, ancillary services, renewable integration

Carbon-Free Innovations Further Enabled through External Engagements

EPRI & GTI: LCRI Sponsors

Others | EIP, DOE, Universities

*

Funding & Membership	Research	Research

* **Energy Impact Partners (EIP) – Summary of Funds Managed**

EIP Energy Impact Fund (EIF):
Energy Impact Partners (EIP) is a global investment platform leading the transition to a sustainable energy future. EIP brings together entrepreneurs and the world's most forward-looking utilities and operating companies to advance innovation. With over $1.5 billion in assets under management, EIP invests globally across venture, growth, credit and infrastructure – and has a team of more than 50 professionals based in its worldwide offices.

EIP Deep Decarbonization Frontier Fund (Frontier Fund):
Leveraging the industry and investing experience of the EIF, the Frontier Fund focuses on revolutionary technologies driving to net-zero emissions and mitigating climate change. This fund's target sectors include: zero carbon generation, carbon capture, hydrogen, energy storage, materials and industry, and transportation electrification.

EIP Elevate Diversity Impact Fund (Elevate Fund):
The Elevate Fund aims to increase diversity in the energy industry by investing in innovative companies founded or run by under-represented talent (e.g., black, latinx, women, LGQBT+, etc.). Elevate will help equalize the typically disproportional access to the venture capital ecosystem, as well as offer opportunities to positively affect disadvantaged communities.

Why is This Important in the Future?

Grid needs

Carbon-free generation resources

Integration of variable carbon-free resources

Grid operations and grid modernization

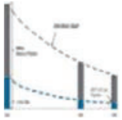
Resiliency improvements

✚

Market and policy drivers

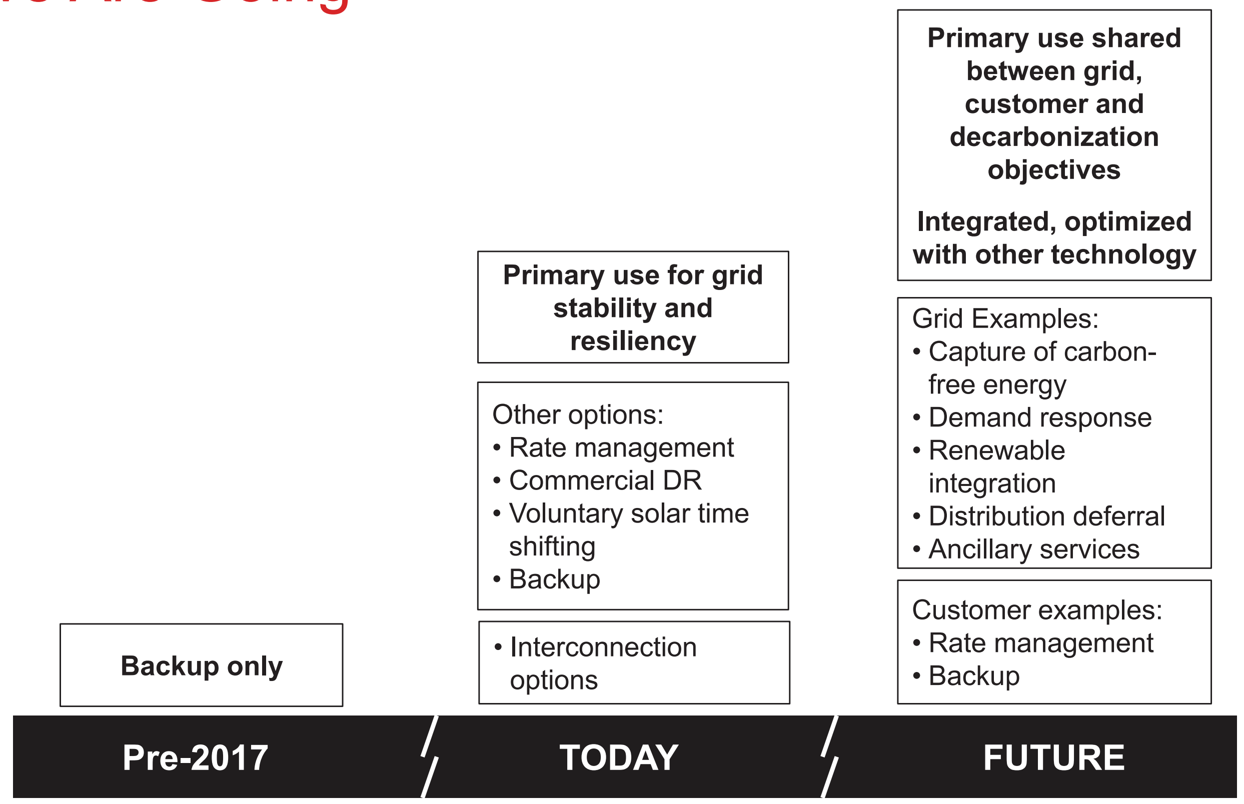
Policy changes

Technology advances



Cost declines

Where We Are Going



Pre-2017

Backup only

TODAY

Primary use for grid stability and resiliency

Other options:
- Rate management
- Commercial DR
- Voluntary solar time shifting
- Backup

- Interconnection options

FUTURE

Primary use shared between grid, customer and decarbonization objectives

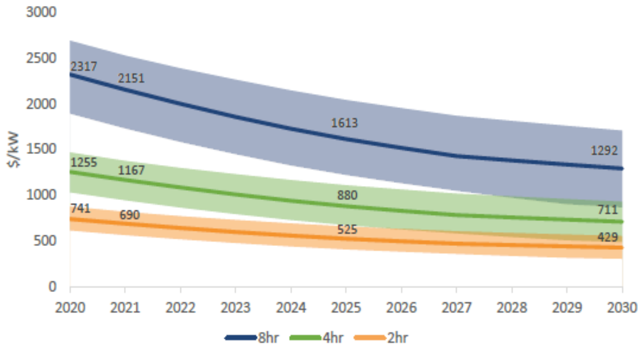
Integrated, optimized with other technology

Grid Examples:
- Capture of carbon-free energy
- Demand response
- Renewable integration
- Distribution deferral
- Ancillary services

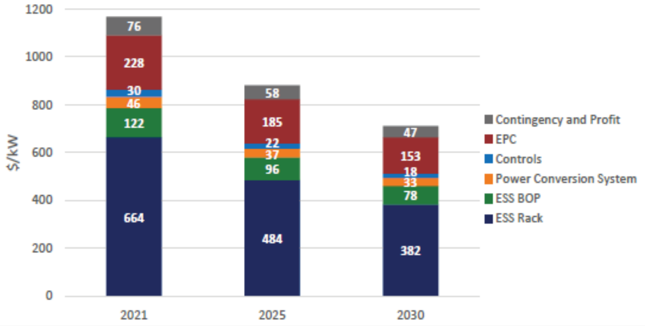
Customer examples:
- Rate management
- Backup

Lithium Ion BESS Installed Cost Projections

Installed Cost Projection Range for a 100 MW Lithium Ion System, 2020$



Installed Cost Projection Breakdown for a 100MW, 4-hour Lithium Ion System, 2020$



Lithium ion installed costs are projected to decrease by over 40% by 2030. The top figure illustrates projected installed cost for a 100 MW system with upper and lower bounds based on the potential differences in costs captured in the bottom figure. The longer duration systems have a larger range due to the cost sensitivities of the battery portion which makes up a larger percentage of the installed cost.

The bottom figure illustrates an example breakdown of installed cost for a 100MW, 4hr system through 2030. Cost reductions will likely be accomplished across all major cost categories.

Battery cost declines are based on electric vehicle battery pack cost projections with adjustments for stationary racks. The gap between electric vehicle packs and stationary racks is assumed to decrease over time as stationary energy storage grows in manufacturing scale. Battery cost projections are lower than previous EPRI estimates which included some uncertainty around material prices. However, in the last two to three years battery manufacturers have adjusted their formulas and managed their supply chains to minimize impact of changes in the metals markets.

Xcel Energy®

ACCREDITATION OF ENERGY STORAGE IN THE SOUTHWEST POWER POOL

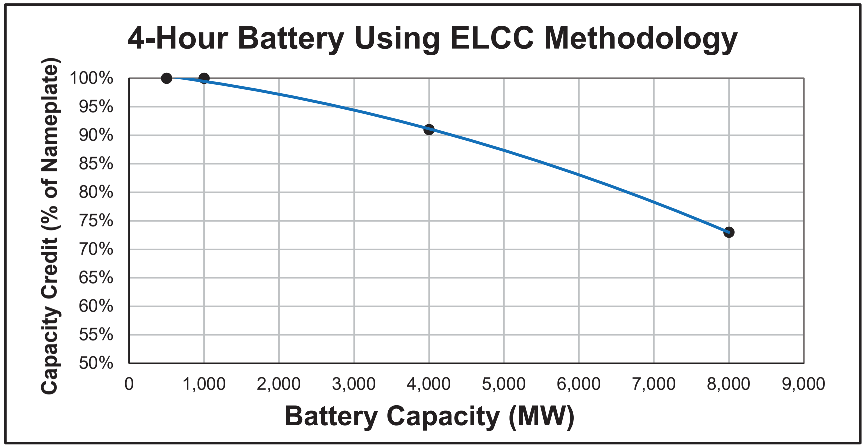
Ashley Gibbons | Resource Planning Analyst

May 13, 2021

SPP PROPOSED ACCREDITATION OF STANDALONE ENERGY STORAGE RESOURCES (ESRs)

Beginning 2023

- SPP will implement the Effective Load Carrying Capability (“ELCC”) methodology for determining accredited capacity for standalone ESRs
- Batteries with a 4-hour or greater duration will initially qualify for 100% accredited capacity
- The amount of accredited capacity for energy storage resources will decrease as the penetration of energy storage increases across the SPP footprint (e.g. accredited capacity is reduced to 73% at 8,000MW of ESR)
- SPP will update ELCC study every two years



Nameplate Battery Size (MW-hour)	Nameplate Battery Duration	Nameplate Battery Capacity (MW)	Capacity value evaluated for ELCC Study (MW)
120 MW-hour	2 -hour	60MW	30MW
120 MW-hour	4-hour	30MW	30MW
120 MW-hour	6-hour	20MW	20MW
120 MW-hour	8-hour	15MW	15MW

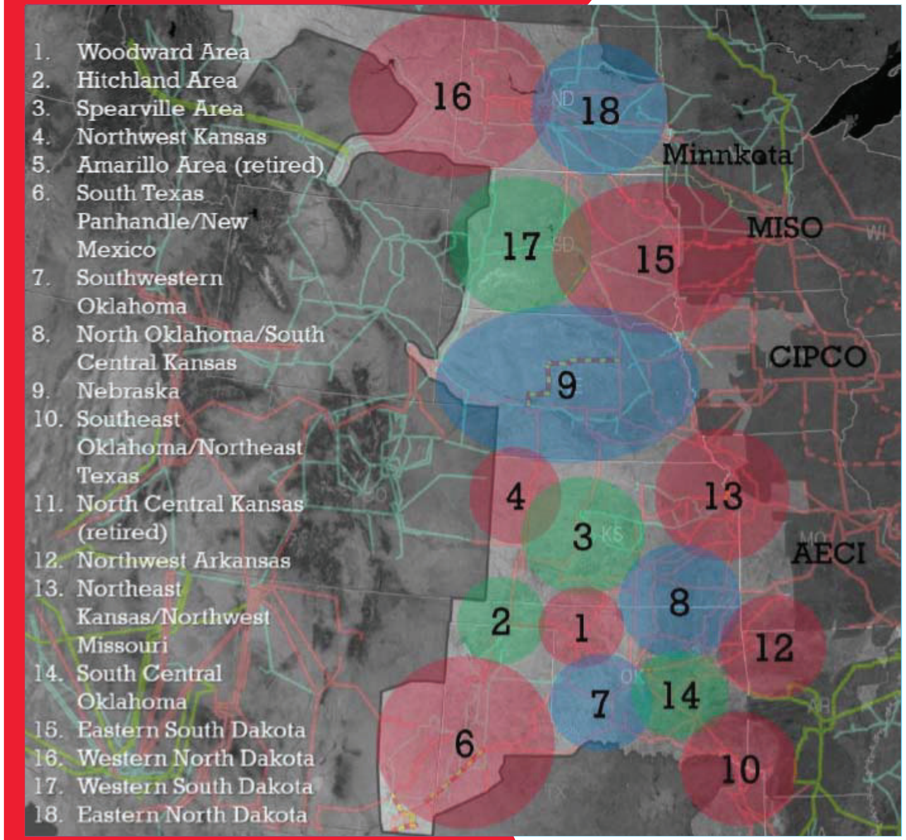
QUEUED UP?
CLEARING THE SPP DISIS BACKLOG

Kevin Pera, P.E. | Transmission Analyst

May 13, 2021

MOVING THROUGH THE QUEUE

Past:	**Plenty of headroom in SPS territory**
Present:	**Clearing out the MW**
Future (??):	**Changing study structures**



HOW DID WE GET HERE?

1. Old way—individual requests, studied in queue order

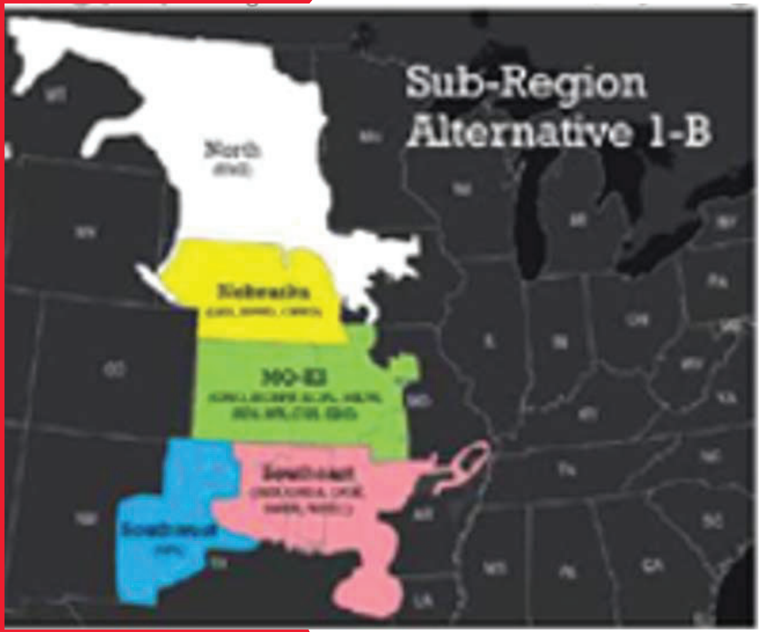
2. DISIS (2009-pres.)—clusters of requests

   Same cluster—equally-queued

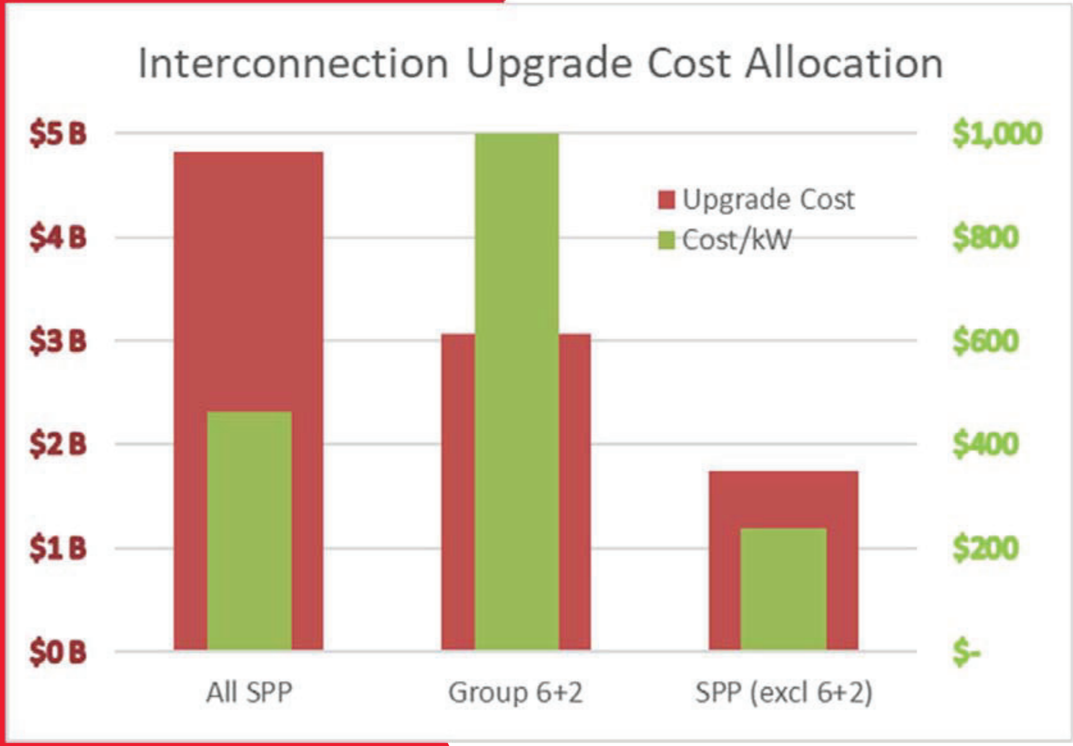
   ←Studied in Groups

3. Each group exports all generation

17-2 GROUP REDUCTION



- SPP North
- SPP North Central
- SPP Central
- SPP Southeast
- SPP Southwest



UPGRADES—THE MAIN ISSUE

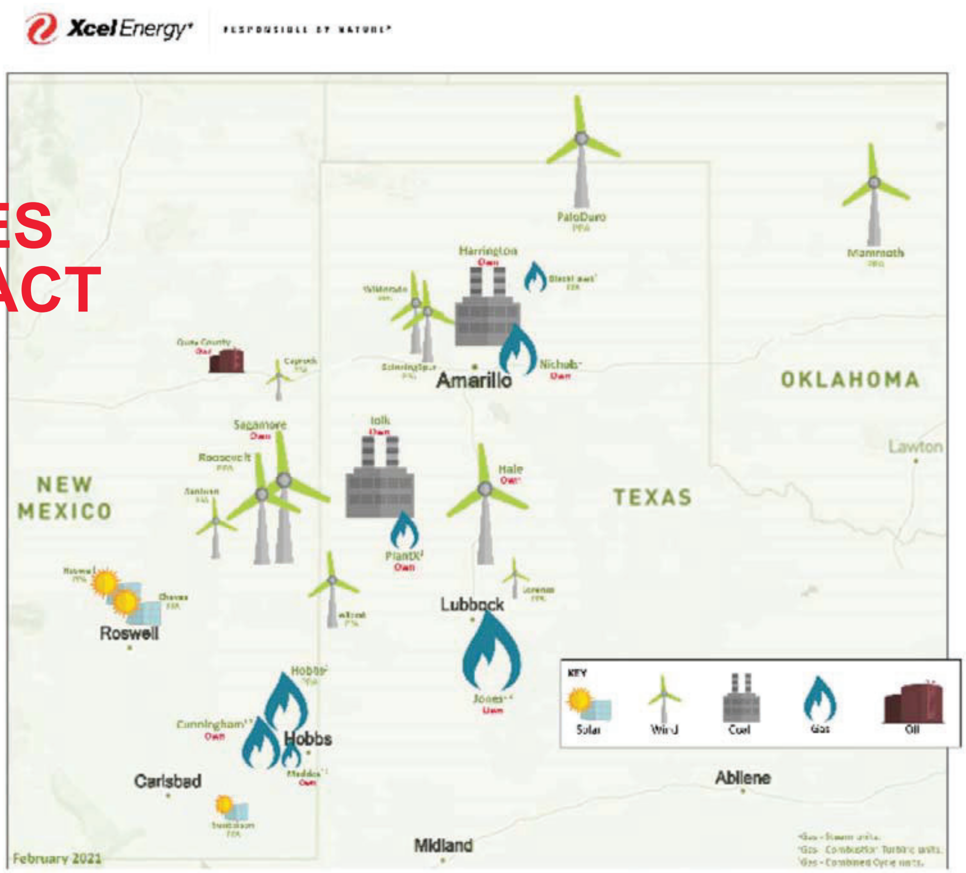
1. All active requests and those with a GIA remain in future studies
2. Too many megawatts—too many upgrades
3. MW expire—SPP reconsiders their upgrades

WHERE ARE WE NOW?

1. *GENERAL*
   - SPP working on 17-1, just announced 16-2 restudy
2. *SPECIFIC*
   - *Decision Point 2 (DP2)*
   - *$930 million in at-risk deposits due today (May 13th)*
   - *$500 million in Group 6, to cover $2.5 billion in upgrades*

HOW DOES THIS IMPACT SPS?

1. *Opportunities*
2. *Cost*
3. *Timing*



Xcel Energy®

© 2021 Xcel Energy

QUESTIONS & DISCUSSION

NM IRP DETAILS

- Web Page -

  https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/2022_new_mexico_integrated_resource_plan

  ** Note: For the Service Area, click on New Mexico. At the bottom of the page click on the Public Advisory Meeting tab, then click on the date for the first public meeting*

- Resource Planning Contacts –
  - Bennie Weeks | Manager of Resource Planning & Bidding | Bennie.Weeks@xcelenergy.com
  - Ben Elsey | Resource Planning Analyst | Ben.R.Elsey@xcelenergy.com
  - Ashley Gibbons | Resource Planning Analyst | Ashley.Gibbons@xcelenergy.com
- Regulatory Contacts –
  - Linda Hudgins | Case Specialist II | *Linda.L.Hudgins@xcelenergy.com*
  - Mario Contreras | Rate Case Manager | *Mario.A.Contreras@xcelenergy.com*

Xcel Energy®

Southwestern Public Service Company
Applicable Electric Utility IRP Rule Requirements and Where Addressed in SPS's Filing

NMAC	Requirement	Where Addressed
17.7.3.9	**INTEGRATED RESOURCE PLANS FOR ELECTRIC UTILITIES**	
A.	Initial filings. Utilities with greater than 200,000 New Mexico retail customers shall file 15 months after the effective date of this rule. Utilities with less than 200,000 New Mexico retail customers shall file 27 months after the effective date of this rule. An original and fourteen copies of the IRP shall be filed with the commission.	IRP filed on July 16, 2021
B.	Contents of IRP for electric utilities. The IRP submitted by an electric utility shall contain the utility's New Mexico jurisdictional:	
1.	description of existing electric supply-side and demand-side resources;	Section 3
2.	current load forecast as described in this rule;	Section 4
3.	load and resources table;	Section 5
4.	identification of resources options;	Section 6
5.	description of the resource and fuel diversity;	Section 7
6.	identification of critical facilities susceptible to supply-source or other failures;	Section 3
7.	determination of the most cost-effective resource portfolio and alternative portfolios;	Section 7
8.	description of public advisory process;	Section 8
9.	action plan; and	Section 9
10.	other information that the utility finds may aid the commission in reviewing the utility's planning processes.	
C.	Description of existing resources. The utility's description of its existing resources used to serve its jurisdictional retail load at the time the IRP is filed shall include:	
1.	name(s) and location(s) of utility-owned generation facilities;	Table 3-1
2.	rated capacity of utility-owned generation facilities;	Table 3-1
3.	fuel type, heat rates, annual capacity factors and availability factors projected for utility-owned generation facilities over the planning period;	Table 3-1 (also included in Encompass files provided under Protective Order)
4.	cost information, including capital costs, fixed and variable operating and maintenance costs, fuel costs, and purchased power costs;	Table 3-1; Appendix A
5.	existing generation facilities' expected retirement dates;	Table 3-1
6.	amount of capacity obtained or to be obtained through existing purchased power contracts or agreements relied upon by the utility, including the fuel type, if known, and contract duration;	Section 3; Table 3-2
7.	estimated in-service dates for utility-owned generation facilities for which a certificate of public convenience and necessity (CCN) has been granted but which are not in-service;	Section 3
8.	amount of capacity and, if applicable, energy, provided annually to the utility pursuant to wheeling agreements and the duration of such wheeling agreements;	Section 3
9.	description of existing demand-side resources, including	Section 3
a.	demand-side resources deployed at the time the IRP is filed; and	Section 3
b.	demand-side resources approved by the commission, but not yet deployed at the time the IRP is filed; information provided concerning existing demand-side resources shall include, at a minimum, the expected remaining useful life of each demand-side resource and the energy savings and reductions in peak demand, as appropriate, made by the demand-side resource;	Section 3
10.	Description of each existing and approved energy storage resource, to include, at a minimum, the expected remaining useful life of the resource, its maximum capacity and dispatch characteristics, and operating costs;	Section 3
11.	reserve margin and reserve reliability requirements (*e.g.* FERC, power pool, etc.) with which the utility must comply, and the methodology used to calculate its reserve margin;	Section 3
12.	existing transmission capabilities:	
a.	the utility shall report its existing, and under-construction, transmission facilities of 115 kV and above, including associated switching stations and terminal facilities; the utility shall specifically identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of supply-side resources;	Section 3; Appendix B; Appendix C
b.	the utility shall describe all transmission planning or coordination groups to which it is a party, including state and regional transmission groups, transmission companies, and coordinating councils with which the utility may be associated;	Section 3
13.	environmental impacts of existing supply-side resources:	
a.	the utility shall provide the percentage of kilowatt-hours generated by each fuel used by the utility on its existing system, for the latest year for which such information is available;	Figure 3F.3
b.	to the extent feasible, for each existing supply-side resource on its system, the utility shall present emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury;	Table 3-8

Southwestern Public Service Company
Applicable Electric Utility IRP Rule Requirements and Where Addressed in SPS's Filing

NMAC	Requirement	Where Addressed
c.	to the extent feasible, for each existing supply-side resource on its system, the utility shall present the water consumption rate.	Table 3-8
14.	a summary of back-up fuel capabilities and options.	Section 3
D.	Current load forecast.	
1.	The utility shall provide a load forecast for each year of the planning period; the load forecast shall incorporate the following information and projections:	Section 4; Appendices D, E, & F
a.	annual sales of energy and coincident peak demand on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states;	Section 4; Appendix D
b.	annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system;	Section 4; Appendix D
c.	weather normalization adjustments;	Section 4; Appendix D
d.	assumptions for economic and demographic factors relied on in load forecasting;	Section 4; Appendix D
e.	expected capacity and energy impacts of existing and proposed demand-side resources; and	Section 4; Appendix D
f.	typical historic day or week load patterns on a system-wide basis for each major customer class.	Section 4; Appendix E
2.	The utility shall develop base-case, high-growth and low-growth forecasts, or an alternative forecast that provides an assessment of uncertainty (*e.g.*, probabilistic techniques).	Section 4; Appendix D
3.	Required detail.	
a.	The utility shall explain how the demand-side savings attributable to actions other than the utility-sponsored demand-side resources for each major customer class are accounted for in the utility's load forecast and the effect, as appropriate, on its load forecast of the utility-sponsored demand-side resources on each major customer class.	Section 4; Appendix D
b.	The utility shall compare the annual forecast of coincident peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the four years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecast in its most recently filed resource plan to the annual forecast in the current resource plan. In its initial IRP filing, the utility shall provide information demonstrating how well its forecasts during the preceding four years predicted demand.	Section 4; Appendix D
c.	The utility shall explain and document the assumptions, methodologies, and any other inputs upon which it relied to develop its load forecast.	Section 4; Appendices D, E, & F
E.	Load and resources table. The utility shall provide a load and resources table of its existing loads and resources at the time of its IRP filing. The load and resources table, to the extent practical, shall contain the appropriate components from the load forecast. Resources shall include:	Section 5 (Overall discussion in text; L&R table provided in Tables 5-1, 5-2, 5-3, & 5-4)
1.	utility-owned generation;	Section 5
2.	energy storage resources;	N/A
3.	existing and future contracted-for purchased power including qualifying facility purchases;	Section 5
4.	purchases through net metering programs, as appropriate;	Section 5
5.	demand-side resources, as appropriate; and	Section 5
6.	other resources relied upon by the utility, such as pooling, wheeling, or coordination agreements effective at the time the plan is filed.	Section 5
F.	Identification of resource options.	
1.	In identifying additional resource options, the utility shall consider all feasible supply-side, energy storage, and demand-side resources. The utility shall describe in its plan those resources it evaluated for selection to its portfolio and the assumptions and methodologies used in evaluating its resource options, including, as applicable: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility and efficiency of the resource.	Section 6; Appendix G
2.	For supply-side resource options, the utility shall identify the assumptions actually used for capital costs, fixed and variable operating and maintenance costs, fuel costs forecast by year, and purchased power demand and energy charges forecast by year, fuel type, heat rates, annual capacity factors, availability factors and, to the extent feasible, emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury.	Section 6; Appendix G
3.	The utility shall describe its existing rates and tariffs that incorporate load management or load shifting concepts. The utility shall also describe how changes in rate design might assist in meeting, delaying or avoiding the need for new capacity.	Section 6
G.	Determination of the most cost-effective resource portfolio and alternative portfolios.	

Southwestern Public Service Company
Applicable Electric Utility IRP Rule Requirements and Where Addressed in SPS's Filing

NMAC	Requirement	Where Addressed
1.	To identify the most cost-effective resource portfolio, utilities shall evaluate all feasible supply, energy storage, and demand-side resource options on a consistent and comparable basis, and take into consideration risk and uncertainty (including but not limited to financial, competitive, reliability, operational, fuel supply, price volatility and anticipated environmental regulation). The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis. The utility shall also consider and describe ways to mitigate ratepayer risk.	Section 7; Appendix J
2.	Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios:	
a.	load management and energy efficiency requirements;	Section 7
b.	renewable energy portfolio requirements;	Section 7
c.	existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions;	Section 7
d.	fuel diversity;	Section 7
e.	susceptibility to fuel interdependencies;	Section 7
f.	transmission constraints; and	Section 7
g.	system reliability and planning reserve margin requirements.	Section 7
3.	Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop a reasonable number of alternative portfolios by altering risk assumptions and other parameters developed by the utility and the public advisory process.	Section 7; Appendix J; Appendix H; Appendix I
H.	Public advisory process. Public input is critical to the development and implementation of integrated resource planning in New Mexico. A utility shall incorporate a public advisory process in the development of its IRP. At least one year prior to the filing date of its IRP, a utility shall initiate a public advisory process to develop its IRP. The purpose of this process shall be to receive public input, solicit public commentary concerning resource planning and related resource acquisition issues. This process shall be administered as follows.	Section 8; Appendix L
1.	The utility shall initiate the process by providing notice at least 30 days prior to the first scheduled meeting to the commission, interveners in its most recent general rate case, and participants in its most recent renewable energy, energy efficiency and IRP proceedings; the utility shall at the same time, also publish this notice in a newspaper of general circulation in every county which it serves and in the utility's billing inserts; this notice shall consist of:	Section 8; Appendix L; Appendix M
a.	a brief description of the IRP process;	Appendix L
b.	time, date and location of the first meeting;	Appendix L
c.	a statement that interested individuals should notify the utility of their interest in participating in the process; and	Appendix L
d.	utility contact information.	Appendix L
2.	Upon receipt of the initial notice, the commission may designate a facilitator to assist the participants with dispute resolution.	N/A (No facilitator designated)
3.	The utility or its designee shall chair the public participation process, schedule meetings, and develop agendas for these meetings. With adequate notice to the utility, participants shall be allowed to place items on the agenda of public participation process meetings.	Section 8; Appendix L
4.	Meetings held as part of the public participation process shall be noticed and scheduled on a regular basis and shall be open to members of the public who shall be heard and their input considered as part of the public participation process. Upon request, the utility shall provide an executive summary containing a non-technical description of its most recent IRP.	Section 8; Appendix M
5.	The purposes of the public participation process are for the utility to provide information to, and receive and consider input from, the public regarding the development of its IRP. Topics to be discussed as part of the public participation process include, but are not limited to, the utility's load forecast; evaluation of existing supply- and demand-side resources; the assessment of need for additional resources; identification of resource options; modeling and risk assumptions and the cost and general attributes of potential additional resources; and development of the most cost-effective portfolio of resources for the utility's IRP.	Section 8; Appendix M
6.	In its initial IRP advisory process, the utility and participants shall explore a procedure to coordinate the IRP process with renewable energy procurement plans and energy efficiency and load management program proposals. Any proposed procedure shall be designed to conserve commission, participant and utility resources and shall indicate what, if any, variances may be needed to effectuate the proposed procedure.	N/A
I.	Action plan.	

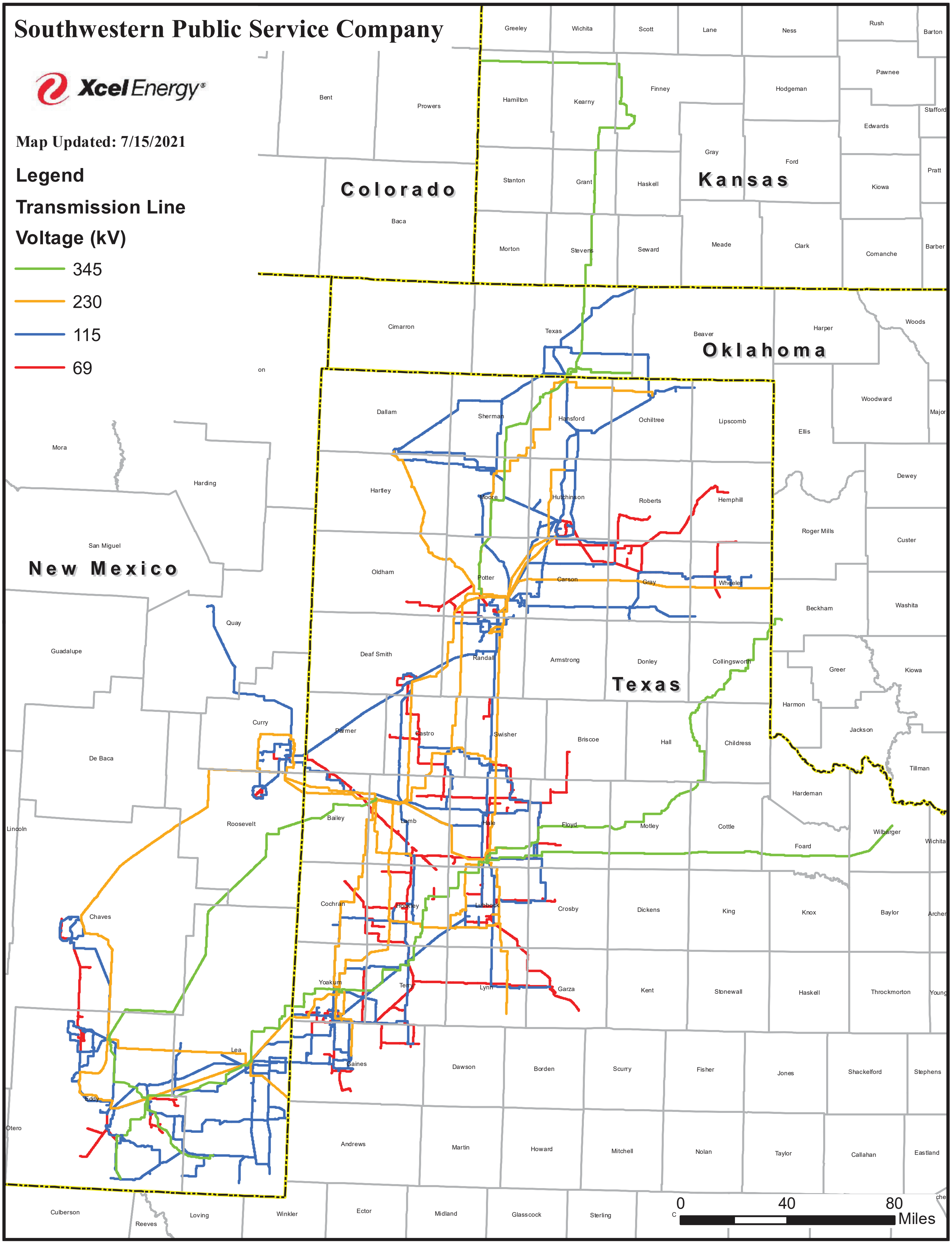
Southwestern Public Service Company
Applicable Electric Utility IRP Rule Requirements and Where Addressed in SPS's Filing

NMAC	Requirement	Where Addressed
1.	The utility's action plan shall detail the specific actions the utility will take to implement the integrated resource plan spanning a four-year period following the filing of the utility's IRP. The action plan will include a status report of the specific actions contained in the previous action plan.	Section 9
2.	An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations.	Section 9

Southwestern Public Service Company

Xcel Energy®

Map Updated: 7/15/2021



File Path: S:\General-Offices-GO-Trans\SLR-Mapping\GIS Projects\SPS System_SPS_System_Map.mxd

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S 2021 INTEGRATED RESOURCE PLAN FOR NEW MEXICO,)

SOUTHWESTERN PUBLIC SERVICE COMPANY,)

APPLICANT.)

) **CASE NO. 21-00169-UT**

CERTIFICATE OF SERVICE

I certify that true and correct copies of Southwestern Public Service Company's 2021 Integrated Resource Plan were electronically sent to each of the following on this 16th day of July 2021:

Dana S. Hardy	dhardy@hinklelawfirm.com;
Sarah Merrick	sarahmerrick@eversheds-sutherland.com;
Will DuBois	Will.w.dubois@xcelenergy.com;
William Grant	William.a.grant@xcelenergy.com;
Mario A. Contreras	Mario.a.contreras@xcelenergy.com;
Zoe E. Lees	Zoe.E.Lees@xcelenergy.com;
Mark A. Walker	Mark.A.Walker@xcelenergy.com;
Phillip Oldham	phillip.oldham@tklaw.com;
Katherine Coleman	katie.coleman@tklaw.com;
Michael McMillin	Michael.mcmillin@tklaw.com;
TKLaw office	tk.eservice@tklaw.com;
Melissa Trevino	Melissa_Trevino@oxy.com;
Jeffrey Pollock	jcp@pollockinc.com;
Joan Drake	jdrake@modrall.com;
Perry Robinson	Perry.Robinson@urenco.com;
Michael P. Gorman	mgorman@consultbai.com;
Amanda Alderson	aalderson@consultbai.com;
William Templeman	wtempleman@cmtisantafe.com;
Michael J. Moffett	mmoffett@cmtisantafe.com;
Cholla Khoury	ckhoury@nmag.gov;
Gideon Elliot	gelliot@nmag.gov;
Jennifer Van Wiel	jvanwiel@nmag.gov;
Andrea Crane	ctcolumbia@aol.com;
Doug Gegax	dgegax@nmsu.edu;
Jason Marks	lawoffice@jasonmarks.com;
Lauren Hogrewe	lauren.hogrewe@sierraclub.org;
Joshua Smith	Joshua.smith@sierraclub.org;
Dru Spiller	Dru.spiller@sierraclub.org;
Matthew Miller	Matthew.miller@sierraclub.org;
Stephanie Dzur	Stephanie@Dzur-Law.com;
Don Hancock	Sricdon@earthlink.net;
April Elliott	ccae@elliottanalytics.com;
Julia Broggi	jbroggi@hollandhart.com;
A.J. Gross	ajgross@hollandhart.com;
Luke Tougas	l.tougas@cleanenergyregresearch.com;
Mike Gallager	mgallagher@leacounty.net;
Randy Bartell	rbartell@montand.com;
Sharon Shaheen	sshaheen@montand.com;
Steve W. Chris	Stephen.Chriss@walmart.com;
David Austin Rueschhoff	darueschhoff@hollandhart.com;
Thorvald A. Nelson	tnelson@hollandhart.com;
Nikolas Stoffel	nsstoffel@hollandhart.com;
Adele Lee	aclee@hollandhart.com;
Gina Gargano-Amari	glgarganoamari@hollandhart.com;
B. Tyler	bltyler@hollandhart.com;
Steven S. Michel	smichel@westernresources.org;
Cydney Beadles	cydney.beadles@westernresources.org;
April Elliott	april.elliott@westernresources.org;
Pat O'Connell	pat.oconnell@westernresources.org;
Maj Holly L. Buchanan	Holly.buchanan.1@us.af.mil;
Mr. Thomas Jernigan	Thomas.Jernigan.3@us.af.mil;
Capt Robert L. Friedman	Robert.Friedman.5@us.af.mil;
Mrs. Ebony M. Payton	Ebony.Payton.ctr@us.af.mil;
TSgt Arnold Braxton	Arnold.Braxton@us.af.mil;
Steve Seelye	sseelye@theprimegroupllc.com;
Bradford Borman	Bradford.Borman@state.nm.us;
John Bogatko	John.Bogatko@state.nm.us;
Milo Chavez	Milo.Chavez@state.nm.us;
Marc Tupler	Marc.Tupler@state.nm.us;
John Reynolds	john.reynolds@state.nm.us;
Judith Amer	Judith.Amer@state.nm.us;
Jack Sidler	Jack.Sidler@state.nm.us;
Elisha Leyba-Tercero	Elisha.Leyba-Tercero@state.nm.us;
Gabriella Dasheno	Gabriella.Dasheno@state.nm.us;
Georgette Ramie	Georgette.Ramie@state.nm.us;
David Ault	David.Ault@state.nm.us;
Peggy Martinez-Rael	Peggy.Martinez-Rael@state.nm.us;
Elizabeth Ramirez	Elizabeth.Ramirez@state.mn.us;
Gilbert Fuentes	GilbertT.Fuentes@state.nm.us;
Andrew Unsicker	andrew.unsicker@us.af.mil;
Thomas Domme	tdomme@tecoenergy.com;
Rebecca Carter	racarter@tecoenergy.com;

Jane L. Yee	jyee@cabq.gov;
Linda L. Hudgins	linda.l.hudgins@xcelenergy.com;
Nann M. Winter	nwinter@stelznerlaw.com;
Adam Bickford	abickford@swenergy.org;
Sally Wilhelms	swilhelms@consultbai.com;
Rick Gilliam	rick@votesolar.org;
Kellie Barahona	kellie.barahona@tklaw.com;
Matthew Marchant	matthew.marchant@hollyfrontier.com;
Antonio Sanchez Jr.	sancheza@rcec.coop;
Chuck Pinson	cpinson@cvecoop.org;
Daniel A. Najjar	dnajjar@virtuelaw.com;
Carla R. Najjar	csnajjar@virtuelaw.com;
Nicole V. Strauser	nvstrauser@tecoenergy.com;
John Caldwell	jcaldwell@leacounty.net;
Ramona Blaber	ramona.blaber@sierraclub.org
Brian J. Haverly	bjh@keleher-law.com;
Sara Gersen	sgersen@earthjustice.org;
Randy Childress	randy@childresslaw.com;
Randall Woolridge	jrwoolridge@gmail;
Peter Gould	pgouldlaw@aol.com;
David Van Winkle	david@vw77.com;
Katelyn Hart	Katelyn.hart@gknet.com;
Anthony J. Trujillo	ajt@gknet.com;
Judith Amer	Judith.Amer@state.nm.us;

Respectfully submitted,
/s/ Casey Settles
Casey Settles
Southwestern Public Service Company
790 S. Buchanan, 7th Floor
Amarillo, TX 79101
(806)378-2462
Casey.Settles@xcelenergy.com