Southwestern Public Service Company

Load Research Program

There are several steps that are required for Load Research sample design. These steps outlined and described below are consistent with the Load Research methods developed by the Association of Edison Illuminating Companies ("AEIC").

1. **Accuracy**

   The accuracy of the load profile is a function of sample size and population variance. A design accuracy of ±10% at the 90% confidence level at the system and class peak time was specified in 1978 by Public Utility Regulatory Policies Act for all major rate classes. This is the recommended minimum requirement specified for any load profile and applies to the data used to develop the load profile (sample level or strata level).

   The specific parameters of the sample design are outlined in the Code of Federal Regulations ("CFR"), which states:

   > **Accuracy Level.** If sample metering is required, the sampling method and procedures for collecting, processing, and analyzing the sample loads, taken together, shall be designed so as to provide reasonably accurate data consistent with available technology and equipment. An accuracy of plus or minus 10 percent at the 90 percent confidence level shall be used as a target for the measurement of group loads at the time of system and customer group peaks.

2. **Design (Auxiliary) Variable**

   The design variable must be known for each unit of the entire population. Possible choices for the auxiliary variable in load profile applications are:
   - **Annual energy usage (used by Southwestern Public Service Company ("SPS"));**
   - Monthly energy usage;
   - Winter peak month energy usage;
   - Summer peak month energy usage;
   - Annual peak demand;
   - Monthly peak demand;
   - Summer peak demand;
   - Winter peak demand;
   - Type of appliances (electric heating or electric cooling);
   - Type of residence or business; and
   - Load factor.

3. **Sampling Methodology**

Several types of sampling procedures are commonly used to select individual sampling locations representative of a target population. The method chosen depends on the load characteristics to be estimated, the information available about the population, the uniformity of the population, and other sampling and budget constraints.

- Stratified random sampling **(used by SPS)**

  Divides the population into mutually exclusive, non-overlapping groups called strata. This type of sampling can involve stratifying in one or more dimensions.
- Census (100%) sampling **(used by SPS)**

  A stratum that contains a few customers that account for a large amount of load is a viable candidate for census sampling.

4. **Determining the Number of Strata and the Strata Boundaries**

The number of strata can often be determined for stratified random designs by calculating the coefficient of variation of the sampling distribution for test designs with different numbers of strata. The strata boundaries can be calculated by using the Dalenius-Hodges procedure or MBSS "strong stratification" as well as the analyst's judgment.

5. **Determining Sample Size**

The sampling method, estimation technique and required accuracy all influence sample size requirements. Sample size equations require estimates of the mean and variance of the variable of interest or an auxiliary variable. The preferred method of obtaining estimates for sample design is to derive them from prior load research data. When prior load research data are not available, a common procedure is to use an auxiliary variable (such as consumption) to estimate the mean and variance of the variable of interest.

Minimum requirements for sample size should be determined by the sampling method, estimation technique, and the chosen accuracy level plus a percentage margin to compensate for missing data. Sample sizes should be determined in such a way as to ensure accuracy for each month, not just the peak periods.

6. **Allocation**

There are two types of allocation techniques commonly used in load research sample design. Proportional allocation assigns sampling points to each stratum based upon the number of population units represented in the stratum. Neyman Allocation assigns sampling points to each stratum based upon the percentage of the total population standard deviation represented by the stratum.

7. **Accounting for Data Loss**

Since data will not be available for every customer during every time period in the study due to events such as equipment malfunction, human errors, customers moving, and customers requesting removal of recording equipment, techniques should be considered to account for data loss in the sample. There are two methods of accomplishing this. One technique is to apply a data loss factor which increases the overall sample size by a fixed percentage. Another technique is to set a minimum number of sample points per stratum and increase the sample size accordingly after allocation. The minimum number is a function of the data loss factor and research judgment. (No minimum requirement given). Sample participant attrition is also accounted for by SPS.

8. Selection of Alternate Sample Points

Once all efforts to install a particular metering site have failed, selecting sample replacements becomes necessary. Replacements are chosen in one of three ways: (1) replacements randomly chosen at the time of sample selection, (2) replacements systematically chosen at the time of sample selection, or (3) customers with similar information (usage, demographic, geographical location) chosen as backups. Any replacement method chosen should minimize sample bias.

9. Validation

After a prospective sample is chosen, it should be compared to the population to determine how well it represents the population, thus ensuring that the sample selection procedure has been performed correctly and that the appropriate sampling frame has been used. There are several methods of performing this validation. The simplest is to compare the sample mean usage to the population mean usage (annual or monthly). A more complex procedure involves setting specific tolerance ranges which the sample must meet for specific variables. Samples are then selected until a suitable sample is found. A third method is to select numerous samples and choose the sample that best matches the population for specific variables.

10. Customer Solicitation

Many utilities seek the customer's agreement to participate even though, legally, such an agreement may not be necessary. Therefore, there are three alternatives to customer solicitation: customer approval required, customers notified but approval not required, or customers not notified. Since customer rejection could introduce sampling bias, care should be taken when choosing the method of customer solicitation. Bias is the difference between the mean value of the estimate and the true value being estimated. Sampling bias occurs when some members of the population about which inferences are to be made are accidentally or purposely excluded from the population frame.

Southwestern Public Service Company

Description of Company

Southwestern Public Service Company, a New Mexico corporation ("SPS"), is an electric utility company and wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a utility holding company that was incorporated under the laws of Minnesota in 1909. Xcel Energy, through its subsidiaries, is a major U.S. electric and natural gas company, with annual revenues of more than $13.4 billion. Based in Minneapolis, Minnesota, Xcel Energy operates in eight western and mid-western states. Xcel Energy provides a comprehensive portfolio of energy-related products and services to 3.7 million electricity customers and 2.1 million natural gas customers. Through a subsidiary, Xcel Energy Transmission Holding Company, LLC, Xcel Energy also owns three transmission- only operating companies: Xcel Energy Southwest Transmission Company, LLC; Xcel Energy Transmission Development Company, LLC; and Xcel Energy West Transmission Company, LLC, all of which are either currently regulated by the Federal Energy Regulatory Commission ("FERC") or expected to be regulated by FERC. In terms of customers, Xcel Energy is the fourth-largest combination electric and natural gas company in the nation.

SPS serves approximately 127,000 New Mexico electric customers (404,000 total company) in a 52,000 square mile area of the Panhandle and the South Plains of Texas, as well as eastern and southern New Mexico. SPS has no non-regulated activities. Its service area has a customer density of 7.7 customers per square mile. The total electric customer count is comprised of: 78.69% New Mexico Residential customers (78.86% total company Residential customers), 19.90% New Mexico Commercial and Industrial customers (19.57% total company Commercial and Industrial customers), 6.7% New Mexico Lighting customers (4.8% total company Lighting customers), and 1.39% New Mexico Municipal and School customers (1.54% total company Municipal and School customers). SPS also serves five production transmission wholesale customers.

SPS's service territory is primarily agricultural, with large areas of oil and gas production. The oil and natural gas segments have been growing rapidly. SPS serves most of the cities and towns within the service territory, while many areas outside those towns are served by rural electric cooperatives.

The agricultural areas are mostly irrigated by pumping from natural underground water supplies. Crops include cotton, corn, grain sorghums, soybeans, and peanuts. Also, there is a large investment in cattle feeding operations in the service territory. The dairy and cheese industries are expanding within the service territory.

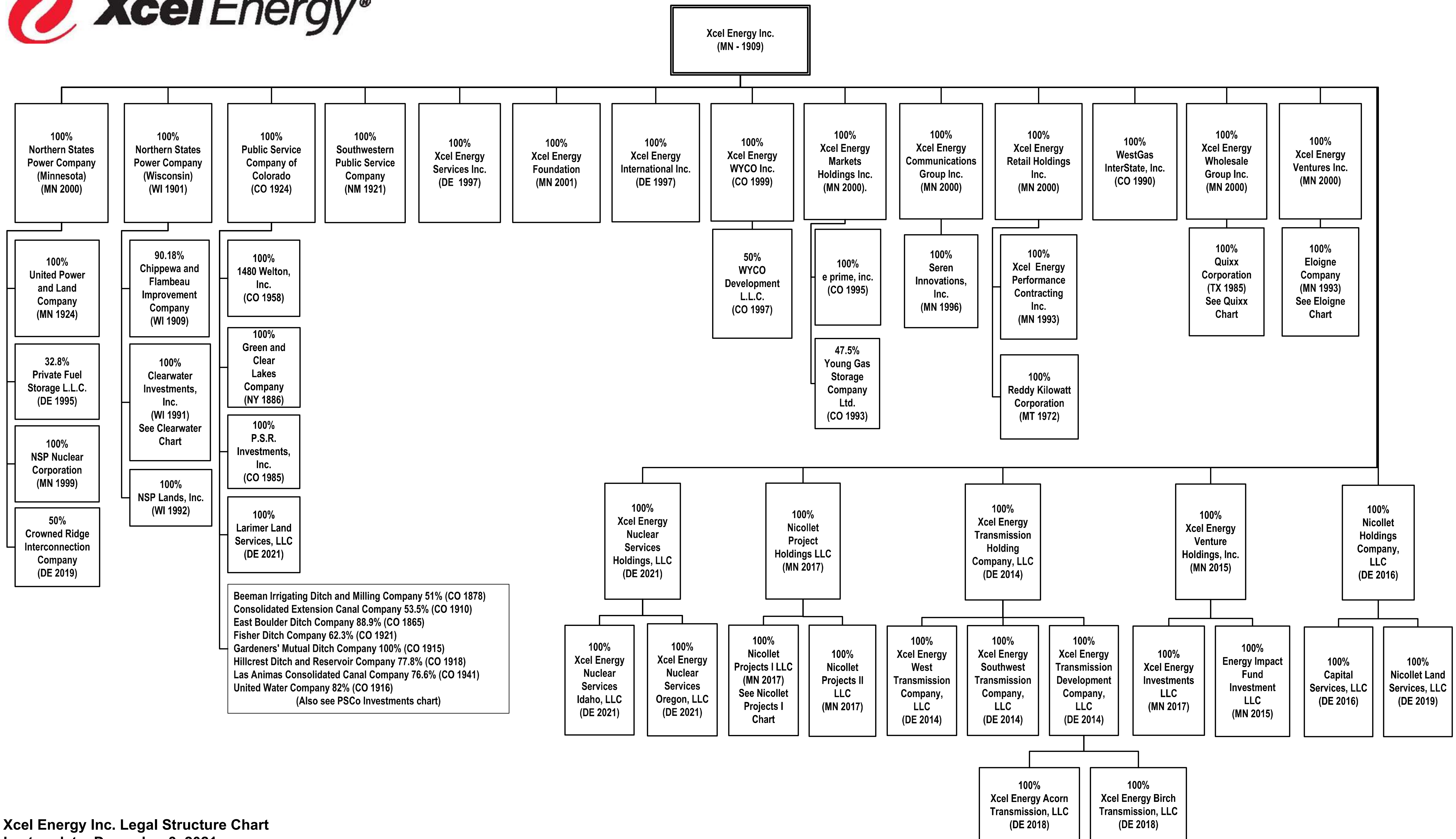
SPS is regulated by the 82 municipalities it serves in Texas, the Public Utility Commission of Texas, the New Mexico Public Regulation Commission and the FERC.

SPS is uniquely located relative to the electrical grid of North America. SPS is a member of the Southwest Power Pool, Inc. ("SPP"), which is a FERC-approved regional transmission organization. SPS is located in the southwest corner of SPP and the Eastern Interconnection. It is bordered to the west by the Western Electricity Coordinating Council ("WECC") and to the south and southeast by the Electric Reliability Council of Texas ("ERCOT").

SPS is interconnected with the Eastern Interconnection through eight synchronous transmission ties with the SPP. Three of these interconnections tie to utility operating company subsidiaries of American Electric Power Company with the SPS interconnections located near Elk City, Oklahoma (230 kV); Shamrock, Texas (115 kV); and Oklaunion, Texas (345 kV). Three of these interconnections tie to Oklahoma Gas and Electric Company with the interconnections located near Erick, Oklahoma (345kV) and two interconnections located near Balko, Oklahoma (345kV). Finally, two of these interconnections tie to Sunflower Electric Power Corporation, with the SPS interconnections located near Holcomb, Kansas (345kV) Guymon, Oklahoma (115kV).

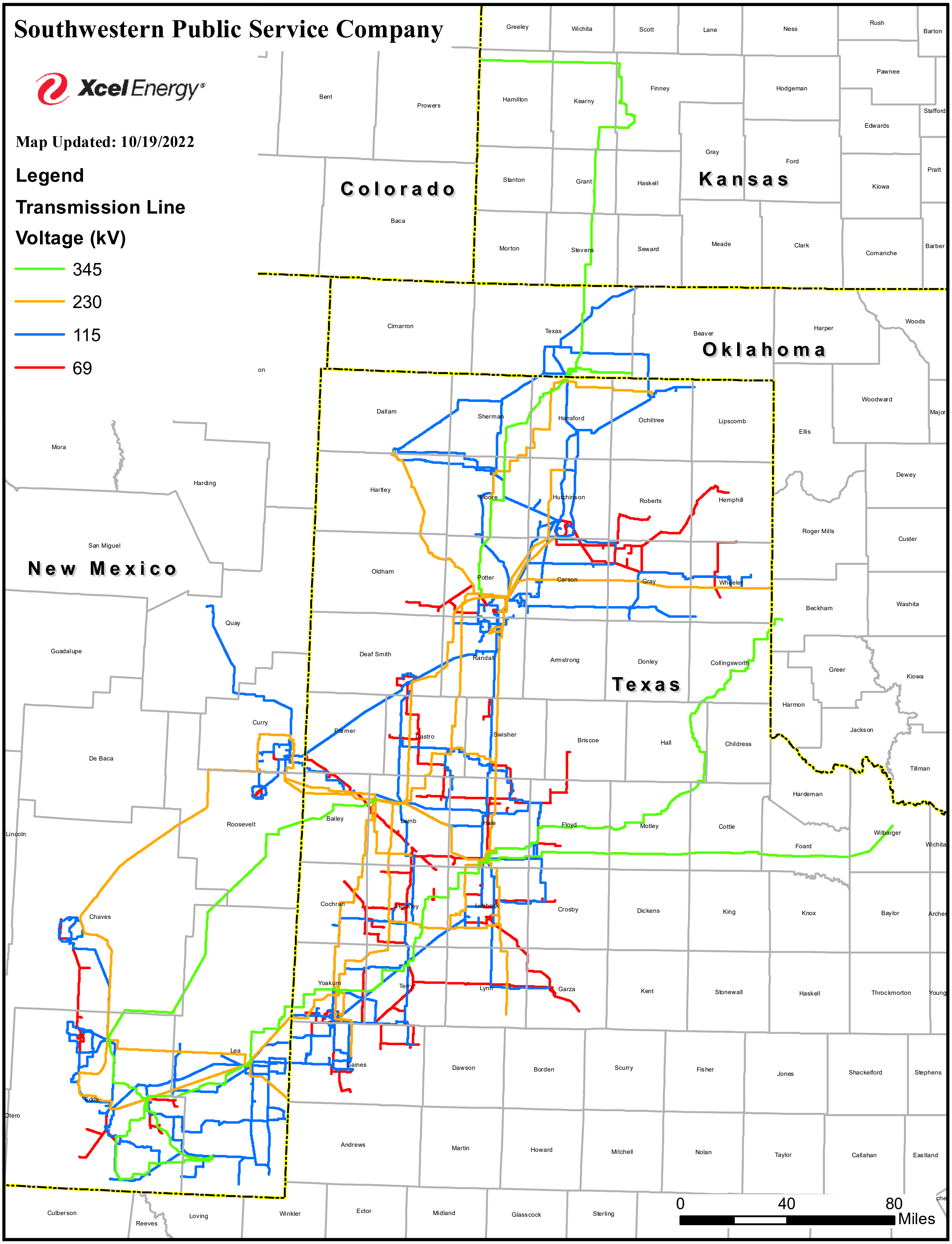
SPS is interconnected to the Western Interconnection through three high-voltage direct-current ("HVDC") converters owned by three utilities in the WECC. SPS is interconnected to the west jointly with El Paso Electric Company and Public Service Company of New Mexico ("PNM") at the Eddy County HVDC tie located near Artesia, New Mexico, and then with PNM solely in Roosevelt County, New Mexico at the Blackwater Draw HVDC tie located near Clovis, New Mexico. The third HVDC tie is with Public Service Company of Colorado, an Xcel Energy operating company, at the Lamar HVDC tie in Prowers County, Colorado.

SPS is not interconnected with ERCOT.



Xcel Energy Inc. Legal Structure Chart
Last update: December 3, 2021
Effective as of: December 8, 2021

Sponsors: Davis, Trammell
Case No. 22-00286-UT



File Path: S:\General-Offices-GO-Trans\SLR-Mapping\GIS Projects\SPS System_SPS_System_Map.mxd

Southwestern Public Service Company
Description of Company: Public Utility (electric)
List and Description of Affiliates
As of June 30, 2022

Line No.	Name	Description	Incorporated	Owner	Ownership %
1	**Xcel Energy Inc. (Xcel Energy)**	Holding Company.	MN - 1909		
2	**Northern States Power Co., a Minnesota Corporation**	Public utility (gas & electric).	MN - 2000	Xcel Energy Inc.	100.00%
3	NSP Nuclear Corporation	Holds NSP-MN's interest in Nuclear Management Co. LLC.	MN - 1999	NSP - MN	100.00%
4	Private Fuel Storage LLC	Development of private temporary spent nuclear fuel storage facility.	DE - 1995	NSP - MN	32.80%
5	United Power and Land Co. (UP&L)	Holds non-utility real estate.	MN - 1924	NSP - MN	100.00%
6	Crowned Ridge Interconnection Company	Energy Generation Investment	DE - 2019	NSP - MN	50%
7	**Northern States Power Co., a Wisconsin Corporation (NSP-WI)**	Public utility (gas & electric).	WI - 1901	Xcel Energy Inc.	100.00%
8	Chippewa and Flambeau Improvement Co.	Operates hydro reservoirs in Wisconsin.	WI - 1909	NSP - WI	88.02
9	Clearwater Investments, Inc. (Clearwater Inv.)	Owns interests in affordable housing projects.	WI - 1991	NSP - WI	100.00%
10	Shoe Factory Holdings, LLC	Owns interests in affordable housing projects.	WI - 1994	Clearwater Inv	98.99%
11	NSP Lands Inc.	Holds non-utility real estate in Wisconsin.	WI - 1992	NSP - WI	100.00%
12	**Xcel Energy Foundation**	Charitable activities.	MN - 2001	Xcel Energy Inc.	100.00%
13	**Southwestern Public Service Company**	Public Utility.	NM - 1921	Xcel Energy Inc.	100.00%
14	**Public Service Co. of Colorado (PSCo)**	Public utility (gas, electric & thermal).	CO - 1924	Xcel Energy Inc.	100.00%
15	PSR Investments Inc.	Owns certain life insurance policies acquired prior to 1986.	CO - 1985	PSCo	100.00%
16	1480 Welton Inc.	Holds real estate.	CO - 1958	PSCo	100.00%
17	Green and Clear Lakes Co.	Water storage for Cabin Creek hydro facility.	NY - 1886	PSCo	100.00%
18	Larimer Land Services LLC	Holding company	DE - 2021	PSCo	100.00%
19	Beeman Irrigating Ditch and Milling Co.	Cooling water for generating facilities.	CO - 1887	PSCo	51.00%
20	Consolidated Extension Canal Co.	Cooling water for generating facilities.	CO - 1910	PSCo	53.54
21	East Boulder Ditch Co.	Cooling water for generating facilities.	CO - 1865	PSCo	88.90%
22	Fisher Ditch Co.	Cooling water for generating facilities.	CO - 1921	PSCo	62.32
23	Gardeners' Mutual Ditch Co.	Cooling water for generating facilities.	CO - 1915	PSCo	100.00%
24	Hillcrest Ditch and Reservoir Co.	Cooling water for generating facilities.	CO - 1918	PSCo	77.80%
25	Las Animas Consolidated Canal Co.	Cooling water for generating facilities.	CO - 1941	PSCo	85.62
26	United Water Co.	Cooling water for generating facilities.	CO - 1916	PSCo	82.14
27	**WestGas InterState Inc.**	Natural gas transmission company.	CO - 1990	Xcel Energy Inc.	100.00%
28	**Xcel Energy International Inc. (Xcel Energy Intl.)****	Intermediate holding company for international subsidiaries.	DE - 1997	Xcel Energy Inc.	100.00%
29	**Xcel Energy WYCO Inc. (Xcel Energy WYCO)**	Finances and holds 50% interest in WYCO Development LLC.	CO - 1999	Xcel Energy Inc.	100.00%
30	WYCO Development LLC	Acquire, own and lease natural gas transportation facilities.	CO - 1997	Xcel Energy WYCO	50.00%
31	**Xcel Energy Markets Holdings Inc. (Xcel Energy Mkts)**	Intermediate holding company for subsidiaries. providing energy marketing services	MN - 2000	Xcel Energy Inc.	100.00%

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32	e prime Inc. (e prime)**	Unregulated commodity marketing affiliate.	CO - 1995	Xcel Energy Mkts	100.00%
33	Young Gas Storage Co. Ltd.	Owns and operates an underground gas storage.	CO - 1993	Xcel Energy Mkts	47.50%
34	**Xcel Energy Communications Group Inc. (Xcel Energy Comm.)**	Intermediate holding company for subsidiaries providing broadband telecommunications.	MN - 2000	Xcel Energy Inc.	100.00%
35	Seren Innovations Inc.**	Provides cable, telephone and high speed internet access.	MN - 1996 11-3-05 Calif. assets sold	Xcel Energy Comm	100.00%
36	**Xcel Energy Nuclear Services Holdings, LLC**	Holding Company	DE - 2021	Xcel Energy Inc.	100.00%
37	Xcel Energy Nuclear Services Idaho, LLC	Service Company	DE - 2021	Xcel Energy Nuclear Services Holdings, LLC	100.00%
38	Xcel Energy Nuclear Services Oregon, LLC	Service Company	DE - 2021	Xcel Energy Nuclear Services Holdings, LLC	100.00%
39	**Xcel Energy Retail Holdings Inc. (Xcel Energy Retail)**	Intermediate holding company for subsidiaries providing services to retail customers.	MN - 2000	Xcel Energy Inc.	100.00%
40	Reddy Kilowatt Corporation	Energy sales and marketing services.	MT - 1972	Xcel Energy Retail	100.00%
41	Xcel Energy Performance Contracting Inc.	Holds contracts related to energy conservation.	MN - 1993	Xcel Energy Retail	100.00%
42	**Xcel Energy Services Inc. (Xcel Energy Svcs.)**	Service company for Xcel Energy system.	DE - 1997	Xcel Energy Inc.	100.00%
43	**Xcel Energy Wholesale Group Inc. (Xcel Energy Wholesale)****	Intermediate holding company. for subsidiaries providing wholesale energy	MN - 2000	Xcel Energy Inc.	100.00%
44	Quixx Corporation (Quixx Corp.)**	Energy related projects.	TX - 1985	Xcel Energy Wholesale	100.00%
45	Quixx Carolina Inc. (Quixx Carolina)**	Energy related projects.	TX - 1995	Quixx Corp.	100.00%
46	Quixxlin Corp. (Quixxlin)**	Energy related projects.	DE - 1997	Quixx Corp.	100.00%
47	**Xcel Energy Ventures Inc. (Xcel Energy Ventures)**	Intermediate holding company for subsidiaries to develop and manage new business ventures.	MN - 2000	Xcel Energy Inc.	100.00%
48	Eloigne Co. (Eloigne)	Owns interests in affordable housing projects which qualify for low income housing tax credits.	MN - 1993	Xcel Energy Ventures	100.00%
49	Bemidji Townhouse LP	Owns interests in affordable housing projects.	MN - 5/3/93	Eloigne	99.00%
50	Chaska Brickstone LP	Owns interests in affordable housing projects.	MN - 10/7/97	Eloigne	99.99%
51	Cottage Court LP	Owns interests in affordable housing projects.	MN - 6/23/94	Eloigne	99.00%
52	Crown Ridge Apartments LP	Owns interests in affordable housing projects.	MN - 2/16/96	Eloigne	99.99%
53	Edenvale Family Housing LP	Owns interests in affordable housing projects.	MN - 8/29/97	Eloigne	99.99%
54	Fairview Ridge LP	Owns interests in affordable housing projects.	MN - 12/20/93	Eloigne	99.00%
55	Farmington Family Housing LP	Owns interests in affordable housing projects.	MN - 2/16/99	Eloigne	99.99%
56	Farmington Townhome LP	Owns interests in affordable housing projects.	MN - 2/15/98	Eloigne	99.99%
57	Hearthstone Village LP	Owns interests in affordable housing projects.	ND - 9/14/97	Eloigne	99.00%
58	J&D 14-93 LP	Owns interests in affordable housing projects.	MN - 1/3/94	Eloigne	99.00%
59	Lauring Green LP	Owns interests in affordable housing projects.	MN - 8/14/89	Eloigne	99.00%
60	Links Lane LP	Owns interests in affordable housing projects.	MN - 8/11/93	Eloigne	99.00%
61	Lyndale Avenue Townhomes LP	Owns interests in affordable housing projects.	MN - 5/6/99	Eloigne	99.99%

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62	Mahtomedi Woodland LP	Owns interests in affordable housing projects.	MN - 12/3/96	Eloigne	99.00%
63	Mankato Townhomes I LP	Owns interests in affordable housing projects.	MN - 6/20/97	Eloigne	59.99%
64	Marvin Garden LP	Owns interests in affordable housing projects.	MN - 4/1/94	Eloigne	99.00%
65	Moorhead Townhomes LP	Owns interests in affordable housing projects.	MN - 9/8/99	Eloigne	99.99%
66	Park Rapids Townhomes LP	Owns interests in affordable housing projects.	MN - 6/17/95	Eloigne	99.99%
67	Rochester Townhome LP	Owns interests in affordable housing projects.	MN - 2/5/98	Eloigne	99.00%
68	Rushford Housing LP	Owns interests in affordable housing projects.	MN - 3/27/96	Eloigne	99.99%
69	Safe Haven Homes LLC	Owns interests in affordable housing projects.	DE - 1997	Eloigne	100.00%
70	Shade Tree Apartments LP	Owns interests in affordable housing projects.	MN - 6/11/99	Eloigne	99.99%
71	Shakopee Boulder Ridge LP	Owns interests in affordable housing projects.	MN - 10/20/98	Eloigne	99.99%
72	Shenandoah Woods LP	Owns interests in affordable housing projects.	MN - 8/29/97	Eloigne	99.99%
73	St. Cloud Housing LP	Owns interests in affordable housing projects.	MN - 1/13/03	Eloigne	99.99%
74	Tower Terrace LP	Owns interests in affordable housing projects.	MN - 5/9/94	Eloigne	99.00%
75	**Nicollet Holdings Company, LLC**	Holding Company.	DE - 2016	Xcel Energy Inc.	100.00%
76	Capital Services, LLC	Internal Support Service.	DE - 2016	Nicollet Holdings Company, Inc.	100.00%
77	Nicollet Project Holdings LLC	Holding Company.	MN - 2017	Xcel Energy Inc.	100.00%
78	Nicollet Projects I LLC	Energy generation investment.	MN - 2017	Nicollet Project Holdings LLC	100.00%
79	Betcher CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
80	Foreman's Hill CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
81	Grimm CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
82	Heyer CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
83	Huneke CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
84	Johnson I CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
85	Johnson II CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
86	Krause CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
87	RJC I CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
88	RJC II CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
89	Scandia CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
90	School Sisters CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
91	Webster CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
92	Nicollet Projects II LLC	Energy generation investment.	MN - 2017	Nicollet Project Holdings LLC	100.00%
93	**Xcel Energy Transmission Holding Company, LLC (Xcel Energy Transmission Holding Company)**	Intermediate holding company for subsidiaries providing energy transmission services.	DE - 2014	Xcel Energy Inc.	100.00%
94	Xcel Energy Southwest Transmission Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
95	Xcel Energy Transmission Development Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
96	Xcel Energy Acorn Transmission, LLC	Provide transmission services.	DE - 2018	Xcel Energy Transmission Development Company, LLC	100.00%

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97	Xcel Energy Birch Transmission, LLC	Provide transmission services.	DE - 2018	Xcel Energy Transmission Development Company, LLC	100.00%
98	Xcel Energy West Transmission Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
99	**Xcel Energy Venture Holdings, Inc.**	Holdling Company.	MN - 2015	Xcel Energy Inc.	100.00%
100	Energy Impact Fund Investment LLC	Energy Investment.	MN - 2015	Xcel Energy Venture Holdings, Inc.	100.00%
101	Xcel Energy Investments LLC	Energy Investment.	MN - 2017	Xcel Energy Venture Holdings, Inc.	100.00%

Xcel Energy®

HORIZON BOUND

2021
ANNUAL REPORT

COMPANY DESCRIPTION

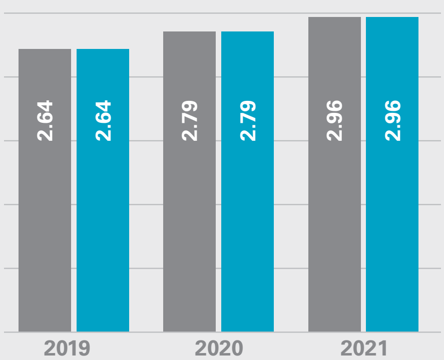
Xcel Energy is a major U.S. electric and natural gas company with annual revenues of $13.4 billion. Based in Minneapolis, Minnesota, the company operates in eight states and provides a comprehensive portfolio of energy-related products and services to 3.7 million electricity customers and 2.1 million natural gas customers.

FINANCIAL HIGHLIGHTS

	2020	2021
Total GAAP earnings per share	2.79	2.96
Ongoing earnings per share	2.79	2.96
Dividends annualized	1.72	1.83
Stock price (close)	66.67	67.70
Assets (millions)	53,957	57,851

EARNINGS PER SHARE

Dollars per share (diluted)



GAAP (generally accepted accounting principles) earnings per share

Ongoing earnings per share

INCREASED FOCUS ON DEI DRIVES POSITIVE RESULTS

Xcel Energy is committed to cultivating an equitable and inclusive work environment, with a skilled, engaged and diverse workforce that reflects the communities we serve. We continue to weave the importance of diversity, equity and inclusion (DEI) into the fabric of our company and to provide an environment where all employees feel they can be themselves and genuinely are included and empowered to do their best work.

To ensure this crucial topic receives appropriate attention and visibility, the company adopted a new index to measure progress on specific aspects of DEI for the corporate scorecard in 2021. The index measures three key elements of the company's DEI strategy: the use of diverse interview panels in the hiring process, performance of our overall inclusion index and active participation in the executive sponsorship program that supports career growth by pairing executives with employees who are diverse from themselves.

Xcel Energy exceeded its targets for each of the three factors in 2021 and will retain the DEI metric on its corporate scorecard in 2022.

As a result of our commitment to diversity, we have seen a 6% increase in women and a 5% increase in diverse representation within our senior leadership at the vice-presidential level and above.

"As a purpose-driven and values-led organization, we continue to build a culture of belonging where diverse viewpoints are appreciated," said Baird McKevitt, Director, Inclusion and Diversity.

ON THE COVER: Pictured is a solar facility in Eau Claire, Wisconsin, adjacent to our state headquarters. Xcel Energy is working towards several clean energy milestones on the horizon at the end of the decade.

DEAR FELLOW SHAREHOLDERS

Xcel Energy achieved strong financial and operational results again in 2021, despite the second year of a global pandemic and severe weather challenges. During these tough times, we delivered for our customers and communities when they needed us most, and we continued to advance our financial, operational, and sustainability goals.

Our theme for this report, "Horizon Bound," reflects our balanced, organic growth and our aggressive clean energy targets for the next decade and beyond. In the next eight years, we will add significant renewable generation to our system, expand our transmission infrastructure to enable those resources, deploy new clean fuels to power our customers and heat their homes, invest in grid resiliency and automation, and enable electrification of transportation at scale, all while keeping customer bills affordable. This report showcases how our team is working hard to deliver for you, our valued shareholders.

CEO transition

It was an honor to be elected by our Board of Directors to replace retiring Ben Fowke as our company's CEO in August. I worked closely with Ben for five years, first as Chief Financial Officer and more recently as President and Chief Operating Officer. We share the same vision for the company and executed our transition in August from a position of strength — our reputation is excellent, our balance sheet is healthy, our operations are strong, and our strategy is sound.

Bob Frenzel
Chairman, President and Chief Executive Officer

Solid financial performance

For the 17th consecutive year, we met or exceeded our earnings guidance, and we increased our dividend for the 18th consecutive year. We delivered earnings of $2.96 per share, within the upper half of our initial guidance range. We increased our dividend 6.4%, or 11 cents per share in 2021, which is in line with our 5% to 7% goal. Our stock continues to trade at a premium and has outperformed our peer group for the three-, five- and ten-year periods.

Our robust five-year, $26 billion capital investment plan will provide significant customer value and drive regulated rate base growth of 6.5%. And, we've identified additional investment opportunities in that timeframe for an incremental capital investment of $1.5 to $2.5 billion, which would increase our growth rate to 7.4%.

Clean energy leadership

In November, we announced a clean energy vision for our natural gas distribution business. Our vision reduces greenhouse gas emissions 25% from 2020 levels by 2030, including net-zero methane emissions from our distribution system, and delivers net-zero natural gas service to customers by 2050. (See story on page 14).

Our natural gas vision builds on our previously announced electric goals for reducing carbon emissions 80% by 2030 and producing 100% carbon-free electricity by 2050. We also plan to use our increasingly clean product to power 1.5 million electric vehicles in our states by the end of the decade, resulting in additional carbon reduction, future sales growth, and customer fuel savings. Together, these commitments represent a comprehensive clean energy vision, making Xcel Energy the first U.S. energy provider to set aggressive clean energy goals across all the ways our customers use energy: electricity, transportation, and heating. And we are well on our way to achieving that vision.

Delivering at critical times

We never take for granted the trust we have earned to power millions of homes and businesses all day, every day, particularly during extreme weather. In 2021, there were two significant events that impacted our service territory — Winter Storm Uri in Texas and the Marshall Wildfire in Colorado. These two natural disasters challenged our teams to deliver in the most arduous conditions. And as always, we rose to the challenge.

Historic cold temperatures during Winter Storm Uri froze natural gas wells throughout Texas and Oklahoma, creating natural gas supply constraints and price spikes across the country. At the same time, the Texas electric system saw generation equipment failures caused by the cold, which left millions without power or heat. Our plants and equipment in the Southwest are winterized for extreme temperatures and performed very well during the event, despite widespread failures of other generating assets.

Despite our employees operating our gas distribution system extremely capably during the 10-day record-setting cold period, we were not immune from the sudden, extraordinary increase in natural gas prices that went along with Winter Storm Uri. We incurred $925 million of additional fuel costs that we are working with regulators to recover while helping customers manage costs.

Following a particularly dry fourth quarter, on Dec. 30, Colorado faced an intense windstorm that packed 110 mph winds and fueled the devastating Marshall Wildfire. The Boulder County fires destroyed more than 1,200 homes and businesses in the area, and partially or totally destroyed the homes of 17 of our own employees.

Hundreds of employees, contractors and mutual aid crews were on the scene as soon as it was safe and worked around the clock to get service restored to the impacted communities.

These extreme weather events reinforce the need for continued investment in system resiliency, such as our approved wildfire mitigation program, to protect communities from the growing impacts of climate change.

Constructive regulatory outcomes

We reached constructive rate case settlements in six states last year. In Colorado, we also reached constructive settlements for Winter Storm Uri cost recovery, our electric resource plan and our Power Pathway transmission project, a nearly $2 billion investment necessary to enable future renewable generation assets.

The New Mexico commission approved our Transportation Electrification Plan, and we launched several commercial and residential programs to support electric vehicle adoption in Colorado as part of our approved, industry-leading Transportation Electrification Plan. (See story on pages 10-11). In February 2022, the New Mexico commission also approved our electric rate case settlement.

Also in February 2022, the company received approval for its Upper Midwest Generation Resource Plan, including a full closure of all coal plants in the region by 2030, over 85% carbon reduction, 5,750 megawatts of new wind and solar assets, and transmission infrastructure to enable those resources. The plan also includes a license extension of our Monticello nuclear plant through 2040. Our proposed resource plan in Colorado would add 5,100 megawatts of new renewable generation assets and is expected to reduce carbon emissions 87% by 2030. (See story on pages 8-9).

Renewable energy expansion

Our Steel for Fuel strategy — building and owning wind farms that deliver economic and environmental benefits for our customers — continues to drive organic growth, provide an attractive shareholder return, and save customers money. Since 2017, wind energy — through a combination of fuel savings and tax credits — saved customers an estimated $1.8 billion.

We now have over 11,000 megawatts of total wind capacity, including nearly 4,500 megawatts of owned wind. We also advanced plans for owning our first large-scale solar projects. We received approval for a 74-megawatt solar project in Wisconsin and proposed a 460-megawatt project near our Sherco coal plant in Minnesota.

Advanced Grid Initiative

Our $1.7 billion, multi-year Advanced Grid Initiative, to use advanced technology to bring customers cleaner, safer, more reliable energy, achieved a significant milestone in 2021 as the first batch of 310,000 smart meters were installed in Colorado. The two-way communication capabilities will help improve reliability, reduce the time it takes to restore power during an outage, and provide customers more options to manage their energy use and save money. (See story on pages 6-7).

Operational excellence

Operational excellence is at the core of our commitment and approach to operating our plants and facilities and our preparedness to respond to extreme weather and other events. We remain the top-performing nuclear fleet in the country. One of our units at Prairie Island operated for a record 703 consecutive days before its scheduled refueling in October. Additionally, we have held our operating and maintenance costs flat since 2013, helping to keep customer bills low without compromising safety or reliability. We remain committed to our industry-leading "Safety Always" program. (See story on pages 12-13).

Employee focus

As we have done since the start of the pandemic, our employees continue to follow extra safety protocols to protect themselves, their coworkers, and their loved ones from COVID-19. Approximately half of our employees worked remotely in 2021 but are returning to the office this spring with a hybrid work schedule as the pandemic continues to recede.

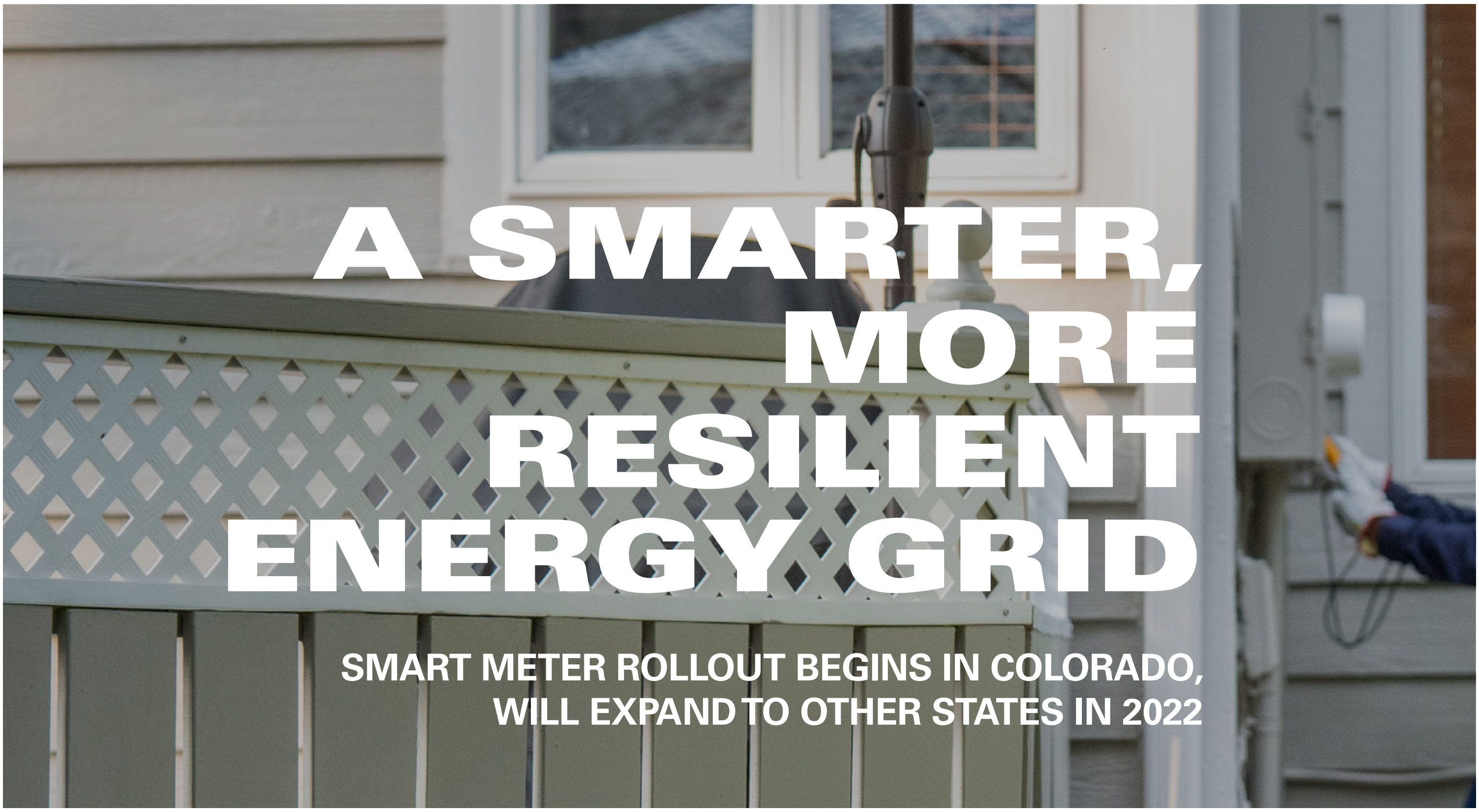
The company added diversity, equity, and inclusion (DEI) metrics to its corporate scorecard for the first time in 2021, and I am pleased to report that we exceeded our goals. Diversity and inclusion make us a stronger company and a more welcoming workplace, where we can attract and retain top talent. (See story on page 2).

It's an honor to lead this team — more than 11,000 employees strong — that is consistently recognized with its outstanding business practices and ethics, operational performance, veteran hiring, and workplace culture. We were honored to be named among the World's Most Ethical Companies® by Ethisphere for the third consecutive year, reflecting the company's commitment to sustainability and ethical business practices. We also were among the Human Rights Campaign's Best Places to Work for LGBTQ Equality, earning a perfect score on its Corporate Equality Index for the sixth consecutive year. We were named one of Fortune's Most Admired Companies for the ninth consecutive year and ranked second among energy providers.

With the best employees in the industry serving you, I'm excited about the future — not just what's in store for 2022, but for the transformative progress on the horizon. You can count on the Xcel Energy team to deliver for you. Thanks for the continued trust you place in us.

Sincerely,

Bob Frenzel
Chairman, President and
Chief Executive Officer



A SMARTER, MORE RESILIENT ENERGY GRID

SMART METER ROLLOUT BEGINS IN COLORADO, WILL EXPAND TO OTHER STATES IN 2022

BUILDING THE ENERGY GRID OF THE FUTURE IS WELL ON ITS WAY. AFTER FOUR YEARS OF PLANNING, FOUNDATIONAL WORK AND SOFTWARE DEVELOPMENT, XCEL ENERGY'S ADVANCED GRID INITIATIVE ACHIEVED A MAJOR MILESTONE IN 2021 WHEN THE FIRST WAVE OF SMART METERS WAS DEPLOYED AT 310,000 COLORADO CUSTOMER HOMES.

The $1.7 billion, multi-year grid transformation deploys industry-leading technology to help Xcel Energy better manage the grid and deliver an improved customer experience through improved outage response and the ability for customers to better manage their energy use.

The Advanced Grid Initiative enhances distribution operations through the deployment of new software, building a two-way communications network, adding new automated field devices and installing smart meters at customer premises. The smart meters deliver numerous customer and operational benefits, providing near-real-time communication between the customer and Xcel Energy, so customers know exactly how much energy they are using and what it will cost them. The meters also provide increased automation that reduces the need for manual meter reading or estimating usage, and improves efficiency.

"Smart meters are the foundational technology needed to enable a new suite of energy-related products and services for our customers," said Steve Foss, Regional Vice President for Distribution Operations. "Our industry-leading Advanced Grid Initiative will deliver outstanding value to our customers, and we are excited about the potential capabilities we see on the horizon."

In Colorado, the initiative includes time-of-use rates that incent customers who use electricity during off-peak hours. Small changes like running the dishwasher or operating laundry machines later at night or in the morning will generate savings on energy bills. Previously, energy rates in the state remained constant at all hours because older meter technology could not differentiate usage by time of day.

Customers will have new digital tools to make it easy to access their energy information and gain useful insights to better understand and manage their energy use and make smarter energy choices that lower their bills and save money.

To prepare for the smart meter rollout, a secure field network communications system was built and expanded, allowing the smart meters to send encrypted information to Xcel Energy through a series of secure communication devices. Simultaneously, new software tools and controls were deployed for the company's distribution control centers to increase reliability and resiliency, optimize voltage levels throughout the system and help the company better manage the energy grid throughout our eight-state footprint. An advanced application in the new system software for voltage management, along with the addition of 430 field devices, generated 127.5 gigawatt hours of energy savings for customers in Colorado last year.

While the rollout will continue in Colorado over the next three years, the first smart meters are expected to begin deployment in Minnesota in 2022 and the Dakotas in 2023, with Texas, New Mexico, Wisconsin and Michigan starting later. By the end of 2024, nearly 3.9 million smart meters will be installed across our eight states.

Operations Manager Jamin Argon from the Advanced Grid Initiative team explains the benefits of a smart meter to Xcel Energy customer Kelly Almer of Littleton, Colorado. Installed by Senior Meter Technician Sandra Perez, the smart meter was one of 310,000 connected to the grid in Colorado last year.

"Our customers and communities will benefit significantly from our industry-leading Advanced Grid Initiative," Foss said. "The Advanced Grid Initiative dovetails nicely with the company's strategic priorities, including enhancing the customer experience and keeping bills low."

LEADING THE CLEAN ENERGY TRANSITION DOESN'T HAPPEN BY ACCIDENT. IT TAKES A TRACK RECORD OF OPERATIONAL EXCELLENCE, STRONG STAKEHOLDER ENGAGEMENT AND A BALANCED, THOUGHTFUL APPROACH TO DRIVE SIGNIFICANT CARBON REDUCTIONS WHILE ENSURING RELIABILITY AND AFFORDABILITY FOR CUSTOMERS.

By completing the Dakota Range Wind Farm near Watertown, S.D., in early 2022, Xcel Energy successfully completed the largest multi-state wind investment in the nation, adding 3,600 megawatts of new company-owned wind projects since 2017. Xcel Energy now has more than 11,000 megawatts of wind capacity on its system and is among a handful of companies to exceed the 10,000-megawatt threshold.

"Wind energy drives both economic and environmental benefits for our customers, while wind ownership provides an attractive investment return for our shareholders. We've proven that we can effectively build and operate wind farms as part of our Steel for Fuel growth strategy," said Paul Johnson, Vice President, Treasurer and Investor Relations. "We estimate our wind farms generated approximately $1.8 billion in savings for customers over the past five years. In addition, wind farms provide a strong tax base, along with both construction and permanent jobs, and landowner lease payments help drive the economy in rural communities."

Transitioning from fossil fuels to renewable energy sources like wind and solar has helped the company reduce carbon emissions 50% since 2005 and remain on pace for an 80% reduction by the end of the decade.

Specific plans to achieve that goal are now being finalized after the Minnesota Public Utilities Commission approved our clean energy proposal for the Upper Midwest system. They include retiring all coal plants in the region by 2030, extending the use of our carbon-free Monticello Nuclear Generating Station to 2040 and adding approximately 5,800 megawatts of wind and solar power. Natural gas would continue to be used as a bridge fuel to ensure reliability until new technologies are developed.

ON PACE FOR A CARBON-FREE FUTURE

COMPANY FINALIZING PLANS TO REDUCE CARBON EMISSIONS MORE THAN 85% IN MINNESOTA AND COLORADO BY 2030

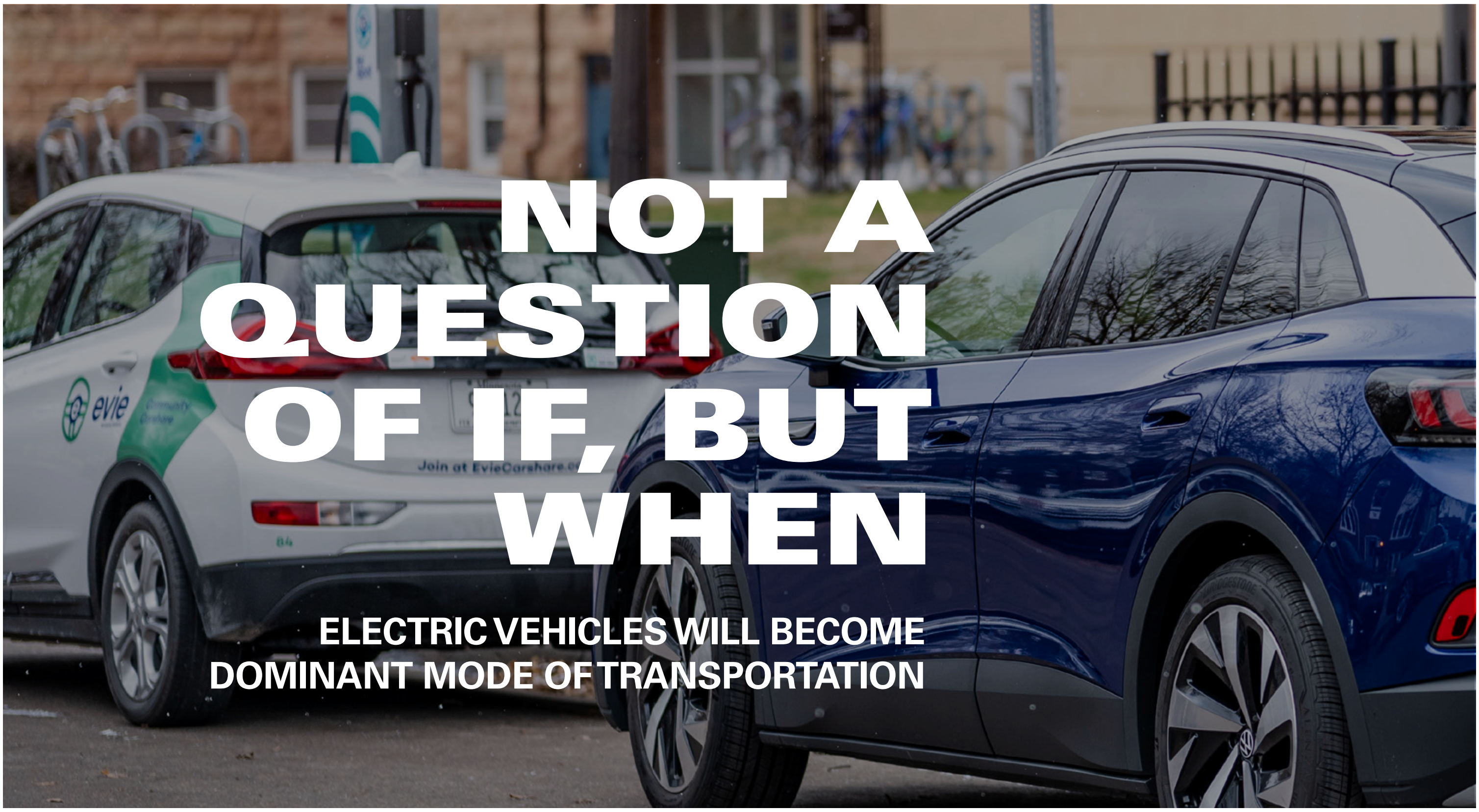
"The approved plan delivers more than 85% carbon reduction across our Upper Midwest system, while ensuring we continue to provide the reliable, affordable electricity our customers count on," said Chris Clark, President, Xcel Energy Minnesota, North Dakota and South Dakota. "Receiving commission approval for this transformational energy plan required significant outreach and dialogue with policymakers, customers and stakeholders; a process that takes years of planning and negotiating."

Meanwhile in Colorado, the company is expecting a commission decision by the end of first quarter 2022 on its landmark clean energy proposal, which is estimated to reduce carbon emissions 87% by the end of the decade and retire all its coal plants in the state by 2034. In addition, the company has received verbal approval for Colorado's Power Pathway, a nearly $2 billion transmission investment to improve the state's electric grid and deliver various proposed renewable energy projects to our customers. Once the written order is issued and work can begin, the transmission projects and new substations are expected to be completed starting in 2025 and continuing through 2027.

Achieving the company's industry-leading vision to produce carbon-free electricity for our customers by 2050 will require new clean energy technologies. One of the most promising emerging technologies is using carbon-free energy to produce hydrogen. Xcel Energy is partnering with the Department of Energy and the Idaho National Laboratory on a pilot project that is scheduled to begin producing carbon-free hydrogen at our Prairie Island Nuclear Generating Station next year that can be used in other applications.

In early 2022, Xcel Energy completed the largest multi-state wind investment in the country at the time — 14 wind farms in seven states. More wind projects are on the horizon in the recently approved Upper Midwest Resource Plan and proposed Colorado Energy Plan.

In 2020, the company created the Carbon-Free Technology Initiative, a cross-functional group set up to identify and support the future technologies critical to achieving our carbon-free goals. That work has now been expanded at the industry level by the Edison Electric Institute trade association.



NOT A QUESTION OF IF, BUT WHEN

ELECTRIC VEHICLES WILL BECOME DOMINANT MODE OF TRANSPORTATION

IN 2020, ELECTRIC VEHICLES (EVs) COMPRISED ONLY 3% OF VOLKSWAGEN'S GLOBAL NEW CAR SALES. BY 2030, VOLKSWAGEN PREDICTS A WHOPPING 50% OF ITS NEW CAR SALES WILL COME FROM EVs, ACCORDING TO REUTERS.

Europe's largest car manufacturer is investing $86 billion in EV technology, knowing that it's not a question of if — but when — EVs are the dominant mode of transportation across the globe.

Ford and General Motors have announced similar 2030 EV sales goals. In fact, demand for the new F-150 Lightning pickup truck, scheduled to come out in 2022, has been so intense that reservations have temporarily closed with a three-year waitlist, according to news reports.

Like the world's largest car manufacturers, Xcel Energy sees significant EV growth on the horizon, which will expand the company's clean energy leadership to the transportation sector, drive electricity sales growth and help keep bills low for customers. The company has set an aggressive goal to power 1.5 million electric vehicles in its eight-state service territory — or approximately 20% of the cars on the road — by the end of the decade.

"We know EV adoption will grow exponentially in the coming years, and we will be ready," said Nadia El Mallakh, who leads Xcel Energy's Clean Transportation team. "Our employees are working hard to make sure the transition to EVs is easy, seamless and less costly for our customers."

From a regulatory and policy perspective, the company made significant strides in 2021 — receiving final written approval for comprehensive, inaugural EV plans in both Colorado and New Mexico. Colorado's nation-leading $110 million Transportation Electrification Plan provides charging equipment for both single-family and multi-family homes and aligns with the state's goal to help place 940,000 EVs on Colorado roads by 2030. Broad and innovative, these plans focus on residential and business customers as well as our communities, while also embracing tools to bring electrification to all customers.

"We want to give everyone the opportunity to experience the benefits of EVs," El Mallakh said. "Income-qualified customers in Colorado can receive rebates on new and used EVs under $50,000,

and all Colorado customers have access to a rebate that essentially covers most of the home wiring costs to install a faster, more powerful home charger."

In addition to the strong regulatory and policy outcomes, the company launched a record number of clean transportation programs in Colorado and Minnesota last year — 14 to be exact.

In Minnesota, Xcel Energy is partnering with the cities of Minneapolis and St. Paul and the nonprofit Hourcar to build 70 curbside charging hubs across the metro area to support increased access and use of electric vehicles. Overall, the company is investing more than $30 million in public charging infrastructure across several states to provide more charging options for longer trips.

A new dedicated customer care team was created to tailor service for our new EV customers. The team helps customers find local EV dealers, directs them to tools to understand savings options and lines them up with hassle-free installation of a home charger by one of our certified program electricians through Xcel Energy's EV Accelerate At Home program. A separate, dedicated EV Advisor team helps commercial customers and municipalities find programs that best suit their needs and helps them evaluate the cost to transition all or part of their fleet of vehicles from gas to electric.

Xcel Energy customers can charge their EVs overnight at home using off-peak rates for the equivalent of about $1 per gallon of gas. Couple that with no oil changes and limited maintenance costs, and customers can save significant dollars as they drive past the gas station while simultaneously reducing their carbon footprint.

Rehana Power, an Xcel Energy customer, charges a Volkswagen ID.4 electric vehicle at an EV Spot charging station near Macalester College in St. Paul, Minnesota. The EV Spot network is a series of 70 curbside hubs that offer public access to the new all-electric Evie carshare service and the EV Spot electric charging stations.

Early adopters are already enjoying the economic and environmental benefits of driving electric. By 2030 under our aggressive vision, we expect our EV driving customers to collectively save $1 billion annually, while all our customers benefit from eliminating 5 million tons of carbon annually by the same year.

TWO YEARS AGO, XCEL ENERGY BEGAN A PIVOTAL EVOLUTION OF ITS SAFETY APPROACH TO FOCUS ON ELIMINATING SERIOUS INJURIES AND FATALITIES.

Safety Always aims to develop a culture of enhanced trust and transparency with employees and contractors, so that we can collaborate to identify the most serious risks inherent in our work and make sure that all the possible controls are in place to mitigate those risks before we start work.

Culture change has been a key focus in the first two years of implementing this approach. This includes preparing employees to make critical changes to how work is done every day and establishing the trust and transparency necessary for people to have open and honest conversations. Central to this change is conducting Event Learnings, which are candid conversations designed to provide a deep understanding of how an incident occurred so we can address what needs to be changed and improve together.

Collaborating to understand how work is truly performed in the field has allowed us to implement a new risk-based continuous improvement process to identify energy-based hazards and the critical controls needed to prevent life-ending and life-altering injuries from occurring.

"Everyone wants the same thing — to return home safely to their loved ones every night," said Jennifer Bailey, Director of Safety. "The most important strategy we can employ to prevent life-changing events from happening is to use controls — because they save lives. Our Safety Always approach is critical to ensuring that we have controls in place to prevent life-changing and life-ending injuries."

LEARNING NEW WAYS TO WORK

FOCUS ON SAFETY ALWAYS, INTRODUCING HYBRID WORK MODEL

Dora Solon, Operations Training Supervisor, adjusts a dial in the Control Room Simulator for the Monticello Nuclear Generating Station in Minnesota. Dora was among thousands of employees who continued to work safely onsite during the pandemic to provide energy for our customers.

COVID-19

Since the start of the pandemic, Xcel Energy has been working to protect the health and safety of our employees at all our facilities. Our health and safety strategy kept most office employees continuing to work from home throughout 2021, while our employees who work at our power plants, service centers and in the field served our customers onsite, all while following additional safety protocols.

Hybrid work program

This fall, the company's expanded leadership team began returning to their work locations to prepare for a full-scale return of all employees in 2022. As the entire workforce returns to their job sites in March 2022, the company is implementing a hybrid work program to offer eligible employees a mix of at-home and in-office work schedules. This hybrid approach ensures that valuable, in-person collaboration is embedded in the work culture and allows the flexibility that is critical to attracting and retaining top talent, especially in a tight labor market.

Corporate recognition

Xcel Energy has reached many milestones in 2021, among those included recognition for our company, our workplace and our commitment to living our values.

We were honored to be named among the World's Most Ethical Companies® by Ethisphere for the third consecutive year, reflecting the company's commitment to sustainability and ethical business practices. We also were among the Human Rights Campaign's Best Places to Work for LGBTQ Equality, earning a perfect score on its Corporate Equality Index for the sixth consecutive year.

We were named one of Fortune's Most Admired Companies for the ninth consecutive year and ranked second among energy providers. The company was also among Forbes' America's Best Large Employers, based on a survey of employees who rate their employers by describing how likely they would be to recommend them and identifying companies they admired.

ON THE HORIZON: NET-ZERO NATURAL GAS SERVICE

COMPANY WORKING TO REDUCE GREENHOUSE GAS EMISSIONS ACROSS THREE MAJOR ECONOMIC SECTORS

Gas fitter Debbra Trevino checks the pressure at a natural gas meter in Denver, Colorado.

After more than a year of study, Xcel Energy last fall announced a vision to achieve net-zero greenhouse gas emissions from its natural gas business by 2050. In doing so, the company became the first U.S. energy provider to announce a comprehensive vision with aggressive goals for reducing greenhouse gas emissions across three large sectors of the economy: electricity, natural gas use in buildings and transportation.

"Our vision for delivering net-zero energy by 2050 is an important evolution in our clean energy strategy," said Frank Prager, Xcel Energy's Chief Sustainability Officer. "As a clean energy leader, it's important that we have a plan for reducing our footprint across all areas of our business and provide customers a path to continue using reliable, affordable energy while reducing their emissions as well."

The new clean natural gas commitment builds on Xcel Energy's vision to deliver 100% carbon-free electricity to customers by 2050, with an aggressive interim goal of reducing emissions 80% by 2030. That vision, announced in 2018, led to dozens of U.S. power providers announcing similar goals to eliminate carbon from their electric systems. In 2020, we announced a goal to use our increasingly green product for powering 1.5 million electric vehicles in our service areas by the end of the decade.

Along with a net-zero natural gas commitment, we set an important interim goal to reduce greenhouse gas emissions from our natural gas service 25% from 2020 levels, including net-zero methane emissions on our own infrastructure by 2030. We will target three discrete segments of the natural gas value chain: our own natural gas infrastructure, our suppliers and their upstream infrastructure, and customer usage and emissions.

This clean energy transformation starts with our own system where significant progress has already been made to reduce methane emissions. We will increase our emissions detection and repair work and continue to make operational and system improvements. As we move up the supply chain, we will, over time, purchase only certified low-emissions gas from our suppliers.

And for our customers, we will offer new voluntary programs to reduce carbon emissions from their own natural gas use, through expanded conservation efforts and the use of electric appliances and low-carbon gas alternatives, including hydrogen and renewable natural gas. Xcel Energy is set to launch a series of pilots to test renewable natural gas, smart electric water heaters and air source heat pumps with customers, as well as test both hydrogen production and the blending of hydrogen in its natural gas delivery system.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2021 or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

001-3034
(Commission File Number)

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
414 Nicollet Mall Minneapolis Minnesota	**55401**
(Address of Principal Executive Offices)	(Zip Code)

612 330-5500
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $2.50 par value per share	XEL	Nasdaq Stock Market LLC

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. ☒ Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒ Yes

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of June 30, 2021, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $35,463,594,471.

As of Feb. 17, 2022, there were 544,213,730 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement for its 2022 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

ITEM 1 — BUSINESS

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

Capital Services	Capital Services, LLC
Eloigne	Eloigne Company
e prime	e prime inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
Operating companies	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

CPUC	Colorado Public Utilities Commission
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DSM	Demand side management
ECA	Retail electric commodity adjustment
FCA	Fuel clause adjustment
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PSIA	Pipeline system integrity adjustment
RES	Renewable energy standard
TCR	Transmission cost recovery

Other

AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ATM	At-the-market
BART	Best available retrofit technology
C&I	Commercial and Industrial
CAGR	Corporate annual growth rate
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CDD	Cooling degree-days
CEO	Chief executive officer
CFO	Chief financial officer
CIG	Colorado Interstate Gas Company, LLC
COEO	Colorado Energy Office
CON	Certificate of Need
COVID-19	Novel coronavirus
CUB	Citizens Utility Board
CWA	Clean Water Act
CWIP	Construction work in progress
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DECON	Decommissioning method where radioactive contamination is removed and safely disposed of at a requisite facility or decontaminated to a permitted level
DRIP	Dividend Reinvestment Program
EEI	Edison Electric Institute
EIP	Energy Impact Partners
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
ESG	Environmental, Social and Governance
ETR	Effective tax rate
EVs	Electric Vehicles
FASB	Financial Accounting Standards Board
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
HDD	Heating degree-days
INPO	Institute of Nuclear Power Operations
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producing entity
ISO	Independent System Operator
ITC	Investment Tax Credit
LP&L	Lubbock Power & Light
MEC	Mankato Energy Center
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
NAAQS	National Ambient Air Quality Standard
Native load	Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NOL	Net operating loss
NOPR	Notice of proposed rulemaking
O&M	Operating and maintenance
OAG	Minnesota Office of the Attorney General
OATT	Open Access Transmission Tariff
PFAS	Per- and PolyFluoroAlkyl Substances
PI	Prairie Island nuclear generating plant
Post-65	Post-Medicare
PPA	Purchased power agreement
Pre-65	Pre-Medicare
PTC	Production tax credit
REC	Renewable energy credit

ROE	Return on equity
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
THI	Temperature-humidity index
TO	Transmission owner
TSR	Total shareholder return
VaR	Value at Risk
VIE	Variable interest entity

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

Where to Find More Information

Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC.

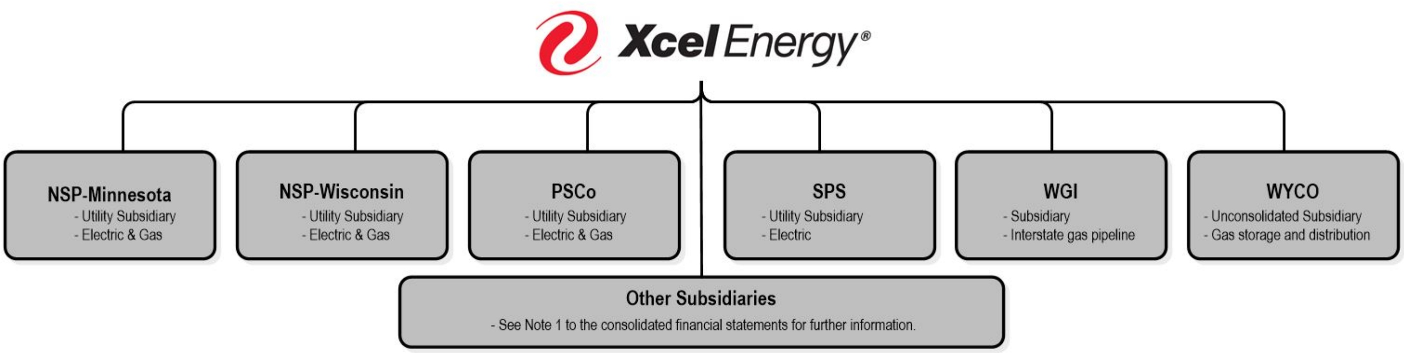
The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov. The information on Xcel Energy's website is not a part of, or incorporated by reference in, this annual report on Form 10-K. Xcel Energy intends to make future announcements regarding Company developments and financial performance through its website, www.xcelenergy.com, as well as through press releases, filings with the SEC, conference calls and webcasts.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to 2022 EPS guidance, long-term EPS and dividend growth rate objectives, future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 (including risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including potential workforce impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety, including our nuclear generation facilities and other utility operations; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; ability to recover costs; changes in regulation and subsidiaries' ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints and their impact on capital expenditures and/or the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties; and regulatory changes and/or limitations related to the use of natural gas as an energy source.

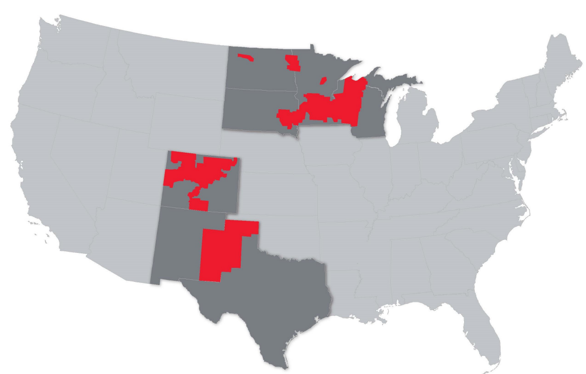
Overview

Xcel Energy (the "Company") is a major U.S. regulated electric and natural gas delivery company headquartered in Minneapolis, Minnesota (incorporated in Minnesota in 1909). Xcel Energy serves customers in eight mid-western and western states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Xcel Energy provides a comprehensive portfolio of energy-related products and services to approximately 3.7 million electric customers and 2.1 million natural gas customers through four utility subsidiaries (i.e., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS). Along with the utility subsidiaries, the transmission-only subsidiaries, WYCO (a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities) and WGI (an interstate natural gas pipeline company) comprise the regulated utility operations. Xcel Energy's nonregulated subsidiaries include Eloigne, Capital Services, Venture Holdings and Nicollet Project Holdings.



Utility Subsidiaries' Service Territory

Electric customers	3.7 million
Natural gas customers	2.1 million
Total assets	$57.9 billion
Electric generating capacity	20,653 MW
Natural gas storage capacity	53.4 Bcf
Electric transmission lines (conductor miles)	111,434 miles
Electric distribution lines (conductor miles)	210,470 miles
Natural gas transmission lines	2,293 miles
Natural gas distribution lines	36,510 miles



Strategy

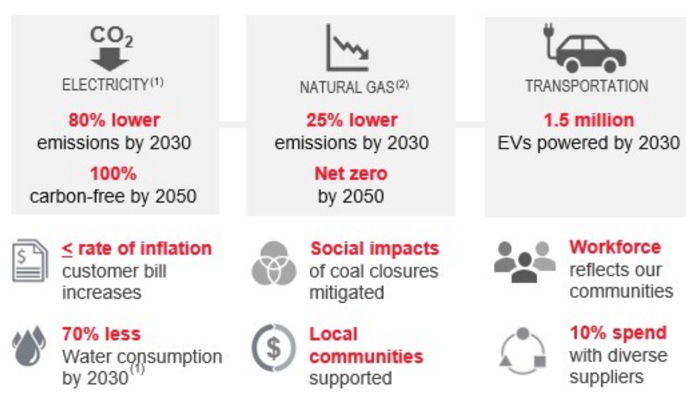
Xcel Energy strives to be the preferred and trusted provider of the energy our customers need, while offering a competitive total return to shareholders. We deliver on our vision through three strategic priorities:

LEAD THE CLEAN ENERGY TRANSITION | ENHANCE THE CUSTOMER EXPERIENCE | KEEP BILLS LOW

Sustainability is embedded in our strategy. We are retiring coal plants, adding renewables, exploring new technologies and helping to electrify other sectors, while maintaining customer affordability and supporting our employees and communities.

We are the first U.S. energy provider to set aggressive goals for reducing GHG emissions across three large sectors of the economy: electricity, natural gas use in buildings and transportation.

Our sustainability commitments include:



(1) Includes owned and purchased electricity provided to customers.
(2) Spans natural gas supply, distribution and customer use; includes net-zero methane emissions on our natural gas system by 2030.

We demonstrate environmental, social and governance leadership by engaging with stakeholders and mitigating risk, while staying committed to our customers, employees and communities.

Rooted in a culture of compliance and ethical conduct, our decisions and actions are guided by our Code of Conduct and our four values:

Connected **Committed** **Safe** **Trustworthy**

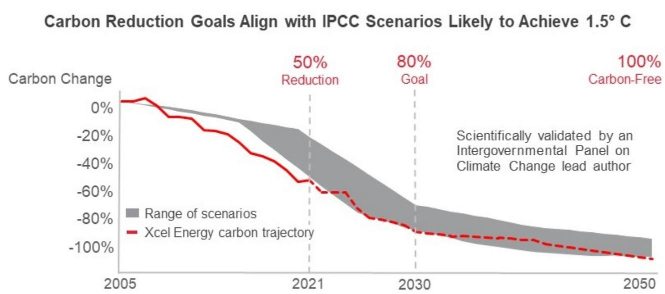
These values are reinforced by policies that govern safety practices, ethical standards and conduct, environmental performance, diversity and inclusion, political contributions, and other aspects of our business.

Our values, culture and Code of Conduct serve as the foundation upon which Xcel Energy's Board of Directors, employees, contractors and suppliers approach their work in delivering on our three strategic priorities.

Lead the Clean Energy Transition

For more than a decade, Xcel Energy has proactively managed the risk of climate change and worked to meet increasing demand for cleaner energy.

Xcel Energy was the first major U.S. utility to establish a carbon-free vision, targeting 100% carbon-free electricity by 2050 and an interim goal of 80% reduction in carbon emissions by 2030 (from 2005 levels), including owned and purchased power. A lead author for the IPCC confirmed that our vision aligns with science-based scenarios likely to limit global warming to 1.5 degrees Celsius from pre-industrial levels.



Goal includes owned and purchased power.

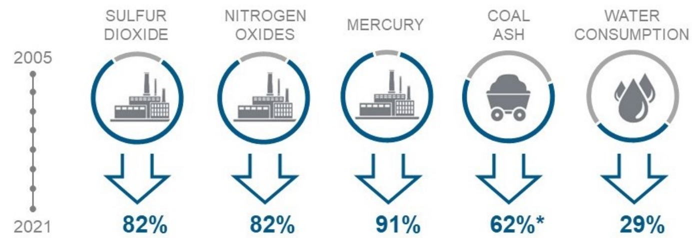
The pace of achieving a carbon-free vision is governed by reliability and customer affordability. Our filed resource plans outline a clear, transparent path to achieve an 80% carbon reduction using current technologies, while maintaining customer bill increases at or below the rate of inflation. Moving from 80% carbon reduction to 100% carbon-free electricity will require new dispatchable and scalable technologies that are economically viable, as well as supportive public policy. Resiliency and innovation also remain paramount to a successful transition, as does the economic vitality of our communities.

As we prepare for early coal plant retirements, we provide employees advanced notice and offer retraining and relocation opportunities, with no layoffs to date. We also help attract and make investments to offset community economic impacts. Xcel Energy has a long track record of working with our communities on energy, climate and environmental initiatives that impact them and has publicly committed to furthering environmental justice.

We consistently set aggressive goals and hold ourselves accountable to our customers, communities and investors, as well as, to our own values. Xcel Energy instituted oversight of environmental performance by the Board of Directors beginning in 2000 and was among the first U.S. utilities to tie carbon reduction to executive compensation over fifteen years ago.

Through 2021, we reduced carbon emissions from generation serving customers by an estimated 50% (from 2005 levels) and remain on track to achieve 80% carbon reduction by 2030.

Other notable environmental improvements include:

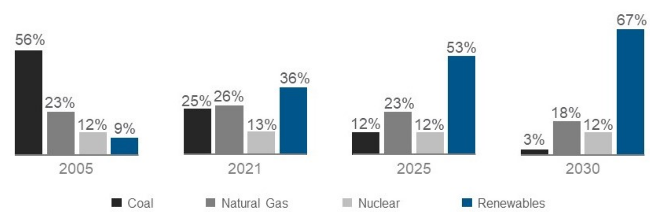


Results from owned generation except for water, which includes owned and purchased power.
* Coal ash reduction is as of 2020.

Xcel Energy has provided a voluntary, third-party verified annual GHG disclosure since 2005, longer than any other U.S. utility. We are a founding member of The Climate Registry and a supporter of the Task Force on Climate-Related Financial Disclosures. Our disclosures also align with the Global Reporting Initiative, Sustainability Accounting Standards Board and United Nations Sustainable Development Goals frameworks.

Since year-end 2020, we have completed four wind farms, adding ~800 MW (includes the Dakota Range project which went in service in January 2022) of owned wind to our system that provides significant environmental benefits and cost savings for our customers. Xcel Energy's wind capacity is now over 11,000 MW, including nearly 4,500 MW of owned wind.

By 2030, we project that approximately 80% of our energy will come from carbon-free resources.



Based on resource plans filed in Minnesota and Colorado, Xcel Energy anticipates nearly 10,000 MW of additional renewables over the next decade, and expects to be coal-free by 2034.

Colorado resource plan — settlement pending CPUC approval

- 87% carbon reduction by 2030 and full coal exit by 2034.
- ~3,900 MW of wind and solar additions.
- ~1,700 MW of flexible resources and storage.
- ~1,200 MW of distributed solar generation.

Minnesota resource plan — approved by MPUC

- 85% carbon reduction and full coal exit by 2030.
- 4,650 MW of wind and solar additions by 2032; the plan includes an additional 1,100 MW of renewables beyond 2032.
- Transmission infrastructure to connect new renewables to the grid.
- Extension of the Monticello nuclear plant through 2040.
- ~3,800 MW of firm peaking capacity for reliability before 2030, including hydrogen-ready combustion turbines, the combustion turbines will need to go through a CON process.
- Additional ~2,100 MW of firm capacity and storage post 2030, to be addressed in future proceedings.

Texas and New Mexico

- Proposed full coal exit by 2034 upon early retirement of our Tolk plant.
- Conversion of our Harrington coal plant to natural gas.

We plan to limit coal usage through dispatching units seasonally where possible. Natural gas and other dispatchable resources will be used as needed for reliability and resiliency as more renewables come on the system.

Significant transmission expansion will be required to enable future renewables. Our Pathway project (if approved) in Colorado will provide over 560 miles of transmission lines and enable nearly 5,500 MW of new renewables, including access to some of the region's richest wind resources. We also anticipate expansion in the Upper Midwest over the next decade as part of MISO's transmission expansion planning effort, creating investment opportunity.

Our clean energy leadership encompasses our natural gas business as well. In 2021, we committed to reduce GHG emissions by 25% by 2030 from 2020 levels and deliver net-zero natural gas service by 2050, including customer use.

Plans include:

- Influencing suppliers - pursue certified low/no net emissions supply.
- Operating the cleanest possible system – incorporate clean fuels.
- Offering customer options – encourage electrification, where beneficial.

Xcel Energy's leadership also extends beyond our electric and gas businesses to other parts of the economy. In addition to transitioning our own generation fleet, we are helping to decarbonize other sectors, starting with transportation. We aim to enable 1.5 million EVs across our states by 2030, representing a nearly $2 billion investment, 0.6% to 0.7% incremental annual retail sales growth and avoidance of roughly 5 million tons of CO_2 emissions annually.

Enhance the Customer Experience

Xcel Energy has a comprehensive suite of renewable and conservation programs that provide customers with clean energy options and help keep their bills low. We are also transforming and expanding our electric grid to accommodate increased load growth, renewable energy and distributed energy resources.

In 2021, Xcel Energy installed over 300,000 smart meters and plans to install more than one million in 2022. Xcel Energy also launched 12 EV programs for residential and commercial customers, received approval of our New Mexico plan, and continued to prepare for increased levels of EV adoption across our states.

For our local communities, we initiated 20 economic development projects in 2021, which are projected to lead to over $1 billion in capital investments and 5,000 jobs. Additionally, over 60% of our supply chain spend was local.

Keep Bills Low

Customer affordability is critical to successful strategy execution and we are working to keep bill increases at or below the rate of inflation. Since 2013, we have managed average residential bill growth to below 1% annually, with electric and natural gas bill increases of 0.8% and 0.3%, respectively.

Xcel Energy has invested more than $2 billion over the past decade in a comprehensive suite of conservation programs. We have kept O&M expenses flat since 2014, while adding significant renewables and without compromising safety or reliability.

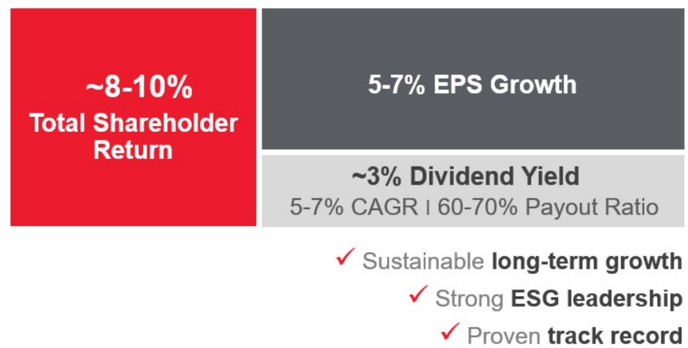
Xcel Energy continues to prudently invest in appropriate areas consistent with its continuing commitment to minimize costs through ongoing process and technology improvements.

Our geographic advantages in wind and solar also enable customer savings, which we call our "Steel for Fuel" strategy. High capacity factors, coupled with renewable tax credits and avoided fuel costs, enable Xcel Energy to add renewables while saving customers money. To date, we have delivered more than $1.8 billion in customer savings by adding owned wind to our system.

In addition to continued savings from economic renewables, disciplined cost control and future coal plant retirements, we anticipate sales growth from electric vehicles will help keep bills low for all customers in the long term, as well as provide customers with annual fuel savings (equivalent cost per gallon for fueling with electricity vs. gasoline) of approximately $1 billion by 2030.

Deliver a Competitive Total Return to Investors

Successful strategy execution, along with our disciplined approach to growth, operations and management of environmental, social and governance issues, positions us to continue delivering a competitive TSR.



We have consistently achieved our financial objectives, meeting or exceeding our initial earnings guidance range for 17 consecutive years and delivering dividend growth for 18 consecutive years.

Over the past five years, GAAP earnings have grown by 6% annually and our annual dividend growth was 6.1%. Xcel Energy works to maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range. Current ratings are consistent with this goal.

Human Capital

Xcel Energy employees are the driving force behind our Company's success. Our strategic, data-driven approach to workforce planning helps ensure we will continue to have the skills and capabilities required to meet the evolving needs of our business, customers and communities. We are also deeply committed to diversity, equity, human rights and safety.

Safety

Continuously elevating the quality and safety of the workplace is a top priority. We are considered a benchmark company for our Safety Always approach, focused on eliminating life-altering injuries through a trusted, transparent culture and the use of critical controls. All employees have "stop work authority" and are expected to keep each other, our customers and the public safe. Employees are encouraged to speak up, share experiences and learn from events to help protect themselves, their coworkers and the public.

The Board of Directors has oversight for employee and public safety through the Operations, Nuclear, Environmental and Safety committee, both of which are also tied to annual incentive compensation.

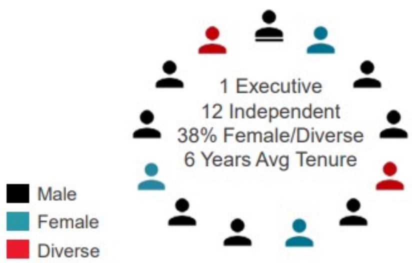
Benefits

Xcel Energy offers a competitive benefits package, including: performance-based compensation, supported by a management system that emphasizes ongoing coaching conversations. Benefits also include floating holidays and recognition, retirement and holistic well-being programs.

Management continuously evaluates benefits to maintain a market competitive, performance-based, shareholder-aligned total rewards package that supports our ability to attract, engage and retain a talented and diverse workforce, while reinforcing and rewarding strong performance.

Diversity, Equity, Inclusion and Human Rights

We aim to create an inclusive culture where employees are treated equitably, and diversity is not only accepted but celebrated. This starts with our Board of Directors, of which eight members were elected in the past five years.



The Board of Directors oversees our workforce strategy, including diversity and inclusion initiatives. In 2021, Xcel Energy added an incentive-based metric focused on diverse interview panels, executive sponsorship and employee feedback on inclusion in the workplace. A total of 70% of annual incentive pay was tied to safety, system reliability and diversity, equity and inclusion metrics.

In 2021, nearly all offers made had diverse hiring panels and executive sponsors consistently met with their employee counterparts at least monthly. We have also disclosed our Equal Employment Opportunity Employer Information Report (EEO-1).

Our CEO and senior executives lead by example, fostering an open and inclusive work environment through their interactions, communications and personal sponsorship of diverse talent throughout the organization.

We partner with educational and community organizations to attract and hire diverse employees who reflect the communities we serve and live our values. Workforce demographics as of December 2021 (unless noted):

	Female	Ethnically Diverse
Board of Directors [(a)]	23 %	15 %
CEO direct reports [(a)]	36 %	18 %
Management	22 %	11 %
Employees	24 %	17 %
New hires	39 %	26 %
Interns (hired throughout 2021)	34 %	27 %

(a) Demographics as of Feb. 1, 2022.

Veteran hiring is also a focus, with roughly 10% of employees having served in the military.

To help foster a culture of inclusivity, leaders and employees receive training on microinequities and unconscious bias. The Company hosts 11 business resource groups to support employee interests and obtain diverse perspectives when solving challenges and achieving goals.

Xcel Energy also respects employees' freedom of association and their right to collectively organize. As of Dec. 31, 2021, approximately 44% of our employees were covered by collective bargaining agreements.

	Employees Covered by Collective Bargaining Agreements	Total Full-Time Employees
NSP-Minnesota	2,020	3,083
NSP-Wisconsin	382	518
PSCo	1,818	2,314
SPS	736	1,099
XES	—	4,307
Total	4,956	11,321

Employee turnover for 2021 and future projected retirement eligibility:

Employee Turnover	
Bargaining	7 %
Non-Bargaining	15 %
Overall [(a)]	12 %

Retirement Eligibility	
Within next 5 years	26 %
Within next 10 years	40 %

(a) 31% of turnover was due to retirements.

Xcel Energy has publicly confirmed our commitment to the advancement and protection of human rights, consistent with U.S. human rights laws and the general principles in the International Labour Organization Conventions. Code of Conduct training is required for all employees annually and the Board of Directors.

The Company does not tolerate Code violations or other unacceptable behaviors. We expect and offer employees multiple avenues to raise concerns or report wrong-doing and do not permit any retaliation.

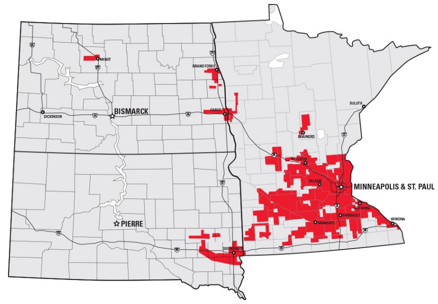
Xcel Energy recently received the following recognitions:

Fortune	Human Rights Campaign	GI Jobs	Military Times
World's Most Admired Companies	Best Places to Work for LGBTQ Equality	Military Friendly Employer	Best for Vets

Utility Subsidiaries

NSP-Minnesota

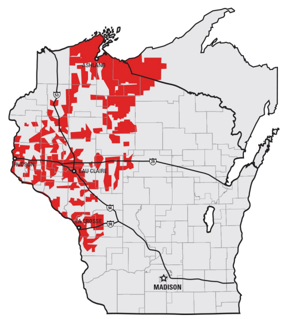
Electric customers	1.5 million
Natural gas customers	0.5 million
Total assets	$22.8 billion
Rate Base (estimated)	$13.7 billion
ROE (net income / average stockholder's equity)	8.45%
Electric generating capacity	8,628 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	34,155 miles
Electric distribution lines (conductor miles)	81,406 miles
Natural gas transmission lines	85 miles
Natural gas distribution lines	10,741 miles



NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSP-Wisconsin

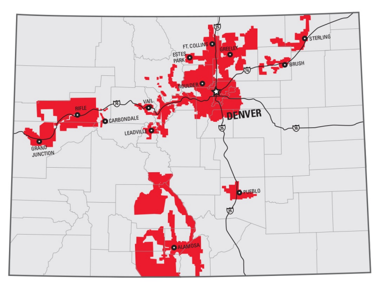
Electric customers	0.3 million
Natural gas customers	0.1 million
Total assets	$3.1 billion
Rate Base (estimated)	$2.0 billion
ROE (net income / average stockholder's equity)	9.92%
Electric generating capacity	548 MW
Gas storage capacity	3.8 Bcf
Electric transmission lines (conductor miles)	12,409 miles
Electric distribution lines (conductor miles)	27,701 miles
Natural gas transmission lines	3 miles
Natural gas distribution lines	2,526 miles



NSP-Wisconsin conducts business in Wisconsin and Michigan and generates, transmits, distributes and sells electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

PSCo

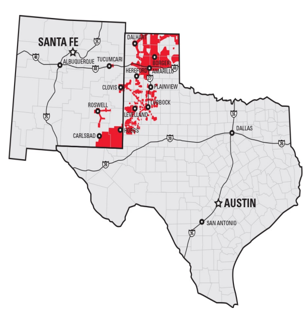
Electric customers	1.5 million
Natural gas customers	1.5 million
Total assets	$22.0 billion
Rate Base (estimated)	$14.0 billion
ROE (net income / average stockholder's equity)	8.23%
Electric generating capacity	6,228 MW
Gas storage capacity	32.5 Bcf
Electric transmission lines (conductor miles)	24,116 miles
Electric distribution lines (conductor miles)	78,712 miles
Natural gas transmission lines	2,174 miles
Natural gas distribution lines	23,243 miles



PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

SPS

Electric customers	0.4 million
Total assets	$9.3 billion
Rate Base (estimated)	$6.4 billion
ROE (net income / average stockholder's equity)	9.22%
Electric generating capacity	5,249 MW
Electric transmission lines (conductor miles)	40,754 miles
Electric distribution lines (conductor miles)	22,651 miles



SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.

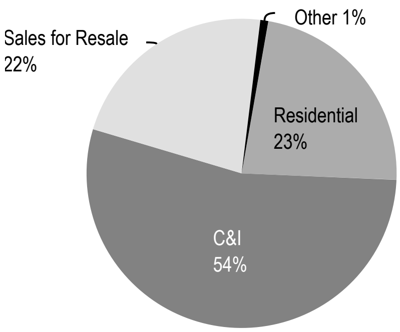
Operations Overview

Utility operations are generally conducted as either electric or gas utilities in our four utility subsidiaries.

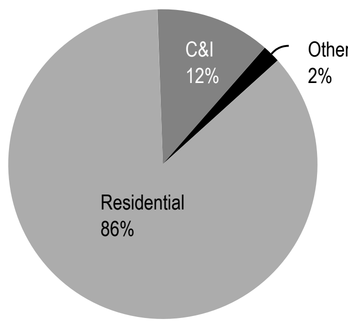
Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities across all four operating companies. Xcel Energy had electric sales volume of 115,474 (millions of KWh), 3.7 million customers and electric revenues of $11,205 (millions of dollars) for 2021.

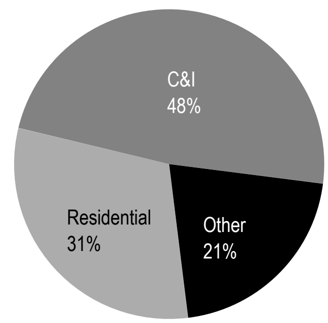
Sales Volume



Number of Customers



Revenues

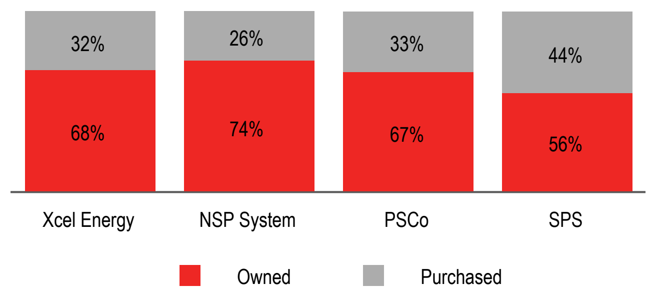


Retail Sales/Revenue Statistics [(a)]

	2021	2020
KWh sales per retail customer	23,968	23,910
Revenue per retail customer	$ 2,405	$ 2,199
Residential revenue per KWh	12.94 ¢	12.12 ¢
Large C&I revenue per KWh	6.60 ¢	5.78 ¢
Small C&I revenue per KWh	10.47 ¢	9.56 ¢
Total retail revenue per KWh	10.03 ¢	9.20 ¢

(a) See Note 6 to the consolidated financial statements for further information.

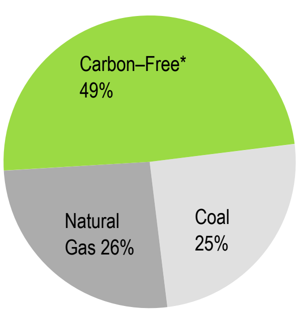
Owned and Purchased Energy Generation — 2021



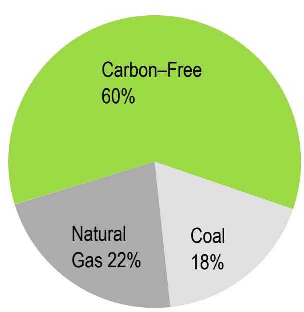
Electric Energy Sources

Total electric energy generation by source (including energy market purchases) for the year ended Dec. 31, 2021:

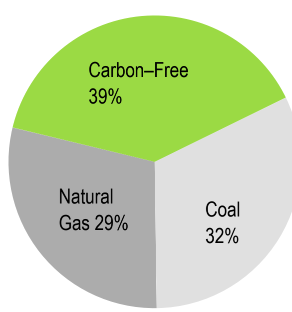
Xcel Energy



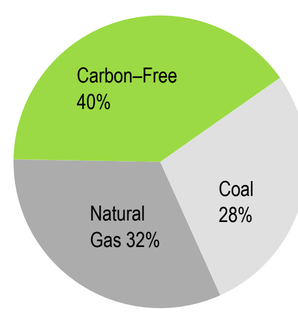
NSP System



PSCo



SPS



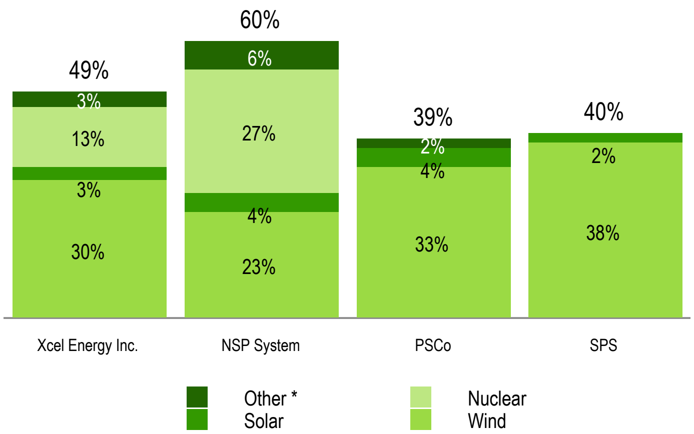
* Distributed generation from the Solar*Rewards® program is not included (approximately 666 million KWh for 2021).

Carbon-Free

Xcel Energy's carbon-free energy portfolio includes wind, nuclear, hydroelectric, biomass and solar power from both owned generation facilities and PPAs. Carbon-free percentages will vary year-over-year based on system additions, commodity costs, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Carbon-free energy as a percentage of total energy for 2021:



* Includes biomass and hydroelectric.

Wind

Owned — Owned and operated wind farms with corresponding capacity:

Utility Subsidiary	2021 Wind Farms	2021 Capacity (MW) [(a)]	2020 Wind Farms	2020 Capacity (MW) [(b)]
NSP System	14	2,031	11	1,540
PSCo	2	1,059	2	1,059
SPS	2	984	2	967
Total	18	4,075	15	3,566

(a) Summer 2021 net dependable capacity.
(b) Summer 2020 net dependable capacity.

PPAs — Number of PPAs with capacity range:

Utility Subsidiary	2021 PPAs	2021 Range (MW)	2020 PPAs	2020 Range (MW)
NSP System	128	1 — 206	129	1 — 206
PSCo	17	23 — 301	17	23 — 301
SPS	17	1 — 250	18	1 — 250

Capacity — Wind capacity (MW):

Utility Subsidiary	2021	2020
NSP System	3,997	3,348
PSCo	4,085	4,085
SPS	2,548	2,535

Average Cost (Owned) — Average cost per MWh of wind energy from owned generation:

Utility Subsidiary	2021	2020
NSP System	$ 25	$ 23
PSCo	17	35
SPS	17	17

Average Cost (PPAs) — Average cost per MWh of wind energy under existing PPAs:

Utility Subsidiary	2021	2020
NSP System	$ 37	$ 38
PSCo	35	40
SPS	27	26

Wind Development

Xcel Energy placed approximately 500 MW of owned wind and approximately 255 MW of PPAs into service during 2021:

Project	Utility Subsidiary	Capacity (MW)
Blazing Star 2	NSP-Minnesota	200 [(a)(b)]
Freeborn	NSP-Minnesota	200 [(a)(b)]
Mower	NSP-Minnesota	91 [(a)(b)]
Various PPAs	Various	~255 [(c)]

(a) Summer 2021 net dependable capacity.
(b) Values disclosed are the maximum generation levels. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(c) Based on contracted capacity.

Xcel Energy currently has approximately 1,050 MW of owned wind under development or being repowered. In addition, we expect to add approximately 200 MW of planned PPAs.

Project	Utility Subsidiary	Capacity (MW)	Estimated Completion
Northern Wind	NSP-Minnesota	100	2022
Nobles	NSP-Minnesota	200	2022
Dakota Range	NSP-Minnesota	300	2022 [(a)]
Grand Meadow	NSP-Minnesota	100	2023
Border Winds	NSP-Minnesota	150	2025
Pleasant Valley	NSP-Minnesota	200	2025
Various PPAs	Various	~200	2022

(a) Placed in service in January 2022.

Solar

Solar PPA(s):

Type	Utility Subsidiary	Capacity (MW)
Distributed Generation	NSP System	994
Utility-Scale	NSP System	268
Distributed Generation	PSCo	736
Utility-Scale	PSCo	562
Distributed Generation	SPS	15
Utility-Scale	SPS	192
Total		2,767

Average Cost (PPAs) — Average cost per MWh of solar energy under existing PPAs:

Utility Subsidiary	2021	2020
NSP System	$ 90	$ 90
PSCo	67	89
SPS	61	59

Solar Development

In June 2021, the PSCW approved NSP-Wisconsin's request to purchase the 74 MW Western Mustang build-own-transfer solar facility for approximately $100 million. Also, as part of the Minnesota Recovery and Relief Recovery docket, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an incremental investment of approximately $575 million. An MPUC decision is expected by the third quarter of 2022.

PSCo placed approximately 260 MW of PPAs into service during 2021.

Nuclear

Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2021 net summer dependable capacity that serves the NSP System. Our nuclear fleet has become one of the best performing and dependable in the nation, as rated by both the NRC and INPO. Xcel Energy secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. We use varying contract lengths as well as multiple producers for uranium concentrates, conversion services and enrichment services to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

Nuclear Fuel Cost

Delivered cost per MMBtu of nuclear fuel consumed for owned electric generation and the percentage of total fuel requirements:

Utility Subsidiary	Nuclear	
NSP System	Cost	Percent
2021	$ 0.77	46 %
2020	0.80	51

Other

Xcel Energy's other carbon-free energy portfolio includes hydro from owned generating facilities.

See Item 2 — Properties for further information.

Fossil Fuel

Xcel Energy's fossil fuel energy portfolio includes coal and natural gas power from both owned generating facilities and PPAs.

Coal

Xcel Energy owns and operates coal units with approximately 6,500 MW of total 2021 net summer dependable capacity.

Approved early coal plant retirements:

Year	Utility Subsidiary	Plant Unit	Capacity (MW)
2022	PSCo	Comanche 1	325
2023	NSP-Minnesota	Sherco 2	682
2024	SPS	Harrington [(a)]	1,018
2025	PSCo	Comanche 2	335
2025	PSCo	Craig 1	42 [(b)]
2026	NSP-Minnesota	Sherco 1	680
2028	PSCo	Craig 2	40 [(b)]
2028	NSP-Minnesota	A.S. King	511
2030	NSP-Minnesota	Sherco 3	517 [(b)]

(a) Reflects expected conversion from coal to natural gas following the TCEQ order that Harrington cease use of coal fuel by Jan. 1, 2025, pending PUCT and NMPRC review.
(b) Based on Xcel Energy's ownership interest.

Proposed

Year	Utility Subsidiary	Plant Unit	Capacity (MW)
2025	PSCo	Pawnee [(a)]	505
2027	PSCo	Hayden 2	98 [(b)]
2028	PSCo	Hayden 1	135 [(c)]
2034	SPS	Tolk 1	532
2034	SPS	Tolk 2	535
2034	PSCo	Comanche 3	500 [(d)]

(a) Reflects conversion from coal to natural gas.
(b) Based on PSCo's ownership of 37% of Unit 2.
(c) Based on PSCo's ownership of 76% of Unit 1.
(d) Based on PSCo's ownership of 67%.

Coal Fuel Cost

Delivered cost per MMBtu of coal consumed for owned electric generation and the percentage of fuel requirements:

	Coal [(a)]	
Utility Subsidiary	Cost	Percent
NSP System		
2021	$ 1.60	39 %
2020	1.97	31
PSCo		
2021	1.43	62
2020	1.41	51
SPS		
2021	2.07	66
2020	2.28	40

(a) Includes refuse-derived fuel and wood for the NSP System.

Natural Gas

Xcel Energy has 22 natural gas plants with approximately 7,900 MW of total 2021 net summer dependable capacity.

Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Natural Gas Cost

Delivered cost per MMBtu of natural gas consumed for owned electric generation and the percentage of total fuel requirements:

	Natural Gas	
Utility Subsidiary	Cost	Percent
NSP System		
2021 [(a)]	$ 4.98	15 %
2020	2.67	17
PSCo		
2021 [(a)]	8.38	38
2020	3.01	49
SPS		
2021 [(a)]	6.72	34
2020	1.43	60

(a) Reflective of Winter Storm Uri.

Capacity and Demand

Uninterrupted system peak demand and occurrence date for the regulated utilities:

	System Peak Demand (MW)			
	2021		2020	
NSP System	8,837	June 9	8,571	July 8
PSCo	6,958	July 28	6,899	Aug. 17
SPS	4,054	Aug. 9	4,195	July 14

Transmission

Transmission lines deliver electricity at high voltages and over long distances from power sources to transmission substations closer to customers. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy. Xcel Energy owns more than 111,000 conductor miles of transmission lines, serving 22,000 MW of customer load, across its service territory.

Transmission projects completed in 2021 include:

Project	Utility Subsidiary	Miles	Size (KV)
Hibbing Taconite Relocation	NSP-Minnesota	3	500
Huntley - Wilmarth	NSP-Minnesota	50	345
Helena Scott County	NSP-Minnesota	16	345
Centerville to Lincoln County	NSP-Minnesota	14	69
Turtle Lake Almena	NSP-Wisconsin	4	69
Roadrunner-China Draw	SPS	41	345

Notable upcoming projects:

Project	Utility Subsidiary	Miles	Size (KV)	Completion Date
Baytown to Long Lake	NSP-Minnesota	9	115	2022
Bird Island - Atwater - Big Swan	NSP-Minnesota	68	69	2022
Pipestone - Tracy	NSP-Minnesota	46	69	2022
Line Rebuild - Central	NSP-Minnesota	24	69	2022
West St. Cloud to Millwood Tap	NSP-Minnesota	24	69	2022
Bayfield Second Circuit	NSP-Wisconsin	19	35	2022
Colorado Energy Plan	PSCo	15	345	2022
Tolk Plant Substation				
Bus Reconfiguration	SPS	n/a	345, 230	2022
Twist to Wilco Line	SPS	4	115	2024
Pathway	PSCo	560	345	2027

See Item 2 - Properties for further information.

Distribution

Distribution lines allow electricity to travel at lower voltages from substations directly to customers. Xcel Energy has a vast distribution network, owning and operating approximately 210,000 conductor miles of distribution lines across our eight-state service territory.

To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure. Over the multi-year project that started in 2016, Xcel Energy plans to invest approximately $1.7 billion implementing new network infrastructure, smart meters, advanced software, equipment sensors and related data analytics capabilities. To date, Xcel Energy has spent approximately $568 million on these investments.

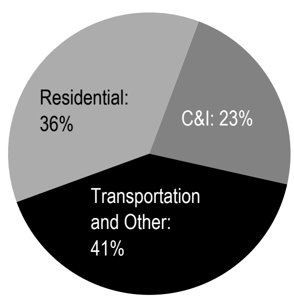
Investments of this nature will further improve reliability and reduce outage restoration times for our customers, while at the same time enabling new options and opportunities for increased efficiency savings. The new capabilities will also enable integration of battery storage and other distributed energy resources into the grid, including electric vehicles.

See Item 2 - Properties for further information.

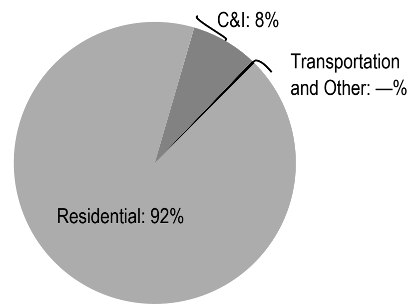
Natural Gas Operations

Natural gas operations consist of purchase, transportation and distribution of natural gas to end-use residential, C&I and transport customers in NSP-Minnesota, NSP-Wisconsin and PSCo. Xcel Energy had natural gas deliveries of 405,895 (thousands of MMBtu), 2.1 million customers and natural gas revenues of $2,132 (millions of dollars) for 2021.

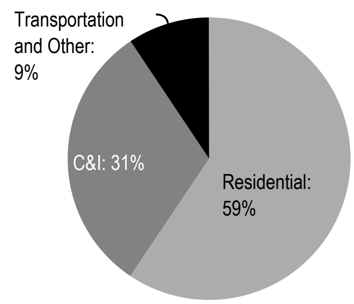
Deliveries



Number of Customers



Revenues



Sales/Revenue Statistics [(a)]

	2021	2020
MMBtu sales per retail customer	114	118
Revenue per retail customer	$ 917	$ 720
Residential revenue per MMBtu	8.61	6.64
C&I revenue per MMBtu	7.20	5.22
Transportation and other revenue per MMBtu	1.20	0.67

(a) See Note 6 to the consolidated financial statements for further information.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply).

Maximum daily output (firm and interruptible) and occurrence date:

	2021		2020	
Utility Subsidiary	MMBtu	Date [(a)]	MMBtu	Date
NSP-Minnesota	899,133	Feb. 11	871,921	Jan. 16
NSP-Wisconsin	167,656	Feb. 11	150,320	Dec. 24
PSCo	2,316,283	Feb. 14	1,931,888	Feb. 4

(a) Reflective of Winter Storm Uri.

Natural Gas Supply and Cost

Xcel Energy seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which increase flexibility, decrease interruption, financial risks and customer rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their states' commissions.

Average delivered cost per MMBtu of natural gas for regulated retail distribution:

Utility Subsidiary	2021 [(a)]	2020
NSP-Minnesota	$ 7.48	$ 3.32
NSP-Wisconsin	7.11	3.08
PSCo	6.06	2.52

(a) Reflective of Winter Storm Uri.

NSP-Minnesota, NSP-Wisconsin and PSCo have natural gas supply transportation and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery.

General

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Management cannot predict the impact of fluctuating energy prices, pandemics, terrorist activity, war or the threat of war. We could experience a material impact to our results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates or inflation.

Seasonality

Demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

Competition

Xcel Energy is subject to public policies that promote competition and development of energy markets. Xcel Energy's industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them.

Several states have incentives for the development of rooftop solar, community solar gardens and other distributed energy resources. Distributed generating resources are potential competitors to Xcel Energy's electric service business with these incentives and federal tax subsidies.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. Xcel Energy's wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load.

FERC Order No. 1000 established competition for ownership of certain new electric transmission facilities under Federal regulations. Some states have state laws that allow the incumbent a Right of First Refusal to own these transmission facilities.

FERC Order 2222 requires that RTO and ISO markets allow participation of aggregations of distributed energy resources. This order is expected to incentivize distributed energy resource adoption, however implementation is expected to vary by RTO/ISO and the near, medium, and long-term impacts of Order 2222 remain unclear.

Xcel Energy Inc.'s utility subsidiaries have franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power or gas, such as municipalization.

While each utility subsidiary faces these challenges, Xcel Energy believes their rates and services are competitive with alternatives currently available.

Governmental Regulations

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid and hazardous wastes or substances. Certain Xcel Energy activities require registrations, permits, licenses, inspections and approvals from these agencies.

Xcel Energy has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities strive to operate in compliance with applicable environmental standards and related monitoring and reporting requirements.

However, it is not possible to determine what additional facilities or modifications of existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of MGP and other sites.

Xcel Energy must comply with emission levels in Minnesota, Texas and Wisconsin that may require the purchase of emission allowances. The Denver North Front Range Non-attainment Area does not meet the ozone NAAQS. Colorado will continue to consider further reductions available in the non-attainment area as it develops plans to meet ozone standards. Natural gas plants which operate in PSCo's non-attainment area may be required to improve or add controls, implement further work practices and/ or enhanced emissions monitoring as part of future Colorado state plans.

There are significant environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. We have undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Future environmental regulations may result in substantial costs.

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for GHG reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision would allow the EPA to proceed with alternate regulation of coal-fired power plants. However, the Court of Appeals decision is now before the U.S. Supreme Court, where the Court is expected to rule on the nature and extent of the EPA's GHG regulatory authority. If any new rules require additional investment, Xcel Energy believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

In October 2020, the TCEQ approved an agreement that SPS will convert the Harrington plant from coal to natural gas by Jan. 1, 2025. This conversion is necessary to attain Federal Clean Air Act standards for emissions of SO_2.

Xcel Energy seeks to address climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner.

Emerging Environmental Regulation

New regulations and legislation are being considered to regulate PFAS in drinking water, water discharges, commercial products, wastes, and other areas. PFAS are man-made chemicals found in many consumer products that can persist and accumulate in the environment. These chemicals have received heightened attention from environmental regulators. Increased regulation of PFAS and other emerging contaminants at the federal, state, and local level could have a potential adverse effect on our operations but at this time, it is uncertain what impact, if any, there will be on our operations, financial condition or cash flows. Xcel Energy will continue to monitor these regulatory developments and their potential impact on its operations.

Environmental Costs

Environmental costs include amounts for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions.

Costs charged to operating expenses for nuclear decommissioning, spent nuclear fuel disposal, environmental monitoring and remediation and disposal of hazardous materials and waste were approximately:

- $365 million in 2021.
- $400 million in 2020.
- $345 million in 2019.

Average annual expense of approximately $425 million from 2022 – 2026 is estimated for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements were approximately:

- $60 million in 2021.
- $30 million in 2020.
- $30 million in 2019.

Other

Our operations are subject to workplace safety standards under the Federal Occupational Safety and Health Act of 1970 ("OSHA") and comparable state laws that regulate the protection of worker health and safety. In addition, the Company is subject to other government regulations impacting such matters as labor, competition, data privacy, etc. Based on information to date and because our policies and business practices are designed to comply with all applicable laws, we do not believe the effects of compliance on our operations, financial condition or cash flows are material.

Capital Spending and Financing

See Item 7 for discussion of capital expenditures and funding sources.

Executive Officers [(a)]

Name	Age [(b)]	Current and Recent Positions	Time in Position
Robert C. Frenzel	51	Chairman of the Board of Directors, Xcel Energy Inc.	December 2021 — Present
		President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2021 — Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	August 2021 — Present
		President and Chief Operating Officer, Xcel Energy Inc.	March 2020 — August 2021
		Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 — March 2020
		Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. [(c)]	February 2012 — April 2016
Brett C. Carter [(d)]	55	Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 — Present
		Senior Vice President and Shared Services Executive, Bank of America, an institutional investment bank and financial services company	October 2015 — May 2018
Patricia Correa	48	Senior Vice President, Chief Human Resources Officer, Xcel Energy Inc.	February 2022 — Present
		Senior Vice President, Human Resources, Eaton Corporation, a power management company	July 2019 — January 2022
		Vice President, Human Resources, Eaton Corporation	March 2016 — July 2019
		Senior Director, Talent & Organization Development, Kellogg Company, a food manufacturing company	July 2015 — March 2016
Timothy O'Connor	62	Executive Vice President, Chief Operations Officer, Xcel Energy Inc.	August 2021 — Present
		Executive Vice President, Chief Generation Officer, Xcel Energy Inc.	March 2020 — August 2021
		Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc	February 2013 — March 2020
Frank Prager	59	Senior Vice President, Strategy, Planning and External Affairs, Xcel Energy Inc.	March 2020 — Present
		Vice President, Policy and Federal Affairs, Xcel Energy Services Inc.	January 2015 — March 2020
Amanda Rome	41	Executive Vice President, General Counsel, Xcel Energy Inc.	June 2020 — Present
		Vice President and Deputy General Counsel, Xcel Energy Services Inc.	October 2019 — June 2020
		Managing Attorney, Xcel Energy Services Inc.	July 2018 — October 2019
		Rotational Position, Xcel Energy Services Inc.	January 2018 — July 2018
		Lead Assistant General Counsel, Xcel Energy Services Inc.	July 2015 — January 2018
Jeffrey S. Savage [(e)]	50	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 — Present
Brian J. Van Abel	40	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	March 2020 — Present
		Senior Vice President, Finance and Corporate Development, Xcel Energy Services Inc.	September 2018 — March 2020
		Vice President, Treasurer, Xcel Energy Services Inc.	July 2015 — September 2018

(a) No family relationships exist between any of the executive officers or directors.

(b) Ages as of Feb. 23, 2022.

(c) In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including Texas Competitive Energy Holdings the parent company of Luminant, filed a voluntary bankruptcy petition under Chapter 11 of the United States Bankruptcy Code. Texas Competitive Energy Holdings emerged from Chapter 11 in October 2016.

(d) Effective March 1, 2022, Mr. Carter will assume the role of Executive Vice President, Group President, Utilities, and Chief Customer Officer.

(e) Effective March 1, 2022, Mr. Savage will assume the role of Chief Audit and Financial Services Officer and will no longer be serving as an executive officer.

ITEM 1A — RISK FACTORS

Xcel Energy is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. These risks should be carefully considered together with the other information set forth in this report and future reports that we file with the SEC. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized.

While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Oversight of Risk and Related Processes

The Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors' committees have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors.

Xcel Energy maintains a robust compliance program and promotes a culture of compliance beginning with the tone at the top. The risk mitigation process includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management. Xcel Energy further mitigates inherent risks through formal risk committees and corporate functions such as internal audit, and internal controls over financial reporting and legal.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and risk analysis occurs formally through risk assessment conducted by senior management, the financial disclosure process, hazard risk procedures, internal audit and compliance with financial and operational controls.

Management also identifies and analyzes risk through the business planning process, development of goals and establishment of key performance indicators, including identification of barriers to implementing Xcel Energy's strategy. The business planning process also identifies likelihood and mitigating factors to prevent the assumption of inappropriate risk to meet goals.

Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors, providing information on the risks that management believes are material, including financial impact, timing, likelihood and mitigating factors. The Board of Directors regularly reviews management's key risk assessments, which includes areas of existing and future macroeconomic, financial, operational, policy, environmental and security risks.

The oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors' governance of Xcel Energy. The Board of Directors assigns oversight of critical risks to each of its four committees to ensure these risks are well understood and given appropriate focus.

The Audit Committee is responsible for reviewing the adequacy of the committee's risk oversight and affirming appropriate aggregate oversight occurs. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board of Directors for consideration when deemed appropriate.

New risks are considered and assigned as appropriate during the annual Board of Directors and committee evaluation process, resulting in updates to the committee charters and annual work plans. Additionally, the Board of Directors conducts an annual strategy session where Xcel Energy's future plans and initiatives are reviewed.

Operational Risks

Our natural gas and electric generation/transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages.

These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses to employees, third-party contractors, customers or the public. We maintain insurance against most, but not all, of these risks and losses.

The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows as well as potential loss of reputation.

Other uncertainties and risks inherent in operating and maintaining Xcel Energy's facilities include, but are not limited to:

- Risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned.
- Failures in the availability, acquisition or transportation of fuel or other necessary supplies.
- The impact of unusual or adverse weather conditions and natural disasters, including, but not limited to, tornadoes, icing events, floods and droughts.
- Performance below expected or contracted levels of output or efficiency (e.g., performance guarantees).
- Availability of replacement equipment.
- Availability of adequate water resources and ability to satisfy water intake and discharge requirements.
- Inability to identify, manage properly or mitigate equipment defects.
- Use of new or unproven technology.
- Risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation and lack of available alternative fuel sources.
- Increased competition due to, among other factors, new facilities, excess supply, shifting demand and regulatory changes.

Additionally, compliance with existing and potential new regulations related to the operation and maintenance of our natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with these regulations and systematically monitor and renew infrastructure over time, however, a significant incident or material finding of non-compliance could result in penalties and higher costs of operations.

Our natural gas and electric transmission and distribution operations are dependent upon complex information technology systems and network infrastructure, the failure of which could disrupt our normal business operations, which could have a material adverse effect on our ability to process transactions and provide services.

Our utility operations are subject to long-term planning and project risks.

Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of in-service dates and typically subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. Xcel Energy's long-term resource plan is dependent on our ability to obtain required approvals, develop necessary technical expertise, allocate and coordinate sufficient resources and adhere to budgets and timelines.

In addition, the long-term nature of both our planning and our asset lives are subject to risk. The electric utility sector is undergoing significant change (e.g., increases in energy efficiency, wider adoption of distributed generation and shifts away from fossil fuel generation to renewable generation). Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, and potentially stranded costs if we are not able to fully recover costs and investments.

The magnitude and timing of resource additions and changes in customer demand may not coincide with evolving customer preference for generation resources and end-uses, which introduces further uncertainty into long-term planning. Efforts to electrify the transportation and building sectors to reduce GHG emissions may result in higher electric demand and lower natural gas demand over time. Higher electric demand may require us to adopt new technologies and make significant transmission and distribution investments including advanced grid infrastructure, which increases exposure to overall grid instability and technology obsolescence. Evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may impact our resource mix and put pressure on our ability to recover capital investments in natural gas generation and delivery. Multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We are subject to longer-term availability of inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

Our utilities are highly dependent on suppliers to deliver components in accordance with short and long-term project schedules.

Our products contain components that are globally sourced from suppliers who, in turn, source components from their suppliers. A shortage of key components in which an alternative supplier is not identified could significantly impact project plans. Such impacts could include timing of projects, including potential for project cancellation. Failure to adhere to project budgets and timelines could adversely impact our results of operations, financial condition or cash flows.

We are subject to commodity risks and other risks associated with energy markets and energy production.

In the event fuel costs increase, customer demand could decline and bad debt expense may rise, which may have a material impact on our results of operations. Despite existing fuel recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows and liquidity.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs and supply shortages may not be fully resolved, which could cause disruptions in our ability to provide services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process. Also, significantly higher energy or fuel costs relative to sales commitments could negatively impact our cash flows and results of operations.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk.

Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability. The management of risks associated with hedging and trading is based, in part, on programs and procedures which utilize historical prices and trends.

Due to the inherent uncertainty involved in price movements and potential deviation from historical pricing, Xcel Energy is unable to fully assure that its risk management programs and procedures would be effective to protect against all significant adverse market deviations.

In addition, Xcel Energy cannot fully assure that its controls will be effective against all potential risks, including, without limitation, employee misconduct. If such programs and procedures are not effective, Xcel Energy's results of operations, financial condition or cash flows could be materially impacted.

Failure to attract and retain a qualified workforce could have an adverse effect on operations.

In 2021, the competition for talent has become increasingly intense as a result of the ongoing “great resignation”, and we may experience increased employee turnover due to this tightening labor market. In addition, specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets, which may pose additional difficulty for us as we work to recruit, retain and motivate employees in this climate. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

Our operations use third-party contractors in addition to employees to perform periodic and ongoing work.

We rely on third-party contractors to perform operations, maintenance and construction work. Our contractual arrangements with these contractors typically include performance standards, progress payments, insurance requirements and security for performance. Poor vendor performance or contractor unavailability could impact ongoing operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

Our employees, directors, third-party contractors, or suppliers may violate or be perceived to violate our Codes of Conduct, which could have an adverse effect on our reputation.

We are exposed to risk of employee or third-party contractor fraud or other misconduct. All employees and members of the Board of Directors are subject to comply with our Code of Conduct and are required to participate in annual training. Additionally, suppliers are subject to comply with our supplier Code of Conduct.

Xcel Energy does not tolerate discrimination, violations of our Code of Conduct or other unacceptable behaviors. However, it is not always possible to identify and deter misconduct by employees and other third-parties, which may result in governmental investigations, other actions or lawsuits. If such actions are taken against us we may suffer loss of reputation and such actions could have a material effect on our financial condition, results of operations and cash flows.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota has two nuclear generation plants, PI and Monticello. Risks of nuclear generation include:

- Hazards associated with the use of radioactive material in energy production, including management, handling, storage and disposal.
- Limitations on insurance available to cover losses that may arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor.
- Technological and financial uncertainties related to the costs of decommissioning nuclear plants may cause our funding obligations to change.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including the ability to impose fines and/or shut down a unit until compliance is achieved. NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the INPO reviews NSP-Minnesota’s nuclear operations. Compliance with the INPO’s recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If a nuclear incident did occur, it could have a material impact on our results of operations, financial condition or cash flows. Furthermore, non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased industry regulation, which may increase NSP-Minnesota’s compliance costs.

Financial Risks

Our profitability depends on the ability of our utility subsidiaries to recover their costs and changes in regulation may impair the ability of our utility subsidiaries to recover costs from their customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services and earning a return on capital investment. Our rates are generally regulated and are based on an analysis of the utility’s costs incurred in a test year. The utility subsidiaries are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital.

There can also be no assurance that our regulatory commissions will judge all the costs of our utility subsidiaries to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery.

Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair the ability of our utility subsidiaries to recover costs historically collected from customers, or these subsidiaries could exceed caps on capital costs required by commissions and result in less than full recovery.

Changes in the long-term cost-effectiveness or to the operating conditions of our assets may result in early retirements of utility facilities. While regulation typically provides cost recovery relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

Higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on common stock.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that our current credit ratings or our subsidiaries' ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, use of historic test years, elimination of riders or interim rates, increasing depreciation lives, lower returns on equity, changes to equity ratios and impacts of tax policy may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any credit ratings downgrade could lead to higher borrowing costs or lower proceeds from equity issuances. It could also impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require posting of collateral or settlement if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates or lower proceeds from equity issuances. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

The performance of capital markets impacts the value of assets held in trusts to satisfy future obligations to decommission NSP-Minnesota's nuclear plants and satisfy our defined benefit pension and postretirement benefit plan obligations. These assets are subject to market fluctuations and yield uncertain returns, which may fall below expected returns. A decline in the market value of these assets may increase funding requirements. Additionally, the fair value of the debt securities held in the nuclear decommissioning and/or pension trusts may be impacted by changes in interest rates.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the economy and unemployment rates.

Credit risk also includes the risk that counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

Xcel Energy may have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, (e.g., California Independent System Operator, SPP, PJM Interconnection, LLC, MISO and Electric Reliability Council of Texas), in which any credit losses are socialized to all market participants.

We have additional indirect credit exposure to financial institutions from letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements of these plans. Estimates and assumptions may change. In addition, the Pension Protection Act sets the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year, due to high numbers of retirements or employees leaving, would trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs.

Increasing costs associated with health care plans may adversely affect our results of operations.

Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Health care legislation could also significantly impact our benefit programs and costs.

We must rely on cash from our subsidiaries to make dividend payments.

Investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and ability to service our debt and pay dividends depends upon the operating cash flows of our subsidiaries and their payment of dividends.

Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for dividends on our common stock. In addition, each subsidiary's ability to pay dividends depends on statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets.

If the utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected. Our utility subsidiaries are regulated by state utility commissions, which possess broad powers to ensure that the needs of the utility customers are met. We may be negatively impacted by the actions of state commissions that limit the payment of dividends by our utility subsidiaries.

Federal tax law may significantly impact our business.

Our utility subsidiaries collect estimated federal, state and local tax payments through their regulated rates. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value/availability of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. If tax rates are increased, there could be timing delays before regulated rates provide for recovery of such tax increases in revenues. In addition, certain IRS tax policies, such as tax normalization, may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Xcel Energy's operations are affected by local, national and worldwide economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills, which could lead to additional bad debt expense.

Our utility subsidiaries face competitive factors, which could have an adverse impact on our financial condition, results of operations and cash flows. Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may inhibit our ability to acquire sufficient supplies. We operate in a capital-intensive industry and federal trade policy could significantly impact the cost of materials we use. There may be delays before these additional material costs can be recovered in rates.

We face risks related to health epidemics and other outbreaks, which may have a material effect on our financial condition, results of operations and cash flows.

The global outbreak of COVID-19 continues to impact countries, communities, supply chains and markets. A high degree of uncertainty continues to exist regarding the pandemic; the duration and magnitude of business restrictions (domestically and globally); the potential shortages of employees and third-party contractors due to quarantine policies, vaccination requirements or government restrictions; re-shutdowns, if any, and the level and pace of economic recovery.

Xcel Energy has experienced and may continue to experience sales volatility and shifts between residential and C&I sales as a result of COVID-19. Xcel Energy has a decoupling mechanism in Colorado for residential and non-demand small C&I electric customer classes. In Minnesota, Xcel Energy has historically had a sales true-up mechanism for all electric customer classes which has ended in 2021. We are requesting implementation of a new sales true-up mechanism for 2022 - 2024. These mechanisms mitigate the impact of changes to sales levels as compared to a baseline.

Although the financial impact of the pandemic on our financial results has largely been mitigated, we cannot ultimately predict whether it will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact of the virus on the health of our employees, our supply chain or our ability to recover higher costs associated with managing through the pandemic. The impact of COVID-19 may exacerbate other risks discussed herein, which could have a material effect on us. The situation is evolving and additional impacts may arise.

Operations could be impacted by war, terrorism or other events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows.

The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility.

We also face the risks of possible loss of business due to significant events such as severe storms, severe temperature extremes, wildfires (particularly in Colorado), widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a workforce disruption.

In addition, major catastrophic events throughout the world may disrupt our business. Xcel Energy participates in a global supply chain, which includes materials and components that are globally sourced. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to reliably serve our customers.

A major disruption could result in a significant decrease in revenues and additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

Xcel Energy participates in GridEx, which is the largest grid security exercise in North America. These efforts, led by the NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

A cyber incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals.

Xcel Energy's generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error.

The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. During the normal course of business, we have experienced and expect to continue to experience attempts to compromise our information technology and control systems, network infrastructure and other assets. To date, no cybersecurity incident or attack has had a material impact on our business or results of operation.

Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

Xcel Energy's generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers' operations, could also negatively impact our business.

Our supply chain for procurement of digital equipment and services may expose software or hardware to these risks and could result in a breach or significant costs of remediation. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. Cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including asset failure or unauthorized access to assets or information.

A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations or cash flows.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change may create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. International agreements could additionally lead to future federal or state regulations.

In 2015, the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2º Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5º Celsius.

In April 2021, ahead of the United Nations Climate Change Conference in Glasgow, the Biden Administration committed the U.S. to a Nationally Determined Contribution of 50-52% net GHG emissions reduction economy-wide from 2005 levels. This commitment and other agreements made in Glasgow could result in future additional GHG reductions in the United States. In addition, the Biden Administration has announced plans to implement new climate change programs, including potential regulation of GHG emissions targeting the utility industry.

Many states and localities continue to pursue their own climate policies. The steps Xcel Energy has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation or retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties.

In the event of serious incidents, these agencies may pursue penalties. In addition, certain states have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

The continued use of natural gas for both power generation and gas distribution have increasingly become a public policy advocacy target. These efforts may result in a limitation of natural gas as an energy source for both power generation and heating, which could impact our ability to reliably and affordably serve our customers.

In recent years, there have been various local and state agency proposals within and outside our service territories that would attempt to restrict the use and availability of natural gas. If such policies were to prevail, we may be forced to make new resource investment decisions which could potentially result in stranded costs if we are not able to fully recover costs and investments and impact the overall reliability of our service.

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate sites where our past activities, or the activities of other parties, caused environmental contamination.

Changes in environmental policies and regulations or regulatory decisions may result in early retirements of our generation facilities. While regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or O&M costs incurred to comply with the requirements.

In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events. Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

Climate change may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods.

To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We have committed to a number of long-term climate change goals, which in part are dependent on future technologies not currently in existence. Given the long-term nature of these goals, there is an inherent uncertainty due to internal and external factors regarding our ability to achieve our stated climate change goals. To the extent climate change goals are not met, this could negatively impact our reputation and potentially result in financial risk.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities.

While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows.

Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of power plants and increase the cost for energy. Adverse events may result in increased insurance costs and/or decreased insurance availability. We may not recover all costs related to mitigating these physical and financial risks.

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 2 — PROPERTIES

Virtually all of the utility plant property of the operating companies is subject to the lien of their respective first mortgage bond indentures.

NSP-Minnesota

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]	
Steam:				
A.S. King-Bayport, MN, 1 Unit [f]	Coal	1968	511	
Sherco-Becker, MN [e]				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	517	(b)
Monticello, MN, 1 Unit	Nuclear	1971	617	
PI-Welch, MN				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Various locations, 4 Units	Wood/Refuse	Various	36	(c)
Combustion Turbine:				
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327	
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2018	494	
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	447	
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530	
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	252	
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454	
Various locations, 7 Units	Natural Gas	Various	10	
Wind:				
Blazing Star 1-Lincoln County, MN, 100 Units	Wind	2020	200	(d)
Blazing Star 2-Lincoln County, MN, 100 Units	Wind	2021	200	(d)
Border-Rolette County, ND, 75 Units	Wind	2015	148	(d)
Community Wind North-Lincoln County, MN, 12 Units	Wind	2020	26	(d)
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190	(d)
Crowned Ridge 2-Grant County, SD, 88 Units	Wind	2020	192	(d)
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150	(d)
Freeborn-Freeborn County, MN, 100 Units	Wind	2021	200	(d)
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	99	(d)
Jeffers-Cottonwood County, MN, 20 Units	Wind	2020	43	(d)
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99	(d)
Mower-Mower County, MN, 43 Units	Wind	2021	91	(d)
Nobles-Nobles County, MN, 134 Units	Wind	2010	197	(d)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196	(d)
		Total	8,628	

(a) Summer 2021 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(e) A.S. King is expected to be retired early in 2028.
(f) Sherco Unit 1, 2, and 3 are expected to be retired early in 2026, 2023 and 2030, respectively.

NSP-Wisconsin

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]	
Steam:				
Bay Front-Ashland, WI, 2 Units	Wood/Natural Gas	1948 - 1956	41	
French Island-La Crosse, WI, 2 Units	Wood/Refuse	1940 - 1948	16	(b)
Combustion Turbine:				
French Island-La Crosse, WI, 2 Units	Oil	1974	122	
Wheaton-Eau Claire, WI, 5 Units	Natural Gas/ Oil	1973	234	
Hydro:				
Various locations, 63 Units	Hydro	Various	135	
		Total	548	

(a) Summer 2021 net dependable capacity.
(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]	
Steam:				
Comanche-Pueblo, CO [b]				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(c)
Craig-Craig, CO, 2 Units [d]	Coal	1979 - 1980	82	(e)
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233	(f)
Pawnee-Brush, CO, 1 Unit	Coal	1981	505	
Cherokee-Denver, CO, 1 Unit	Natural Gas	1968	310	
Combustion Turbine:				
Blue Spruce-Aurora, CO, 2 Units	Natural Gas	2003	264	
Cherokee-Denver, CO, 3 Units	Natural Gas	2015	576	
Fort St. Vrain-Platteville, CO, 6 Units	Natural Gas	1972 - 2009	973	
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580	
Various locations, 8 Units	Natural Gas	Various	251	
Hydro:				
Cabin Creek-Georgetown, CO				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 8 Units	Hydro	Various	25	
Wind:				
Rush Creek, CO, 300 units	Wind	2018	582	(g)
Cheyenne Ridge, CO, 229 units	Wind	2020	477	(g)
		Total	6,228	

(a) Summer 2021 net dependable capacity.
(b) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in 2022 and 2025, respectively.
(c) Based on PSCo's ownership of 67%.
(d) Craig Unit 1 and 2 are expected to be retired early in 2025 and 2028, respectively.
(e) Based on PSCo's ownership of 10%.
(f) Based on PSCo's ownership of 76% of Unit 1 and 37% of Unit 2.
(g) Values disclosed are the generation levels at the point-of-interconnection. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

SPS

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	225
Harrington-Amarillo, TX, 3 Units [b]	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	298
Tolk-Muleshoe, TX, 2 Units [d]	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	207
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units	Wind	2019	477 [c]
Sagamore-Dora, NM, 240 Units	Wind	2020	507 [c]
		Total	5,249

(a) Summer 2021 net dependable capacity.
(b) Harrington is expected to be converted to natural gas by the end of 2024.
(c) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(d) Tolk Unit 1 and 2 are proposed to be retired in 2034.

Electric utility overhead and underground transmission and distribution lines at Dec. 31, 2021:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Transmission				
500 KV	2,915	—	—	—
345 KV	13,570	2,943	4,978	11,688
230 KV	2,300	—	12,141	9,763
161 KV	640	1,778	—	—
138 KV	—	—	92	—
115 KV	8,086	1,818	5,075	14,880
Less than 115 KV	6,644	5,870	1,830	4,423
Total Transmission	34,155	12,409	24,116	40,754
Distribution				
Less than 115 KV	81,406	27,701	78,712	22,651
Total	**115,561**	**40,110**	**102,828**	**63,405**

Electric utility transmission and distribution substations at Dec. 31, 2021:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	354	204	237	458

Natural gas utility mains at Dec. 31, 2021:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	85	3	2,174	20	11
Distribution	10,741	2,526	23,243	—	—

ITEM 3 — LEGAL PROCEEDINGS

Xcel Energy is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's consolidated financial statements. Legal fees are generally expensed as incurred.

See Note 12 to the consolidated financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5 — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

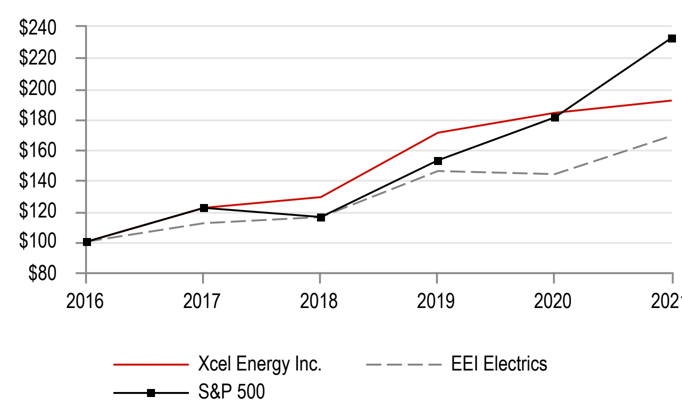
Stock Data

Xcel Energy Inc.'s common stock is listed on the Nasdaq Global Select Market (Nasdaq). The trading symbol is XEL. The number of common stockholders of record as of Feb. 17, 2022 was approximately 49,137.

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the S&P 500 Composite Stock Price Index over the last five years.

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 39 companies at year-end and is a broad measure of industry performance.

Comparison of Five Year Cumulative Total Return*



* $100 invested on Dec. 31, 2016 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2021, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6 — [RESERVED]

ITEM 7 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing ROE, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Ongoing ROE

Ongoing ROE is calculated by dividing the net income or loss of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results.

Earnings Adjusted for Certain Items (Ongoing Earnings and Ongoing Diluted EPS)

GAAP diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method. Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Ongoing diluted EPS is calculated by dividing the net income or loss of each subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing diluted EPS for each subsidiary is calculated by dividing the net income or loss of such subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period.

We use these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the years ended Dec. 31, 2021 and 2020, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

	2021	2020
Diluted Earnings (Loss) Per Share	GAAP and Ongoing Diluted EPS	GAAP and Ongoing Diluted EPS
PSCo	$ 1.22	$ 1.11
NSP-Minnesota	1.12	1.12
SPS	0.59	0.56
NSP-Wisconsin	0.20	0.20
Earnings from equity method investments — WYCO	0.05	0.05
Regulated utility [(a)]	3.18	3.04
Xcel Energy Inc. and Other	(0.22)	(0.25)
Total [(a)]	$ 2.96	$ 2.79

(a) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating Xcel Energy and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, reporting results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

2021 Comparison with 2020

Xcel Energy — GAAP and ongoing earnings increased $0.17 per share for 2021. The increase was driven by capital investment recovery and other regulatory outcomes, partially offset by increases in depreciation and lower AFUDC. Fluctuations in electric and natural gas revenues associated with changes in fuel and purchased power and/or natural gas sold and transported generally do not significantly impact earnings (changes in revenues are offset by the related variation in costs).

PSCo — Earnings increased $0.11 per share for 2021, driven by capital investment recovery and other regulatory outcomes. Higher revenues were partially offset by increased depreciation, O&M expenses and other taxes (other than income taxes).

NSP-Minnesota — Earnings were flat for 2021 compared to 2020, reflecting capital investment recovery offset by additional depreciation and interest charges.

SPS — Earnings increased $0.03 per share for 2021, largely related to capital investment recovery, other regulatory outcomes and higher sales and demand, partially offset by decreased AFUDC.

NSP-Wisconsin — Earnings were flat for 2021 compared to 2020.

Xcel Energy Inc. and Other — Primarily includes financing costs at the holding company, offset by earnings from EIP investments.

Changes in Diluted EPS

Components significantly contributing to changes in EPS:

2021 vs. 2020		
Diluted Earnings (Loss) Per Share		**Dec. 31**
GAAP and ongoing diluted EPS — 2020	**$**	**2.79**
Components of change — 2021 vs. 2020		
Higher electric revenues, net of electric fuel and purchased power		0.26
Lower ETR [(a)]		0.17
Higher natural gas revenues, net of cost of natural gas sold and transported		0.15
Changes in taxes (other than income taxes)		(0.03)
Lower AFUDC		(0.10)
Higher depreciation and amortization		(0.24)
Other (net)		(0.04)
GAAP and ongoing diluted EPS — 2021	**$**	**2.96**

(a) Includes PTCs and plant regulatory amounts, which are primarily offset as a reduction to electric revenues.

ROE for Xcel Energy and its utility subsidiaries:

	2021	**2020**
ROE	**GAAP and Ongoing ROE**	**GAAP and Ongoing ROE**
NSP-Minnesota	8.45 %	9.20 %
PSCo	8.23	8.06
SPS	9.22	9.54
NSP-Wisconsin	9.92	10.52
Operating Companies	8.58	8.87
Xcel Energy	10.58	10.59

Statement of Income Analysis

The following summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances, the amount of natural gas or electricity historically used per degree of temperature and excludes any incremental related operating expenses that could result due to storm activity or vegetation management requirements. As a result, weather deviations from normal levels can affect Xcel Energy's financial performance. However, sales true-up and decoupling mechanisms in Minnesota and Colorado predominately mitigate the positive and adverse impacts of weather.

Degree-day or THI data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. HDD is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. CDD is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 10, 20 or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates.

Percentage (decrease) increase in normal and actual HDD, CDD and THI:

	2021 vs. Normal	**2020 vs. Normal**	**2021 vs. 2020**
HDD	(6.6)%	(3.1)%	(4.3)%
CDD	12.2	22.2	(9.2)
THI	26.8	6.3	20.7

Weather — Estimated impact of temperature variations on EPS compared with normal weather conditions:

	2021 vs. Normal	**2020 vs. Normal**	**2021 vs. 2020**
Retail electric	$ 0.096	$ 0.090	$ 0.006
Decoupling and sales true-up	(0.066)	(0.041)	(0.025)
Electric total	$ 0.030	$ 0.049	$ (0.019)
Firm natural gas	(0.025)	(0.011)	(0.014)
Total	$ 0.005	$ 0.038	$ (0.033)

Sales — Sales growth (decline) for actual and weather-normalized sales:

	2021 vs. 2020				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Actual					
Electric residential	— %	2.2 %	(4.7)%	0.5 %	0.3 %
Electric C&I	0.4	2.3	2.9	3.6	2.0
Total retail electric sales	0.3	2.2	1.4	2.7	1.4
Firm natural gas sales	(1.1)	(4.0)	N/A	(5.0)	(2.2)

	2021 vs. 2020				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Weather-normalized					
Electric residential	1.5 %	0.3 %	(1.0)%	(0.2)%	0.5 %
Electric C&I	0.4	1.7	3.3	3.3	1.9
Total retail electric sales	0.8	1.2	2.5	2.2	1.4
Firm natural gas sales	1.3	(2.2)	N/A	(4.1)	(0.1)

	2021 vs. 2020 (2020 Leap Year Adjusted)				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Weather-normalized					
Electric residential	1.7 %	0.6 %	(0.7)%	0.1 %	0.8 %
Electric C&I	0.7	1.9	3.6	3.6	2.1
Total retail electric sales	1.1	1.5	2.7	2.5	1.7
Firm natural gas sales	1.8	(1.7)	N/A	(3.6)	0.4

Weather-normalized and leap-year adjusted electric sales growth (decline) — year-to-date

Weather-adjusted sales results for each of our utility subsidiaries in 2021 reflect improving economies as the adverse effects of COVID-19 lessen. The recovery reflects increased sales in the C&I sector as businesses return to a more normal level. Residential sales remain elevated from pre-pandemic levels due to continuance of individuals working from home.

- PSCo — Residential sales rose based on a 1.2% increase in customers, combined with higher use per customer. The growth in C&I sales was due to a 1.2% increase in customers, partially offset by slightly lower use per customer, primarily in the services sector.
- NSP-Minnesota — Residential sales growth reflects a 1.2% increase in customers, partially offset by a lower use per customer. The growth in C&I sales was due to a 0.9% increase in customers and higher use per customer, primarily in the manufacturing, retail and services sectors.
- SPS — Residential sales declined as lower use per customer offset a 0.9% increase in customers. C&I sales increased due to a 0.5% increase in customers and higher use per customer, primarily driven by the oil and gas and professional services sectors.
- NSP-Wisconsin — Residential sales growth was attributable to a 0.8% increase in customer additions, partially offset by slightly lower use per customer. The growth in C&I sales was due to a 1.1% increase in customers, primarily led by increases in the manufacturing, health care and retail trade sectors.

Weather-normalized and leap-year adjusted natural gas sales growth (decline) — year-to-date

- Natural gas sales primarily reflect a 1.2% increase in residential customers and a 0.5% increase in C&I customers, partially offset by a decrease in use per customer.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium. However, these price fluctuations generally have minimal impact on earnings impact due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes.

Electric Revenues, Fuel and Purchased Power and Electric Margin

(Millions of Dollars)	2021	2020
Electric revenues	$ 11,205	$ 9,802
Electric fuel and purchased power	(4,733)	(3,512)
Electric margin	$ 6,472	$ 6,290

Changes in Electric Margin

(Millions of Dollars)	2021 vs. 2020
Non-fuel riders	$ 221
Regulatory rate outcomes (Texas, Wisconsin, Colorado, New Mexico and North Dakota)	114
Proprietary commodity trading, net of sharing [a]	40
Sales and demand [b]	29
PTCs flowed back to customers (offset by lower ETR)	(149)
Texas 2019 rate case surcharge [c]	(70)
Estimated impact of weather (net of decoupling/sales true-up)	(12)
Other (net)	9
Increase in electric margin	$ 182

(a) Includes $27 million of net gains recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri. Additional amounts are primarily related to long-term physical generation contracts, which have increased in value as a result of higher energy prices.

(b) Sales excludes weather impact, net of decoupling/sales true-up, and demand is net of sales true-up.

(c) Impact is due to the Texas rate case outcome, which resulted in a revenue increase that was recognized in the third quarter of 2020 (largely offset by recognition of previously deferred costs).

Natural Gas Margin

Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for the cost of natural gas sold are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas generally have minimal earnings impact due to cost recovery mechanisms.

Natural Gas Revenues, Cost of Natural Gas Sold and Transported and Natural Gas Margin

(Millions of Dollars)	2021	2020
Natural gas revenues	$ 2,132	$ 1,636
Cost of natural gas sold and transported	(1,081)	(689)
Natural gas margin	$ 1,051	$ 947

Changes in Natural Gas Margin

(Millions of Dollars)	2021 vs. 2020
Regulatory rate outcomes (Colorado and North Dakota)	$ 90
Infrastructure and integrity riders	12
Conservation incentive	3
Estimated impact of weather	(10)
Other (net)	9
Increase in natural gas margin	$ 104

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $3 million year-to-date. Increases for distribution, wind farm maintenance and technology costs were offset by a decrease in employee benefits expense (e.g., long term incentives), additional Texas 2021 rate case deferrals and the year-over-year impact of amounts associated with the Texas 2019 rate case surcharge.

Depreciation and Amortization — Depreciation and amortization increased $173 million year-to-date. The increase was primarily driven by several wind farms going into service, normal system expansion and the implementation of new depreciation rates in various states.

Other Income (Expense) — Other income (expense) increased $11 million year-to-date. The change was largely related to gains associated with rabbi trust performance (offset in O&M expenses).

AFUDC, Equity and Debt — AFUDC decreased $58 million year-to-date. The decrease was driven by completion of various wind projects throughout 2020 and 2021.

Interest Charges — Interest charges increased $2 million year-to-date. The increase was largely due to higher debt levels to fund capital investments, partially offset by lower long-term and short-term interest rates.

Earnings from Equity Method Investments — Earnings from equity method investments increased $22 million year-to-date. The year-to-date change was largely attributable to the performance of the EIP funds, which invest in energy technology companies.

Income Taxes — Income tax benefit increased $64 million year-to-date. The change was driven by an increase in wind PTCs due to additional wind facilities going into service. Impact of PTCs was partially offset by an increase in pretax earnings, lower plant regulatory differences and lower non-plant accumulated deferred income tax amortization.

Xcel Energy Inc. and Other Results

Net income and diluted EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

	Contribution (Millions of Dollars)	
	2021	2020
Xcel Energy Inc. financing costs	$ (129)	$ (147)
MEC [(a)]	—	15
Venture Holdings [(b)]	21	4
Xcel Energy Inc. taxes and other results	(12)	(5)
Total Xcel Energy Inc. and other costs	$ (120)	$ (133)

	Contribution (Diluted Earnings (Loss) Per Share)	
	2021	2020
Xcel Energy Inc. financing costs	$ (0.24)	$ (0.28)
MEC [(a)]	—	0.03
Venture Holdings [(b)]	0.04	0.01
Xcel Energy Inc. taxes and other results	(0.02)	(0.01)
Total Xcel Energy Inc. and other costs	$ (0.22)	$ (0.25)

(a) MEC was sold in the third quarter of 2020.

(b) Amounts include gains or losses associated with EIP investments.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

2020 Comparison with 2019

A discussion of changes in Xcel Energy's results of operations, cash flows and liquidity and capital resources from the year ended Dec. 31, 2019 to Dec. 31, 2020 can be found in Part II, "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year 2020, which was filed with the SEC on Feb. 17, 2021. However, such discussion is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Public Utility Regulation

The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and West Gas Interstate. Xcel Energy is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota, South Dakota, Wisconsin, Michigan, Colorado, New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. Our utility subsidiaries request changes in utility rates through commission filings. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact Xcel Energy's results of operations.

See Rate Matters within Note 12 to the consolidated financial statements for further information.

NSP-Minnesota

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
MPUC	Retail rates, services, security issuances, property transfers, mergers, disposition of assets, affiliate transactions, and other aspects of electric and natural gas operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. Certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV in Minnesota. Reviews and approves natural gas supply plans. Pipeline safety compliance.
NDPSC	Retail rates, services and other aspects of electric and natural gas operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota. Pipeline safety compliance.
South Dakota Public Utilities Commission	Retail rates, services and other aspects of electric operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in South Dakota. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce.
MISO	NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and wholesale markets. NSP-Minnesota makes wholesale sales in other RTO markets at market-based rates. NSP-Minnesota and NSP-Wisconsin also make wholesale electric sales at market-based prices to customers outside of their balancing authority as jointly authorized by the FERC.
DOT	Pipeline safety compliance.
Minnesota Office of Pipeline Safety	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
CIP Rider [(a)]	Recovers costs of conservation and DSM programs in Minnesota.
Environmental Improvement Rider	Recovers costs of environmental improvement projects in Minnesota.
Renewable Development Fund	Allocates money collected from customers to support research and development of emerging renewable energy projects and technologies in Minnesota.
RES	Recovers cost of renewable generation in Minnesota.
Renewable Energy Rider	Recovers cost of renewable generation in North Dakota.
State Energy Policy Rider	Recovers costs related to various energy policies approved by the Minnesota legislature.
TCR	Recovers costs for investments in electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation and incremental property taxes in South Dakota.
FCA [(b)]	Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. MISO costs are generally recovered through either the FCA or base rates.
Purchased Gas Adjustment	Provides for prospective monthly rate adjustments for costs of purchased natural gas, transportation and storage service. Includes a true-up process for difference between projected and actual costs.
GUIC Rider	Recovers costs for transmission and distribution pipeline integrity management programs, including funding for pipeline assessments, deferred costs for sewer separation and pipeline integrity management programs in Minnesota.
Sales True-up	In February 2022, NSP-Minnesota filed the 2021 sales true-up compliance report, resulting in a total surcharge of $59 million. An MPUC ruling is anticipated in the second quarter of 2022. In their current rate case, NSP-Minnesota has proposed a sales true-up mechanism for 2022 and beyond that would operate similarly to the 2021 sales true-up. Under the stay-out petition, 2021 NSP-Minnesota jurisdictional earnings was capped at a 9.06% ROE. Any excess earnings are required to be refunded to customers.

(a) Minnesota state law requires NSP-Minnesota to spend 2% of its state electric revenues and 0.5% of its state natural gas revenues on CIP. These costs are recovered through an annual cost-recovery mechanism.

(b) The MPUC changed the FCA process in Minnesota (effective in 2020). Each month, utilities collect amounts equal to baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to baseline costs are tracked and netted over a 12-month period. Utilities issue refunds above the baseline costs and can seek recovery of any overage.

Pending and Recently Concluded Regulatory Proceedings

2022 Minnesota Natural Gas Rate Case — In November 2021, NSP-Minnesota filed a request with the MPUC for an annual natural gas rate increase of $36 million, or 6.6%. The filing is based on a 2022 forecast test year and includes a requested ROE of 10.5%, rate base of $934 million and an equity ratio of 52.50%.

In December 2021, the MPUC approved the requested interim rates of $25 million, subject to refund, beginning on Jan. 1, 2022.

The next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: Aug. 30, 2022.
- Rebuttal testimony: Oct. 4, 2022.
- Public hearing: Nov. 1-4, 2022.
- ALJ Report: Feb. 6, 2023.
- MPUC Order: April 26, 2023.

2022 Minnesota Electric Rate Case — In October 2021, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested ROE of 10.2%, a 52.50% equity ratio and forward test years.

The request is detailed as follows:

(Amounts in Millions, Except Percentages)	2022	2023	2024	Total
Rate request	$ 396	$ 150	$ 131	$ 677
Increase percentage	12.2 %	4.8 %	4.2 %	21.2 %
Rate base	$ 10,931	$ 11,446	$ 11,918	N/A

In addition, NSP-Minnesota requested interim rates, subject to refund, of $288 million to be implemented in January 2022 and an incremental $135 million to be implemented in January 2023. In December 2021, the MPUC approved rates of $247 million to begin on Jan. 1, 2022. The adjusted level reflects exigent circumstances from the COVID-19 pandemic.

The next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: Oct. 3, 2022.
- Rebuttal testimony: Nov. 8, 2022.
- Public hearing: Dec. 13-16, 2022.
- ALJ Report: March 31, 2023.
- MPUC Order: June 30, 2023.

2021 North Dakota Natural Gas Rate Case — In September 2021, NSP-Minnesota filed a request with the NDPSC for a natural gas rate increase of $7 million, or 10.49%. The filing is based on a requested ROE of 10.5%, an equity ratio of 52.54%, a 2022 forecast test year and a rate base of approximately $140 million. Interim rates of $7 million, subject to refund, were implemented on Nov. 1, 2021. An NDPSC decision is expected in early fall 2022.

The next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: March 1, 2022
- Rebuttal testimony: April 1, 2022
- Hearings: June 1-3, 2022

2020 North Dakota Electric Rate Case — In November 2020, NSP-Minnesota filed a rate case with the NDPSC seeking a rate increase of $19 million based on a ROE of 10.2%, an equity ratio of 52.5% and rate base of $677 million.

In August 2021, the NDPSC approved a settlement between NSP-Minnesota and various parties, which includes the following, effective Jan. 1, 2021:

- Base revenue increase of $7 million.
- ROE of 9.5%.
- Equity ratio of 52.5%.
- Deferral of advanced grid intelligence and security initiative capital and O&M expenses.
- An earnings cap mechanism, which would return to customers 100% of earnings equal to or in excess of 9.75% ROE, effective until the next rate case.

Minnesota Relief and Recovery — In 2020, the MPUC opened a docket and invited utilities in the state to submit potential projects that would create jobs and help jump start the economy to offset the impacts of COVID-19.

The status of the various proposals is listed below:

- In January 2021, the MPUC approved NSP-Minnesota's request for the repowering of 651 MW of owned wind projects and 20 MW of wind projects under PPAs. These projects are estimated to save customers approximately $160 million over the next 25 years.
- In April 2021, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an incremental investment of approximately $575 million. An MPUC decision is expected by the third quarter of 2022.
- In June 2021, the MPUC approved NSP-Minnesota's proposal to acquire a repowered wind farm from ALLETE, Inc.
- The MPUC is also considering NSP-Minnesota's revised proposal to provide $40 million of incremental electric vehicle rebates.

Minnesota Resource Plan — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034.

On Feb. 8, 2022, the MPUC approved the following:

- 10-year extension for the Monticello nuclear facility.
- Retirement of the A.S. King plant in 2028 and Sherco 3 in 2030.
- NSP-Minnesota ownership of Sherco and A.S. King gen-tie lines plus additional renewable resources on the lines up to its current interconnection rights (2,000 MW for Sherco and 600 MW for A.S. King).
- The need for 2,150 MW of new wind and 2,500 MW of new solar by 2032, as well as additional renewable generation of 1,100 MW beyond 2032.
- Recognition of the need for 800 MW of additional firm dispatchable resources between 2027 and 2029. The dispatchable generation will need to be approved through a CON process.

The next Minnesota resource plan is due on Feb. 1, 2024.

2022 RES Electric Rider — In November 2021, NSP-Minnesota filed the RES Rider. The requested amount of $264 million includes a true-up (2020 and 2021 riders) of $154 million and the 2022 requested amount of $110 million. The filing included a ROE of 9.06%. An MPUC decision is pending.

2021 RES Electric Rider — In November 2020, NSP-Minnesota filed the RES Rider. The requested amount of $189 million includes a true-up (2019 and 2020 riders) of $96 million and the 2021 requested amount of $93 million. The filing included a ROE of 9.06%. An MPUC decision is pending.

2022 GUIC Natural Gas Rider — In October 2021, NSP-Minnesota filed the GUIC Rider for an amount of $27 million based on a ROE of 9.04%. An MPUC decision is pending.

2021 GUIC Natural Gas Rider — In October 2020, NSP-Minnesota filed the GUIC Rider for an amount of $27 million based on a ROE of 9.04%. An MPUC decision is pending.

2022 TCR Electric Rider — In November 2021, NSP-Minnesota filed the TCR Rider for an amount of $105 million based on a ROE of 9.06%. An MPUC decision is pending.

2020 TCR Electric Rider — In November 2019, NSP-Minnesota filed the TCR Rider for an amount of $82 million based on a ROE of 9.06%, which was approved by the MPUC in December 2021.

FERC NOPR on ROE Incentive Adders — In April 2021, the FERC issued a NOPR proposing to limit collection of ROE incentive adders for RTO membership to the first three years after an entity begins participation in an RTO. If adopted as a final rule, NSP-Minnesota (as well as NSP-Wisconsin and SPS) would prospectively discontinue charging their current 50 basis point ROE incentive adders. Amounts related to a discontinuance of the adder would ultimately be offset by an increase in retail rates, subject to future rate cases.

Purchased Power Arrangements and Transmission Service Provider

NSP-Minnesota expects to use power plants, power purchases, CIP/DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a capacity and an energy charge.

NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Nuclear Power Operations

Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes, which are covered by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment contaminated through use.

NRC Regulation — The NRC regulates nuclear operations. Costs of complying with NRC requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs and expects to recover future compliance costs.

Low-Level Waste Disposal — Low level waste disposal from Monticello and PI is disposed at the Clive facility located in Utah and the Waste Control Specialists facility in Texas. NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives if off-site low-level waste disposal facilities become unavailable.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. Currently, there are no definitive plans for a permanent federal storage facility site.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

Monticello CON — In September 2021, NSP-Minnesota filed an application for a CON for additional spent fuel storage (existing independent spent fuel storage installation) at the Monticello Nuclear Power Generating Plant. The CON requests sufficient additional spent fuel storage at the existing independent spent fuel storage installation to allow continued operation of the Monticello Plant until 2040. The filing passed completeness review and has been referred to an ALJ. A decision is expected in late 2023.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and to hedge sales and purchases.

NSP-Minnesota also engages in trading activity unrelated to hedging. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

NSP-Wisconsin

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PSCW	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. The PSCW has a biennial base rate filing requirement. By June of each odd numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January. Pipeline safety compliance.
MPSC	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce.
MISO	NSP-Wisconsin is a transmission owning member of the MISO RTO that operates within the MISO RTO and wholesale energy market. NSP-Wisconsin and NSP-Minnesota are jointly authorized by the FERC to make wholesale electric sales at market-based prices.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
Annual Fuel Cost Plan	NSP-Wisconsin does not have an automatic electric fuel adjustment clause. Under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW. Once the PSCW approves the plan, utilities defer the amount of any fuel cost under-recovery or over-recovery in excess of a 2% annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW. Rate recovery of deferred fuel cost is subject to an earnings test based on the most recently authorized ROE. Under-collections that exceed the 2% annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.
Power Supply Cost Recovery Factors	NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-recoveries are refunded and any under-recoveries are collected from customers.
Wisconsin Energy Efficiency Program	The primary energy efficiency program is funded by the utilities, but operated by independent contractors subject to oversight by the PSCW and utilities. NSP-Wisconsin recovers these costs from customers.
Purchased Gas Adjustment	A retail cost-recovery mechanism to recover the actual cost of natural gas, transportation, and storage services.
Natural Gas Cost-Recovery Factor (MI)	NSP-Wisconsin's natural gas rates for Michigan customers include a natural gas cost-recovery factor, based on 12-month projections and trued-up to actual amounts on an annual basis.

Pending and Recently Concluded Regulatory Proceedings

Wisconsin Electric and Natural Gas Settlement — In December 2021, the PSCW approved a rate case settlement agreement and 2022 fuel cost plan without modification. New rates and tariffs were effective Jan. 1, 2022. Key elements of the settlement:

- An increase in electric rates of $35 million (4.9%) for 2022 and an incremental $18 million increase (2.5%) for 2023.
- An increase in natural gas rates of $10 million (8.4%) for 2022 and an incremental $3 million (2.3%) for 2023.
- ROE of 9.80% for 2022 and 10.00% for 2023.
- Equity ratio of 52.5% for both 2022 and 2023.
- Returning $9 million in various net regulatory liabilities to offset customer impacts in 2023.
- Deferring certain pension and other post-employment benefit expense in 2021 through 2023.
- Incorporating an earnings sharing mechanism for 2022 and 2023.

Michigan Electric Rate Case — In January 2022, NSP-Wisconsin reached an electric rate case settlement in principle with the MPSC staff and others. The settlement grants NSP-Wisconsin an electric revenue increase of $1.6 million in 2022, based on a ROE of 9.7% and an equity ratio of 52.5%. The MPSC is expected to rule on the settlement in the first quarter of 2022.

Purchased Power and Transmission Services

The NSP System expects to use power plants, power purchases, conservation and DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — Through the Interchange Agreement, NSP-Wisconsin receives power purchased by NSP-Minnesota from other utilities and independent power producers. Long-term purchased power contracts for dispatchable resources typically require a capacity charge and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates.

PSCo

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information on Regulatory Authority
CPUC	Retail rates, accounts, services, issuance of securities and other aspects of electric, natural gas and steam operations. Pipeline safety compliance.
FERC	Wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. Wholesale electric sales at cost-based prices to customers inside PSCo's balancing authority area and at market-based prices to customers outside PSCo's balancing authority area. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.
RTO	PSCo is not presently a member of an RTO and does not operate within an RTO energy market. However, PSCo does make certain sales to other RTO's, including SPP and participates in a joint dispatch agreement with neighboring utilities.
DOT	Pipeline safety compliance.
SPP Western Energy Imbalance Service Market	Balances generation and load regionally and in real time for participants in the Western Interconnection

Recovery Mechanisms

Mechanism	Additional Information
ECA	Recovers fuel and purchased energy costs. Short-term sales margins are shared with customers. The ECA is revised quarterly.
Purchased Capacity Cost Adjustment	Recovers purchased capacity payments.
Steam Cost Adjustment	Recovers fuel costs to operate the steam system. The Steam Cost Adjustment rate is revised quarterly.
DSM Cost Adjustment	Recovers electric and gas DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
RES Adjustment	Recovers the incremental costs of compliance with the RES with a maximum of 1% of the customer's bill.
Colorado Energy Plan Adjustment	Recovers the early retirement costs of Comanche units 1 and 2 to a maximum of 1% of the customer's bill.
Wind Cost Adjustment	Recovers costs for customers who choose renewable resources.
Transmission Cost Adjustment	Recovers costs for transmission investment between rate cases.
Clean Air Clean Jobs Act	Recovers costs associated with the Clean Air Clean Jobs Act.
FCA	PSCo recovers fuel and purchased energy costs from wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay production costs through a forecasted formula rate subject to true-up.
GCA	Recovers costs of purchased natural gas and transportation and is revised quarterly to allow for changes in natural gas rates.
PSIA	Recovers costs for transmission and distribution pipeline integrity management programs.
Decoupling	Mechanism to true-up revenue to a baseline amount for residential (excluding lighting and demand) and metered non-demand small C&I classes.
Transportation Electrification Plan	Recovers costs associated with the investment in and adoption of transportation electrification infrastructure.

Pending and Recently Concluded Regulatory Proceedings

Colorado Natural Gas Rate Case — In January 2022, PSCo filed a request with the CPUC seeking a net increase to retail natural gas rates of $107 million. The total change to base rates is $215 million, reflecting the transfer of $108 million previously recovered from customers through the PSIA rider, which was closed to new investments at the end of 2021. The request is based on a 10.25% ROE, an equity ratio of 55.66% and a 2022 current test year. PSCo has requested a proposed effective date of Nov. 1, 2022.

Additionally, PSCo's request includes step revenue increases of $40 million in 2023 (effective Nov. 1, 2023) and $41 million in 2024 (effective Nov. 1, 2024) related to continued capital investment. Under this proposal, PSCo would not request another base rate change prior to Nov. 1, 2025. An informational historical test year, including a 10.75% ROE, was also filed as required by the CPUC.

Revenue Request (millions of dollars)		2022
Changes since 2020 rate case:		
Plant related investments [(a)]	$	210
Operations and maintenance, amortization and other expenses		11
Property tax expense		11
Sales growth		(17)
Net increase to revenue		**215**
Previously authorized costs:		
Transfer of costs previously recovered through the PSIA rider		(108)
Total base revenue request	**$**	**107**
Projected 2022 year-end rate base (billions of dollars)	**$**	**3.6**

(a) Includes approximately $28 million as a result of the increase in ROE from 9.2% to 10.25%.

Colorado Electric Rate Request — In July 2021, PSCo filed a request with the CPUC seeking a net electric rate increase of $343 million (or 12.4%). The total request reflects a $470 million increase, which includes $127 million of previously authorized costs currently recovered through various rider mechanisms. The request is based on a 10.0% ROE, an equity ratio of 55.64%, a 2022 forecast test year, a rate base of $10.3 billion and impacts of a new depreciation study.

In January 2022, PSCo reached an unopposed comprehensive settlement. The CPUC is expected to rule on the settlement in March 2022 with final rates expected to be effective in April 2022. Key settlement terms include:

- A net electric rate increase of $177 million. The total change in base rates is $299 million, which includes $122 million of revenue previously collected through various rider mechanisms.
- A ROE of 9.3% and an equity ratio of 55.69%.
- A current 2021 test year (average rate base) with the transfer of Cheyenne Ridge, Wildfire Mitigation Plan and Advanced Grid Intelligence and Security investments at year-end rate base.
- Approval of all of PSCo's proposed depreciation adjustments.
- Continuation of the property tax, qualified pension, and non-qualified pension trackers.
- Continuation of Advanced Grid Intelligence and Security deferral including interest equivalent to PSCo's weighted average cost of capital once the balance exceeds $50 million.
- Continuation of the Wildfire Mitigation Plan deferral, with a debt return.

*PSIA Rider Extensio*n — In October 2021, the CPUC approved a settlement agreement to allow the rider to end on Dec. 31, 2021, transfer the investments recovered under the rider to base rates Jan. 1, 2022, and defer $9 million of depreciation expense and return on $143 million in project costs in 2022.

Pathway Transmission Expansion Settlement — In November 2021, PSCo filed a non-unanimous settlement agreement with Staff and several other parties regarding its CPCN request for the Pathway Transmission project.

Key settlement terms include:

- The parties agreed that PSCo met the burden of proof demonstrating that the project was needed to facilitate the renewables in the Integrated Resource Plan and is in the public interest.
- Agreed to a cost estimate of $1.7 billion and recovery through the transmission rider.
- The Pathway project will also include a Performance Incentive Mechanism such that applicable costs in a given year above or below a 5% dead band would allow for a ROE penalty or adder.
- Parties agreed to conditional CPCN approval for 345 kV extension project subject to the project being included in the final approved Integrated Resource Plan with a cost estimate of $247 million.

The settlement agreement is currently being deliberated by the CPUC.

Resource Plan Settlement — In November 2021, PSCo and intervenors filed a partial settlement of the resource plan, which will result in an expected 87% carbon reduction and an 80% renewable mix by 2030. A CPUC decision is expected in the first quarter of 2022. Key settlement terms include:

- Early retirement of Hayden: Unit 2 in 2027 (was 2036); and Unit 1 in 2028 (was 2030).
- Conversion of Pawnee to burn natural gas by 2026.
- Early retirement of Comanche 3 in 2034 with reduced operations beginning in 2025.
- Addition of ~2,300 MW of wind.
- Addition of ~1,600 MW of utility-scale solar.
- Addition of 400 MW of storage.
- Addition of 1,300 MW of flexible, dispatchable generation.
- Addition of ~1,200 MW of distributed solar resources through our renewable energy programs.

Partial Settlement — In October 2021, PSCo filed a comprehensive settlement with the CPUC Staff and the COEO, which proposed to address four outstanding regulatory items, including recovery of fuel costs related to Winter Storm Uri, disputed revenue associated with the 2020 electric decoupling pilot program year, replacement power costs associated with an extended outage at Comanche Unit 3 during 2020 and deferred customer bad debt balances associated with COVID-19. The Utility Consumer Advocate has not signed the settlement. A hearing and a CPUC decision on the settlement is expected in the first quarter of 2022.

Key terms of the proposed settlement:

- PSCo would fully recover Winter Storm Uri deferred net natural gas, fuel and purchased energy costs of $263 million (electric utility) and $287 million (natural gas utility) over a 24-month and 30-month period, respectively, with no carrying charges through a rider mechanism. Recovery would commence Jan. 1, 2022 for electric costs and April 1, 2022 for natural gas costs.
- PSCo will refund electric customers $41 million (previously deferred) related to the 2020 electric decoupling pilot program.
- PSCo agreed to forego recovery of $14 million for replacement power costs due to an extended outage at Comanche Unit 3 during 2020 (approved by the CPUC in February 2022 as part of the 2020 ECA settlement agreement).
- PSCo also agreed to not seek recovery of COVID-19 related bad debt expense, previously deferred as a regulatory asset, and recorded an additional $11 million of incremental bad debt expense for the period ended Dec. 31, 2021.

Decoupling Filing — PSCo's 2019 Electric Rate Case included a decoupling program, effective April 1, 2020 through Dec. 31, 2023. The program applies to Residential and metered small C&I customers who do not pay a demand charge. The program includes a refund and surcharge cap not to exceed 3% of forecasted base rate revenue for a specified period.

In April 2021, PSCo made its annual filing for 2020, and the revised tariff went into effect by operation of law on June 1, 2021. In the annual filing review, the CPUC indicated they may pursue reopening the case in order to revisit the cap. As of Dec. 31, 2021, PSCo has recognized a refund for Residential customers and a surcharge for C&I customers based on 2020 and 2021 results.

In October 2021, a settlement was reached on Winter Storm Uri costs and also addressed certain components of decoupling. See Partial Settlement disclosure above for further discussion.

Comanche Unit 3 — PSCo is part owner and operator of Comanche Unit 3, a 750 MW, coal-fueled electric generating unit. In January 2020, the unit experienced a turbine failure causing the unit to be taken offline for repairs, which were completed in June 2020. During start-up, the unit experienced a loss of turbine oil, which damaged the unit. Comanche Unit 3 recommenced operations in January 2021. Replacement and repair of damaged systems in excess of a $2 million deductible are expected to be recovered through insurance policies. PSCo incurred replacement power costs of approximately $16 million during the outage.

In October 2020, the CPUC initiated a review of Comanche Unit 3’s performance. In March 2021, the CPUC Staff issued a report, which noted higher-than average outages and included criticisms of PSCo’s operations of Comanche Unit 3 over the last ten years. The report recommended thorough explanation of the future of Comanche Unit 3 operations in the next resource plan, performance standards for all company-owned generation and a review of outage and repair costs in upcoming ECA proceedings.

In October 2021, a comprehensive settlement was reached, which addressed treatment of 2020 Comanche Unit 3 replacement power costs. See Partial Settlement disclosure above for further discussion.

2019 Electric Rate Case Appeal — In August 2020, PSCo filed an appeal with the Denver District Court seeking a review of CPUC decisions on gains and losses on sales of assets, oil and gas royalty revenues, Board of Directors equity compensation and a true-up surcharge to collect the difference between rates from February through August 2020 based on the CPUC's decision on the Company's Application for Reconsideration, Rehearing or Reargument and rates that were actually in place. In January 2022, the Denver District Court issued its decision that the CPUC's approach to gains and losses on certain sales of assets was legally erroneous and confiscatory to PSCo and set aside and remanded the issue for further consideration. The District Court affirmed the CPUC with respect to the remaining decisions.

GCA NOPR — In June 2021, the CPUC issued a NOPR addressing the recovery of costs through the GCA. The proposed rule would establish an annual forecast of GCA costs for each utility and allow each utility to recover only 90%-95% of any costs in excess of the forecasted amount. The proposed rule would allow utilities to earn an incentive equal to an undefined portion of any savings relative to forecasted costs. Comments were filed and requested that the CPUC delay the rule making process until after the 2021 - 2022 heating season; in part because utilities have already proceeded with purchasing gas for the upcoming heating season in accordance with prior CPUC decisions. The CPUC has reopened the GCA NOPR matter and the parties will submit follow-up comments during the first quarter of 2022.

Purchased Power and Transmission Service Providers

PSCo expects to meet its system capacity requirements through electric generating stations, power purchases, new generation facilities, DSM options and expansion of generation plants.

Purchased Power — PSCo purchases power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require capacity and energy charges. It also contracts to purchase power for both wind and solar resources. PSCo makes short-term purchases to meet system load and energy requirements, replace owned generation, meet operating reserve obligations, or obtain energy at a lower cost.

Energy Markets — PSCo plans to join the SPP Western Energy Imbalance Service Market in April 2023. This market is an incremental step in the participation in the organized wholesale market. Energy imbalance markets allow participants to buy and sell power close to the time electricity is consumed and gives system operators real-time visibility across neighboring grids. The result improves balancing supply and demand at a lower cost.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver energy to its customers.

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to hedging. Sharing of any margin is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

SPS

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PUCT	Retail electric operations, rates, services, construction of transmission or generation and other aspects of SPS' electric operations. The municipalities in which SPS operates in Texas have original jurisdiction over rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.
NMPRC	Retail electric operations, retail rates and services and the construction of transmission or generation.
FERC	Wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce.
SPP RTO and SPP Integrated and Wholesale Markets	SPS is a transmission owning member of the SPP RTO and operates within the SPP RTO and SPP integrated and wholesale markets. SPS is authorized to make wholesale electric sales at market-based prices.

Recovery Mechanisms

Mechanism	Additional Information
Distribution Cost Recovery Factor	Recovers distribution costs not included in rates in Texas.
Energy Efficiency Cost Recovery Factor	Recovers costs for energy efficiency programs in Texas.
Energy Efficiency Rider	Recovers costs for energy efficiency programs in New Mexico.
Fuel and Purchased Power Cost Adjustment Clause	Adjusts monthly to recover actual fuel and purchased power costs in New Mexico.
Power Cost Recovery Factor	Allows recovery of purchased power costs not included in Texas rates.
Renewable Portfolio Standards	Recovers deferred costs for renewable energy programs in New Mexico.
TCR Factor	Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in Texas base rates.
Fixed Fuel and Purchased Recovery Factor	Provides for the over- or under-recovery of energy expenses in Texas. Regulations require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis if this condition is expected to continue.
Wholesale Fuel and Purchased Energy Cost Adjustment	SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Pending and Recently Concluded Regulatory Proceedings

2021 New Mexico Electric Rate Case — In January 2021, SPS filed an electric rate case with the NMPRC with a current requested base rate increase of approximately $84 million.

In June 2021, SPS and various parties filed an uncontested stipulation with the NMPRC, which reflected a $62 million rate increase, a change in the depreciation life of the Tolk coal plant to 2032, an equity ratio of 54.72% and ROE of 9.35% for reconciliation statements and determining the revenue requirements for the Sagamore and Hale wind projects. In December 2021, the Hearing Examiner issued a recommendation that the NMPRC approve the rate case settlement agreement without modification.

On Feb. 2, 2022, the NMPRC voted 3-2 to reject the uncontested stipulation as filed. The NMPRC then approved a modified settlement, which would maintain the proposed revenue requirement increase of $62 million, but would adjust the class cost allocation such that all rate classes would have a uniform increase of 4.89%. The NMPRC required the parties to either file their acceptance or opposition to the modified settlement.

On Feb. 9, 2022, the signatories informed the NMPRC they did not unanimously support the modifications. Accordingly, the Hearing Examiner will issue a procedural order for further proceedings on SPS' originally filed application.

On Feb. 10, 2022, SPS filed a motion requesting the NMPRC either approve the original settlement or approve the modified settlement.

On Feb. 16, 2022, the NMPRC voted to reconsider its order and voted 3-2 to approve the stipulation without modification. New rates will go into effect on Feb. 26, 2022.

2021 Texas Rate Case — In February 2021, SPS filed an electric rate case with the PUCT and its municipalities, seeking an increase in base rates of approximately $140 million. SPS' proposed net rate increase to Texas customers was approximately $71 million, or 9.2%, as a result of the offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request was based on a ROE of 10.35%, an equity ratio of 54.60%, a rate base of approximately $3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020. The request included the effect of losing approximately 400 MW from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk power plant (from 2037 to 2032) and coal handling assets at the Harrington facility (to 2024).

In January 2022, SPS and intervenors filed a blackbox settlement. Key terms include:

- A base rate increase of approximately $89 million effective back to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for AFUDC purposes only.
- The depreciation lives for Tolk moved up to 2034 and Harrington coal assets moved up to 2024.

In February 2022, the ALJ issued an order approving interim rates to be effective on March 1, 2022. A PUCT decision is expected in the first quarter of 2022.

Purchased Power Arrangements and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements.

Purchased Power — SPS purchases power from other utilities and IPPs. Long-term purchased power contracts typically require periodic capacity and energy charges. SPS also makes short-term purchases to meet system load and energy requirements to replace owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers.

Natural Gas

SPS does not provide retail natural gas service, but purchases and transports natural gas for its generation facilities and operates limited natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce and the PHMSA and PUCT for pipeline safety compliance.

Wholesale and Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and to hedge sales and purchases.

Other Public Utility Matters

Comanche Unit 3 Outage

In January 2022, PSCo experienced an incident at the Comanche Unit 3 plant (750 MW, coal-fueled electric generating unit) resulting in damage and an outage that is expected to last approximately two months. PSCo has notified the CPUC and informed them that it will not seek recovery of any replacement power costs above the expected costs if Comanche 3 had been in service. The estimated incremental replacement power costs could be approximately $10 million, assuming a two month outage, normal weather and current market pricing.

Marshall Wildfire

In December 2021, a wildfire ignited in Boulder County, Colorado (the "Marshall Fire"), which burned over 6,000 acres and destroyed or damaged over 1,000 structures. While there were no downed power lines in the ignition area, the determination of the cause of the Marshall Fire is pending.

In Colorado, the standard of review governing liability differs from the "inverse condemnation" or strict liability standard utilized in California. In Colorado, courts look to whether electric power companies have operated their system with a heightened duty of care consistent with the practical conduct of its business, and liability does not extend to occurrences that cannot be reasonably anticipated. In addition, PSCo has been operating under a commission approved wildfire mitigation plan and carries wildfire liability insurance.

However, in the unlikely event we were found liable, the damages awarded could exceed our coverage and negatively impact our results of operations, financial conditions or cash flows.

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, Xcel Energy incurred net natural gas, fuel and purchased energy costs of approximately $1 billion (largely deferred as regulatory assets).

Regulatory Overview — Xcel Energy has natural gas, fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, the utility subsidiaries have deferred February 2021 cost increases for future recovery and sought recovery of the cost increases over a period of up to 63 months to mitigate the impact to customer bills. Additionally, we did not request recovery of financing costs in order to further limit the impact to our customers.

Proceedings initiated:

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	NSP-Minnesota filed with the MPUC seeking recovery of $215 million in incremental costs from natural gas customers. In August 2021, the MPUC allowed recovery of $179 million of costs deemed to be extraordinary beginning in September 2021 over 27 months (no financing charge) and $36 million of ordinary costs over 12 months through the monthly Purchased Gas Adjustment. The $179 million in extraordinary cost recovery is subject to refund pending the outcome of a contested case before an ALJ. In December 2021, the MPUC approved extending recovery of Winter Storm Uri costs for the residential class (approximately $97 million) from a 27-month recovery period to a 63-month recovery period. New residential Winter Storm Uri rates were effective Jan. 1, 2022. In December 2021, direct testimony was received from intervenors. The DOC recommended a $127 million disallowance based on allegations including peaking plant usage, load forecasting, natural gas supply/storage and related purchases. Alternatively, the DOC recommended a $42 million disallowance if NSP-Minnesota proves it prudently managed its peaking plants. The OAG recommended a disallowance of $179 million based on allegations that NSP-Minnesota could have fully hedged its exposure to spot market prices. Alternatively, the OAG recommended a $25 million disallowance based on allegations related to specific hedges allegedly available in the market during February 2021. The CUB recommended a $69 million disallowance based on allegations related to the unavailability of NSP-Minnesota's peaking plants, inaccuracy of load forecasting and inadequate curtailment of interruptible customers. Xcel Energy strongly disagrees with the recommendations of the DOC, OAG and CUB and believes that it acted prudently and according to MPUC approved procedures for the best interest of its customers and stakeholders. NSP-Minnesota filed rebuttal testimony in January 2022. A hearing before the ALJs assigned to the matter is scheduled for Feb. 17-23, 2022. An MPUC decision is expected in the summer of 2022. See Rate Matters and Other within Note 12 to the consolidated financial statements for further information.
	South Dakota	Winter Storm Uri had no impact on South Dakota electric costs as NSP-Minnesota was a net seller in the electric market.
	North Dakota	In June, the NDPSC approved recovery of $32 million in natural gas costs over 15 months (starting July 2021) with no financing charge.
NSP-Wisconsin	Wisconsin	In March, the PSCW approved NSP-Wisconsin's proposal to recover $45 million of Winter Storm Uri natural gas costs over nine months through December 2021 with no financing charge.
	Michigan	In May, the MPSC approved recovery of $2 million in natural gas costs over 10 months with no financing charge.
PSCo	Colorado	In May, PSCo filed a request with the CPUC to recover $263 million in weather-related electric costs, $287 million in incremental natural gas costs and $4 million in incremental steam costs over 24 months with no financing charge. In September, intervenors filed testimony. The CPUC Staff recommended disallowances of approximately $99 million (electric) and $105 million (natural gas). Additionally, they proposed to net approximately $50 million of regulatory liabilities (decoupling related) from electric costs. The Utility Consumer Advocate recommended disallowances of approximately $131 million. The COEO recommended disallowances of approximately $46 million for not utilizing demand response programs during the event. In October, a partial settlement was reached with the CPUC Staff and the COEO, allowing full recovery of Winter Storm Uri deferred net natural gas, fuel and purchased energy costs of $263 million (electric utility) and $287 million (natural gas utility) over a 24-month and 30-month period, respectively, with no carrying charges through a rider mechanism. A decision is expected in the first quarter of 2022. In addition, the CPUC is considering prospective changes in fuel cost recovery.
SPS	Texas	As part of the Texas fuel surcharge filing, SPS filed for recovery of $76 million, over 24 months, in under-collected purchased power and fuel costs through March 2021, subject to revision due to re-settlements. Of this amount, $62 million was attributed to Winter Storm Uri. In the third quarter, SPS filed a supplemental application and testimony to recover an additional $26 million in under-collected purchased power and fuel costs through June 2021 resulting primarily from SPP resettlements and continued increases in natural gas prices. In November 2021, the ALJ abated the hearing schedule to allow the parties to continue settlement negotiations. In December 2021, SPS filed its triennial Fuel Reconciliation, under which the PUCT will consider prudence of SPS' fuel costs for the period July 2018 - June 2021, including Winter Storm Uri. In January 2022, SPS and other parties filed a stipulation/motion for interim rates. The filing covers all fuel under-collections occurring between January 2020 and August 2021, totaling $121 million. The settlement does not address the prudence of Winter Storm Uri costs nor the retention of $11 million related to market sales during the event. These items will be reviewed through the triennial Fuel Reconciliation proceeding and are subject to a final PUCT decision. Interim rates, designed to collect up to $110 million over a period of 30 months, will begin on Feb. 1, 2022.
	New Mexico	In March 2021, the NMPRC approved SPS' request to recover $26 million of fuel costs over 24 months with no financing charge, subject to NMPRC review.

Potential Tax Reform

The U.S. Congress is currently discussing potential proposals that may impact federal tax law. At this time, it is unknown what, if any, changes may ultimately occur. Based on provisions passed by the U.S. House of Representatives in November 2021, known as the Build Back Better Act, if any of such provisions were to be enacted into law, we would not expect the impact of such changes to have a material impact on our earnings.

Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements requires the application of accounting rules and guidance, as well as the use of estimates. Application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and results reported.

Accounting policies and estimates that are most significant to Xcel Energy's results of operations, financial condition or cash flows, and require management's most difficult, subjective or complex judgments are outlined below. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy is subject to the accounting for Regulated Operations, which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. Our rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows.

Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or other comprehensive income.

Each reporting period we assess the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital, and may materially impact our results of operations, financial condition or cash flows.

As of Dec. 31, 2021 and 2020, Xcel Energy had regulatory assets of \$3.8 billion and \$3.4 billion, respectively and regulatory liabilities of \$5.7 billion and \$5.6 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs in any such jurisdiction is no longer probable, Xcel Energy would be required to charge these assets to current net income or other comprehensive income.

At Dec. 31, 2021, in assessing the probability of recovery of recognized regulatory assets, unless otherwise disclosed, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the recovery of the assets.

See Notes 4 and 12 to the consolidated financial statements for further information.

Income Tax Accruals

Judgment, uncertainty and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR.

Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our future ETR. ETR calculations are revised every quarter based on best available year-end tax assumptions, adjusted in the following year after returns are filed. Tax accrual estimates are trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted annual ETR. The forecasted ETR reflects a number of estimates, including forecasted annual income, permanent tax adjustments and tax credits.

Valuation allowances are applied to deferred tax assets if it is more likely than not that at least a portion may not be realized based on an evaluation of expected future taxable income. Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. We may adjust our unrecognized tax benefits and interest accruals as disputes with the IRS and state tax authorities are resolved, and as new developments occur. These adjustments may increase or decrease earnings.

See Note 7 to the consolidated financial statements for further information.

Employee Benefits

We sponsor several noncontributory, defined benefit pension plans and other postretirement benefit plans that cover almost all employees and certain retirees. Projected benefit costs are based on historical information and actuarial calculations that include key assumptions (annual return level on pension and postretirement health care investment assets, discount rates, mortality rates and health care cost trend rates, etc.). In addition, the pension cost calculation uses a methodology to reduce the volatility of investment performance over time. Pension assumptions are continually reviewed.

At Dec. 31, 2021, Xcel Energy set the rate of return on assets used to measure pension costs at 6.49%, which is consistent with the rate set in 2020. The rate of return used to measure postretirement health care costs is 4.10% at Dec. 31, 2021, which is consistent with the rate set in 2020.

Xcel Energy's pension investment strategy is based on plan-specific investments that seek to minimize investment and interest rate risk as a plan's funded status increases over time. This strategy results in a greater percentage of interest rate sensitive securities being allocated to plans with higher funded status ratios and a greater percentage of growth assets being allocated to plans having lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 3.08% and postretirement health care obligations at 3.09% at Dec. 31, 2021. This represents a 37 basis point and 44 basis point decrease, respectively, from 2020. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration.

The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Merrill Lynch Corporate 15+ Bond Index. In addition, Xcel Energy reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

If Xcel Energy were to use alternative assumptions, a 1% change would result in the following impact on 2021 pension costs:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (13)	$ 23
Discount rate [(a)]	$ 1	$ 15

(a) These costs include the effects of regulation.

Mortality rates are developed from actual and projected plan experience for pension plan and postretirement benefits. Xcel Energy's actuary conducts an experience study periodically to determine an estimate of mortality. Xcel Energy considers standard mortality tables, improvement factors and the plans actual experience when selecting a best estimate.

As of Dec. 31, 2021, the initial medical trend cost claim assumptions for Pre-65 was 5.3% and Post-65 was 4.9%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

Funding contributions in 2021 were $131 million and are expected to decline in the following years. Investment returns exceeded assumed levels in 2021, 2020 and 2019.

The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20% per year. As differences between actual and expected investment returns are incorporated into the market-related value, amounts are recognized in pension cost over the expected average remaining years of service for active employees (approximately 13 years in 2021).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $77 million in 2022 and $60 million in 2023, while the actual pension costs were $121 million in 2021 and $117 million in 2020. The expected decrease in 2022 and future year costs is primarily due to the reductions in loss amortizations.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2019 - 2022:

- $50 million in January 2022.
- $131 million in 2021.
- $150 million in 2020.
- $154 million in 2019.

Future amounts may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

Xcel Energy contributed $15 million, $11 million and $15 million during 2021, 2020 and 2019, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $9 million during 2022. Xcel Energy recovers employee benefits costs in its utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability.
- In 2021, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2021 pension settlement accounting expense. In addition, the Commission order approved escrow accounting treatment for pension and other post-employment benefit expenses.
- Regulatory Commissions in Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on GAAP. The Texas and Colorado electric retail jurisdictions and the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.
- In 2018, PSCo was required to create a regulatory liability to adjust postretirement health care costs to zero in order to match the amounts collected in rates in the Colorado Gas retail jurisdiction. In 2020, this requirement was extended to the Colorado Electric retail jurisdiction.

See Note 11 to the consolidated financial statements for further information.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions, it adjusts the carrying amount of both the ARO liability and related long-lived asset. ARO liabilities are accreted to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The nuclear decommissioning obligation is funded by the external decommissioning trust fund. Difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $2.1 billion in 2021 and $2.0 billion in 2020.

NSP-Minnesota obtains periodic independent cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. Estimates of future cash flows are highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning filing every three years. The filing covers all expenses for the decommissioning of the nuclear plants, including decontamination and removal of radioactive material.

The currently approved triennial filing was ordered by the MPUC in January 2019. This approval did not result in a change to the ARO liability. In December 2020, the MPUC ordered Xcel Energy to maintain the current accrual through 2021 to align with the approved one year stay out of the previously filed multi-year electric rate case. Also, in December 2020, Xcel Energy filed an accrual proposal with the MPUC to be effective in 2022 based on an updated independent cost study. In December 2021, Xcel Energy submitted its petition for approval of the 2022-2024 NSP-Minnesota's Nuclear Decommission Study and Assumptions. Xcel Energy anticipates the MPUC to deliberate on this filing in February 2022.

The following assumptions have a significant effect on the estimated nuclear obligation:

Timing — Decommissioning cost estimates are impacted by each facility's retirement date and timing of the actual decommissioning activities. Estimated retirement dates coincide with the expiration of each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method (required by the MPUC), which assumes prompt removal and dismantlement. Decommissioning activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology, experience and regulations could cause cost estimates to change significantly.

Escalation Rates — Escalation rates represent projected cost increases due to general inflation and increases in the cost of decommissioning activities. NSP-Minnesota used an escalation rate of 3.2% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.

Discount Rates — Changes in timing or estimated cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity.

If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately 3% to 7% have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating future costs including the method to be utilized, ultimate costs to decommission and planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially.

However, changes in estimates have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the assumptions and uncertainties for each area. The information and assumptions of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2021.

See Note 12 to the consolidated financial statements for further information.

Derivatives, Risk Management and Market Risk

We are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While we expect that the counterparties will perform under the contracts underlying its derivatives, the contracts expose us to some credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the nuclear decommissioning fund and pension fund and Xcel Energy's ability to earn a return on short-term investments.

Commodity Price Risk — We are exposed to commodity price risk in our electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Our risk management policy allows us to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

Wholesale and Commodity Trading Risk — Xcel Energy conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Our risk management policy allows management to conduct these activities within guidelines and limitations as approved by our risk management committee.

Fair value of net commodity trading contracts as of Dec. 31, 2021:

	Futures / Forwards Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [(a)]	$ (4)	$ (7)	$ —	$ (1)	$ (12)
NSP-Minnesota [(b)]	(1)	3	(9)	(8)	(15)
PSCo [(a)]	6	6	1	1	14
PSCo [(b)]	(37)	(48)	—	—	(85)
	$ (36)	$ (46)	$ (8)	$ (8)	$ (98)

	Options Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [(b)]	$ 1	$ —	$ —	$ 8	$ 9
PSCo [(b)]	27	29	—	—	56
	$ 28	$ 29	$ —	$ 8	$ 65

(a) Prices actively quoted or based on actively quoted prices.
(b) Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the years ended Dec. 31:

(Millions of Dollars)	2021	2020
Fair value of commodity trading net contracts outstanding at Jan. 1	$ (54)	$ (59)
Contracts realized or settled during the period	(54)	(9)
Commodity trading contract additions and changes during the period	75	14
Fair value of commodity trading net contracts outstanding at Dec. 31	$ (33)	$ (54)

At Dec. 31, 2021, a 10% increase in market prices for commodity trading contracts through the forward curve would increase pretax income from continuing operations by approximately $13 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $13 million. At Dec. 31, 2020, a 10% increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $13 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $13 million. Market price movements can exceed 10% under abnormal circumstances.

The utility subsidiaries' commodity trading operations measure the outstanding risk exposure to price changes on contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as VaR. VaR expresses the potential change in fair value on the outstanding contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, excluding both non-derivative transactions and derivative transactions designated as normal purchase and normal sales, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2021	$ 1	$ 3	$ 2	$ 52	$ 1
2020	1	3	1	2	1

A short-term increase in VaR occurred during the week of Feb. 12, 2021 through Feb. 18, 2021. On Feb. 17, 2021, the portfolio VaR reached a high of $52 million. This increase in VaR was driven by the unprecedented market conditions during Winter Storm Uri. Prior to this widespread weather event, VaR was $1 million and returned to $1 million by Feb. 19, 2021.

Nuclear Fuel Supply — NSP-Minnesota has contracted for approximately 78% of its 2022 enriched nuclear material requirements from sources that could be impacted by sanctions against entities doing business with Iran. Those sanctions may impact the supply of enriched nuclear material supplied from Russia. Long-term, through 2030, NSP-Minnesota is scheduled to take delivery of approximately 30% of its average enriched nuclear material requirements from these sources. NSP-Minnesota is able to manage nuclear fuel supply with alternate potential sources. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

Interest Rate Risk — Xcel Energy is subject to interest rate risk. Our risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $11 million and $6 million in 2021 and 2020, respectively.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. The fund is invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for the purpose of decommissioning NSP-Minnesota's nuclear generating plants.

Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting.

Changes in discount rates and expected return on plan assets impact the value of pension and postretirement plan assets and/or benefit costs.

Credit Risk — Xcel Energy is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy maintains credit policies intended to minimize overall credit risk and actively monitors these policies to reflect changes and scope of operations.

At Dec. 31, 2021, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $36 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $26 million. At Dec. 31, 2020, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $11 million, while a decrease in prices of 10% would have resulted in an immaterial increase in credit exposure.

Xcel Energy conducts credit reviews for all counterparties and employs credit risk controls, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored, and when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase our credit risk.

Fair Value Measurements

Xcel Energy uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase and normal sale contracts, are reported at fair value.

Xcel Energy's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

Commodity Derivatives — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. The impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2021.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2021.

See Notes 10 and 11 to the consolidated financial statements for further information.

Liquidity and Capital Resources

Cash Flows

Operating Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash provided by operating activities — 2020	$	2,848
Components of change — 2021 vs. 2020		
Higher net income		124
Non-cash transactions [(a)]		52
Changes in working capital [(b)]		(50)
Changes in net regulatory and other assets and liabilities		(785)
Cash provided by operating activities — 2021	$	2,189

(a) Non-cash transactions applicable to net income (e.g., depreciation, nuclear fuel amortization, changes in deferred income taxes, allowance for equity funds used during construction, etc.).

(b) Working capital includes accounts receivable, accrued unbilled revenues, inventories, accounts payable, other current assets and other current liabilities.

Net cash provided by operating activities decreased by $659 million for 2021 as compared to 2020. The decrease was primarily due to the deferral of net natural gas, fuel and purchased energy costs related to Winter Storm Uri in the first quarter.

Investing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash used in investing activities — 2020	$	(4,740)
Components of change — 2021 vs. 2020		
Decreased capital expenditures		1,125
Sale of MEC in 2020		(684)
Other investing activities		12
Cash used in investing activities — 2021	$	(4,287)

Net cash used in investing activities decreased by $453 million for 2021 as compared to 2020. The decrease in capital expenditures was largely due to the purchase of MEC in January 2020, which was subsequently sold in July 2020, as well as the completion of various wind projects.

Financing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash provided by financing activities — 2020	$	1,773
Components of change — 2021 vs. 2020		
Higher debt issuances		202
Lower repayments of long-term debt		584
Lower proceeds from issuance of common stock		(361)
Higher dividends paid to shareholders		(79)
Other financing activities		16
Cash provided by financing activities — 2021	$	2,135

Net cash provided by financing activities increased by $362 million for 2021 as compared to 2020. The increase was primarily attributable to the amount/timing of debt issuances and repayments, changes in capital investment and incremental financing due to the lag in recovery costs associated with Winter Storm Uri.

See Note 5 to the consolidated financial statements for further information.

Capital Requirements

Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The Company expects to have adequate amounts of cash from operating and/or financing activities to meet both its short-term and long-term cash requirements. Xcel Energy's financing requirements are dependent on both existing contractual obligations and other commitments, as well as projected capital forecasts. Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios. Projected future financing requirements can be impacted by various factors including constraints to supply chain and labor, as well as inflation.

Recovery of the effects of inflation through higher customer rates is dependent upon receiving adequate and timely rate increases. Rate increases may not be retroactive and often lag increases in costs caused by inflation. On occasion, the Company may enter into rate settlement agreements, which require us to wait for a period of time to file the next base rate increase request. These agreements may result in regulatory lag whereby the impact of inflation may not yet be reflected in rates, or a delay may occur between capital project completion and the start of rate recovery. Xcel Energy attempts to mitigate the potential impact of inflation through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances.

Contractual Obligations and Other Commitments

(Millions of Dollars)	Payments Due by Period (as of Dec. 31, 2021) Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	After 5 Years
Long-term debt, principal and interest payments	$ 37,014	$ 1,419	$ 3,323	$ 3,175	$ 29,097
Finance lease obligations	242	12	24	19	187
Operating leases obligations [(a)]	1,594	256	478	363	497
Unconditional purchase obligations [(b)]	4,837	1,718	1,538	617	964
Other long-term obligations, including current portion [(c)]	40	36	4	—	—
Other short-term obligations	455	455	—	—	—
Short-term debt	1,005	1,005	—	—	—
Total contractual cash obligations	$ 45,187	$ 4,901	$ 5,367	$ 4,174	$ 30,745

(a) Included in operating lease obligations are $229 million, $430 million, $335 million and $416 million, for the less than 1 year, 1 - 3 years, 3 - 5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

(b) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its fuel (nuclear, natural gas and coal) requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into non-lease purchase power agreements. Certain contractual purchase obligations are adjusted on indices. Effects of price changes are mitigated through cost of energy adjustment mechanisms.

(c) Primarily consists of contracts for information technology services.

Capital Expenditures — Base capital expenditures and incremental capital forecasts:

By Regulated Utility	Actual 2021	Base Capital Forecast (Millions of Dollars) 2022	2023	2024	2025	2026	2022 - 2026 Total
PSCo	$ 1,625	$ 1,930	$ 1,850	$ 2,070	$ 2,220	$ 1,860	$ 9,930
NSP-Minnesota	1,885	2,250	2,030	1,830	2,130	2,010	10,250
SPS	555	630	660	690	780	790	3,550
NSP-Wisconsin	290	480	420	540	460	390	2,290
Other [(a)]	25	(10)	—	10	(30)	10	(20)
Total base capital expenditures	$ 4,380	$ 5,280	$ 4,960	$ 5,140	$ 5,560	$ 5,060	$ 26,000

By Function	Actual 2021	Base Capital Forecast (Millions of Dollars) 2022	2023	2024	2025	2026	2022 - 2026 Total
Electric distribution	$ 1,110	$ 1,485	$ 1,600	$ 1,520	$ 1,605	$ 1,720	$ 7,930
Electric transmission	830	1,105	1,220	1,575	1,965	1,555	7,420
Electric generation	575	645	580	670	650	650	3,195
Natural gas	655	655	670	695	660	660	3,340
Other	610	725	545	450	340	450	2,510
Renewables	600	665	345	230	340	25	1,605
Total base capital expenditures	$ 4,380	$ 5,280	$ 4,960	$ 5,140	$ 5,560	$ 5,060	$ 26,000

(a) Other category includes intercompany transfers for safe harbor wind turbines.

The five-year capital forecast includes the proposed Colorado Pathway transmission expansion (approximately $1.7 billion) and the proposed 460 MW Sherco solar facility (approximately $600 million).

Additional capital investment in renewable generation and transmission may be needed in the five-year forecast pending approval of regulatory filings in Minnesota and Colorado. The approval of the proposed resource plans could result in up to 2,000 MW of renewable generation being needed between 2024 - 2026, resulting in potential capital expenditures estimated between $1.0 to $1.5 billion (assuming Xcel Energy were to own ~50% of the renewables). Additionally, the associated $0.5 billion to $1.0 billion of network upgrades, voltage support and interconnection work related to the Colorado Power Pathway could also be needed during this five-year forecast depending on resource mix, location and timing. Any additional capital investment would likely be funded with approximately 50% equity and 50% debt.

Xcel Energy’s capital expenditure forecast is subject to continuing review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, safety and reliability needs, regulatory decisions, legislative initiatives (e.g., federal clean energy and tax policy), reserve requirements, availability of purchased power, alternative plans for meeting long-term energy needs, environmental initiatives and regulation, and merger, acquisition and divestiture opportunities.

Financing for Capital Expenditures through 2026 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

Current estimated financing plans of Xcel Energy for 2022 through 2026:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from operations [(a)]	$ 17,640
New debt [(b)]	7,110
Equity through the DRIP and benefit program	450
Other equity	800
Base capital expenditures 2021 - 2025	$ 26,000
Maturing Debt	$ 3,900

(a) Net of dividends and pension funding.
(b) Reflects a combination of short and long-term debt; net of refinancing.

Off-Balance Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial condition, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. In February 2022, Xcel Energy announced an increase in the annual dividend of 12 cents per share, which represents an increase of 6.6%.

Xcel Energy's dividend policy balances the following:

- Projected cash generation.
- Projected capital investment.
- A reasonable rate of return on shareholder investment.
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places limits on the ability of public utilities within a holding company to declare dividends. Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants.

See Note 5 to the consolidated financial statements for further information.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income securities and alternative investments, including private equity, real estate and hedge funds.

Funded status and pension assumptions:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Fair value of pension assets	$ 3,670	$ 3,599
Projected pension obligation [(a)]	3,718	3,964
Funded status	$ (48)	$ (365)

(a) Excludes non-qualified plan of $43 million and $43 million at Dec. 31, 2021 and 2020, respectively.

Pension Assumptions	2021	2020
Discount rate	3.08 %	2.71 %
Expected long-term rate of return	6.49	6.49

Capital Sources

Short-Term Funding Sources — Xcel Energy generally funds short-term needs, through operating cash flows, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend on construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash and short-term investment accounts.

Short-Term Debt — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. Authorized levels for these commercial paper programs are:

- $1.25 billion for Xcel Energy Inc.
- $700 million for PSCo.
- $500 million for NSP-Minnesota.
- $500 million for SPS.
- $150 million for NSP-Wisconsin.

Xcel Energy Inc. repaid its $1.2 billion 364-Day Term Loan Agreement in the fourth quarter.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2021
Borrowing limit	$ 3,100
Amount outstanding at period end	1,005
Average amount outstanding	1,200
Maximum amount outstanding	1,774
Weighted average interest rate, computed on a daily basis	0.54 %
Weighted average interest rate at end of period	0.31

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 3,100	$ 3,100
Amount outstanding at period end	1,005	584
Average amount outstanding	1,399	1,126
Maximum amount outstanding	2,054	2,080
Weighted average interest rate, computed on a daily basis	0.57 %	1.45 %
Weighted average interest rate at end of period	0.31	0.23

Credit Facility Agreements — Xcel Energy Inc., NSP-Minnesota, PSCo and SPS each have the right to request an extension of the revolving credit facility for two additional one-year periods beyond the June 2024 termination date. NSP-Wisconsin has the right to request an extension of the revolving credit facility for an additional year. All extension requests are subject to majority bank group approval.

As of Feb. 18, 2022, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,250	$ 757	$ 493	$ 2	$ 495
PSCo	700	26	674	22	696
NSP-Minnesota	500	11	489	13	502
SPS	500	235	265	3	268
NSP-Wisconsin	150	—	150	3	153
Total	$ 3,100	$ 1,029	$ 2,071	$ 43	$ 2,114

(a) Credit facilities expire in June 2024.
(b) Includes outstanding commercial paper and letters of credit.

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2021 and 2020, Xcel Energy had approximately 544 million shares and 537 million shares of common stock outstanding, respectively.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC pursuant to which they may sell securities from time to time. These registration statements, which are uncapped, permit Xcel Energy Inc. and its utility subsidiaries to issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings, and in the case of our utility subsidiaries, subject to commission approval.

Planned Financing Activity — Xcel Energy's 2022 financing plans reflect the following:

- Xcel Energy Inc. — approximately $600 million in unsecured bonds during Q2.
- PSCo — approximately $650 million of first mortgage bonds during Q2.
- SPS — approximately $150 million of first mortgage bonds during Q2.
- NSP-Minnesota — approximately $500 million of first mortgage bonds during Q2.
- NSP-Wisconsin — approximately $100 million of first mortgage bonds during Q3.

Equity through DRIP and Benefits Program — Xcel Energy also plans to issue approximately $90 million of equity annually through the DRIP and benefit programs during the five-year forecast time period.

ATM Equity Offering — In November 2021, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $800 million of its common stock through an ATM program. As of Dec. 31, 2021, Xcel Energy Inc. issued 5.33 million shares of common stock with net proceeds of $347 million through the ATM program.

Long-Term Borrowings and Other Financing Instruments — See Note 5 to the consolidated financial statements for further information.

Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2022 Earnings Guidance — Xcel Energy's 2022 GAAP and ongoing earnings guidance is a range of $3.10 to $3.20 per share.[a]

Key assumptions as compared with 2021 levels unless noted:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the year.
- Weather-normalized retail electric sales are projected to increase ~1%.
- Weather-normalized retail firm natural gas sales are projected to be 0% to 1%.
- Capital rider revenue is projected to increase $35 million to $45 million (net of PTCs). PTCs are credited to customers, through capital riders and reductions to other regulatory mechanisms.
- O&M expenses are projected to increase approximately 1% to 2%.
- Depreciation expense is projected to increase approximately $255 million to $265 million.
- Property taxes are projected to increase approximately $40 million to $50 million.
- Interest expense (net of AFUDC - debt) is projected to increase $55 million to $65 million.
- AFUDC - equity is projected to be relatively flat.
- ETR is projected to be ~(3%) to (5%). The ETR reflects benefits of PTCs which are credited to customers through electric margin and will not have a material impact on net income.

(a) Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations. Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing EPS to corresponding GAAP EPS.

Long-Term EPS and Dividend Growth Rate Objectives — Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 5% to 7% based off of a 2021 base of $2.96 per share, which represents the mid-point of the revised 2021 guidance range of $2.94 to $2.98 per share.
- Deliver annual dividend increases of 5% to 7%.
- Target a dividend payout ratio of 60% to 70%.
- Maintain senior secured debt credit ratings in the A range.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See the "Derivatives, Risk Management and Market Risk" section in Item 7, incorporated by reference.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See Item 15-1 for an index of financial statements included herein.

See Note 15 to the consolidated financial statements for further information.

Management Report on Internal Control Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2021. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework (2013). Based on our assessment, we believe that, as of Dec. 31, 2021, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an attestation report on Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ ROBERT C. FRENZEL	/s/ BRIAN J. VAN ABEL
Robert C. Frenzel	Brian J. Van Abel
Chairman, President, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer
Feb. 23, 2022	Feb. 23, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Xcel Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

***Regulatory Assets and Liabilities - Impact of Rate Regulation on the Financial Statements — Refer to Notes 4 and 12 to the consolidated financial statements*.**

Critical Audit Matter Description

The Company is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota, South Dakota, Wisconsin, Michigan, Colorado, New Mexico, and Texas. The Company is also subject to the jurisdiction of the Federal Energy Regulatory Commission for its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with North American Electric Reliability Corporation standards, asset transactions and mergers and natural gas transactions in interstate commerce, (collectively with state utility regulatory agencies, the “Commissions”). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant and equipment, regulatory assets and liabilities, operating revenues and expenses, and income taxes.

The Company is subject to regulatory rate setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the Company’s costs to provide utility service and a return on, and recovery of, the Company’s investment in assets required to deliver services to customers. Accounting for the Company’s regulated operations provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. The Commissions’ regulation of rates is premised on the full recovery of incurred costs and a reasonable rate of return on invested capital. Decisions by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. In the rate setting process, the Company’s rates result in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant, and 3) a refund due to customers. Given that management’s accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management’s controls over the recognition of regulatory assets or liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company, regulatory statutes, interpretations, procedural schedules and memorandums, filings made by intervenors, experts’ testimony and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions’ treatment of similar costs under similar circumstances. We also evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects. If the full recovery of project costs is being challenged by intervenors, we evaluated management’s assessment of the probability of a disallowance. We evaluated the external information and compared to the Company’s recorded regulatory assets and liabilities for completeness.
- We obtained management’s analysis and correspondence from counsel, as appropriate, regarding regulatory assets or liabilities not yet addressed in a regulatory order to assess management’s assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 23, 2022

We have served as the Company’s auditor since 2002.

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2021	2020	2019
Operating revenues			
Electric	$ 11,205	$ 9,802	$ 9,575
Natural gas	2,132	1,636	1,868
Other	94	88	86
Total operating revenues	13,431	11,526	11,529
Operating expenses			
Electric fuel and purchased power	4,733	3,512	3,510
Cost of natural gas sold and transported	1,081	689	918
Cost of sales — other	38	37	40
Operating and maintenance expenses	2,321	2,324	2,338
Conservation and demand side management expenses	304	288	285
Depreciation and amortization	2,121	1,948	1,765
Taxes (other than income taxes)	630	612	569
Total operating expenses	11,228	9,410	9,425
Operating income	2,203	2,116	2,104
Other income (expense), net	5	(6)	16
Earnings from equity method investments	62	40	39
Allowance for funds used during construction — equity	73	115	77
Interest charges and financing costs			
Interest charges — includes other financing costs of $29, $28 and $26, respectively	842	840	773
Allowance for funds used during construction — debt	(26)	(42)	(37)
Total interest charges and financing costs	816	798	736
Income before income taxes	1,527	1,467	1,500
Income tax (benefit) expense	(70)	(6)	128
Net income	$ 1,597	$ 1,473	$ 1,372
Weighted average common shares outstanding:			
Basic	539	527	519
Diluted	540	528	520
Earnings per average common share:			
Basic	$ 2.96	$ 2.79	$ 2.64
Diluted	2.96	2.79	2.64

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2021	2020	2019
Net income	$ 1,597	$ 1,473	$ 1,372
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of $—, $(2) and $—, respectively	—	(5)	—
Reclassification of losses to net income, net of tax of $3, $3 and $1, respectively	8	10	3
Derivative instruments:			
Net fair value increase (decrease), net of tax of $1, $(3) and $(8), respectively	4	(10)	(23)
Reclassification of losses to net income, net of tax of $2, $2 and $1, respectively	6	5	3
Total other comprehensive income (loss)	18	—	(17)
Total comprehensive income	$ 1,615	$ 1,473	$ 1,355

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2021	2020	2019
Operating activities			
Net income	$ 1,597	$ 1,473	$ 1,372
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	2,143	1,959	1,785
Nuclear fuel amortization	114	123	119
Deferred income taxes	(79)	(8)	143
Allowance for equity funds used during construction	(73)	(115)	(77)
Earnings from equity method investments	(62)	(40)	(39)
Dividends from equity method investments	42	42	40
Provision for bad debts	60	60	42
Share-based compensation expense	31	73	58
Net realized and unrealized hedging and derivative transactions	(57)	(27)	45
Changes in operating assets and liabilities:			
Accounts receivable	(164)	(154)	(20)
Accrued unbilled revenues	(149)	(3)	42
Inventories	(126)	(80)	(84)
Other current assets	(34)	(45)	25
Accounts payable	138	(33)	(12)
Net regulatory assets and liabilities	(973)	(144)	(66)
Other current liabilities	(1)	29	(15)
Pension and other employee benefit obligations	(135)	(125)	(135)
Other, net	(83)	(137)	40
Net cash provided by operating activities	2,189	2,848	3,263
Investing activities			
Capital/construction expenditures	(4,244)	(5,369)	(4,225)
Sale of MEC	—	684	—
Purchase of investment securities	(757)	(1,398)	(995)
Proceeds from the sale of investment securities	743	1,378	975
Other, net	(29)	(35)	(98)
Net cash used in investing activities	(4,287)	(4,740)	(4,343)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	421	(11)	(443)
Proceeds from issuances of long-term debt	2,710	2,940	2,920
Repayments of long-term debt, including reacquisition premiums	(417)	(1,001)	(949)
Proceeds from issuance of common stock	366	727	458
Dividends paid	(935)	(856)	(791)
Other, net	(10)	(26)	(14)
Net cash provided by financing activities	2,135	1,773	1,181
Net change in cash and cash equivalents	37	(119)	101
Cash, cash equivalents and restricted cash at beginning of period	129	248	147
Cash, cash equivalents and restricted cash at end of period	$ 166	$ 129	$ 248
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (788)	$ (758)	$ (698)
Cash (paid) received for income taxes, net	(4)	12	53
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 501	$ 400	$ 421
Inventory transfers to property, plant and equipment	87	275	88
Operating lease right-of-use assets	8	369	1,843
Allowance for equity funds used during construction	73	115	77
Issuance of common stock for reinvested dividends and/or equity awards	60	67	63

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in millions, except share and per share)

	Dec. 31	
	2021	**2020**
Assets		
Current assets		
Cash and cash equivalents	$ 166	$ 129
Accounts receivable, net	1,018	916
Accrued unbilled revenues	862	714
Inventories	631	535
Regulatory assets	1,106	640
Derivative instruments	123	49
Prepaid taxes	44	42
Prepayments and other	289	250
Total current assets	4,239	3,275
Property, plant and equipment, net	45,457	42,950
Other assets		
Nuclear decommissioning fund and other investments	3,628	3,096
Regulatory assets	2,738	2,737
Derivative instruments	67	30
Operating lease right-of-use assets	1,291	1,490
Other	431	379
Total other assets	8,155	7,732
Total assets	$ 57,851	$ 53,957
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 601	$ 421
Short-term debt	1,005	584
Accounts payable	1,409	1,237
Regulatory liabilities	271	311
Taxes accrued	569	578
Accrued interest	209	203
Dividends payable	249	231
Derivative instruments	69	53
Operating lease liabilities	205	214
Other	459	407
Total current liabilities	5,046	4,239
Deferred credits and other liabilities		
Deferred income taxes	4,894	4,746
Deferred investment tax credits	53	45
Regulatory liabilities	5,405	5,302
Asset retirement obligations	3,151	2,884
Derivative instruments	105	131
Customer advances	196	197
Pension and employee benefit obligations	306	666
Operating lease liabilities	1,146	1,344
Other	158	183
Total deferred credits and other liabilities	15,414	15,498
Commitments and contingencies		
Capitalization		
Long-term debt	21,779	19,645
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 544,025,269 and 537,438,394 shares outstanding at Dec. 31, 2021 and Dec. 31, 2020, respectively	1,360	1,344
Additional paid in capital	7,803	7,404
Retained earnings	6,572	5,968
Accumulated other comprehensive loss	(123)	(141)
Total common stockholders' equity	15,612	14,575
Total liabilities and equity	$ 57,851	$ 53,957

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(amounts in millions, except per share data; shares in actual amounts)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2018	514,036,787	$ 1,285	$ 6,168	$ 4,893	$ (124)	$ 12,222
Net income				1,372		1,372
Other comprehensive income					(17)	(17)
Dividends declared on common stock ($1.62 per share)				(846)		(846)
Issuances of common stock	10,507,943	26	468			494
Repurchases of common stock	(5,730)	—	—			—
Share-based compensation			20	(6)		14
Balance at Dec. 31, 2019	524,539,000	$ 1,311	$ 6,656	$ 5,413	$ (141)	$ 13,239
Net Income				1,473		1,473
Dividends declared on common stock ($1.72 per share)				(909)		(909)
Issuances of common stock	12,953,869	33	731			764
Repurchase of common stock	(54,475)	—	(4)			(4)
Share-based compensation			21	(7)		14
Adoption of ASC Topic 326				(2)		(2)
Balance at Dec. 31, 2020	537,438,394	$ 1,344	$ 7,404	$ 5,968	$ (141)	$ 14,575
Net income				1,597		1,597
Other comprehensive income					18	18
Dividends declared on common stock ($1.83 per share)				(989)		(989)
Issuances of common stock	6,586,875	16	387			403
Share-based compensation			12	(4)		8
Balance at Dec. 31, 2021	544,025,269	$ 1,360	$ 7,803	$ 6,572	$ (123)	$ 15,612

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

General — Xcel Energy Inc.'s utility subsidiaries are engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas.

Xcel Energy's regulated operations include the activities of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in regulated operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipeline, storage and compression facilities.

Xcel Energy Inc.'s nonregulated subsidiaries include Eloigne, Capital Services, Venture Holdings and Nicollet Project Holdings. Eloigne invests in rental housing projects that qualify for low-income housing tax credits. Capital Services procures equipment for construction of renewable generation facilities at other subsidiaries. Venture Holdings invests in limited partnerships, including EIP funds with portfolios of investments in energy technology companies. Nicollet Project Holdings invests in nonregulated assets such as the MEC generating facility (through July 2020) and Minnesota community solar gardens. Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., Xcel Energy Transmission Holding Company, LLC, Nicollet Holdings Company, LLC, Xcel Energy Nuclear Services Holdings, LLC and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. All intercompany transactions and balances are eliminated unless a different treatment is appropriate for rate regulated transactions. Xcel Energy uses the equity method of accounting for its investments in EIP funds and WYCO.

Xcel Energy has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income.

Xcel Energy's consolidated financial statements are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts. Certain amounts in the consolidated financial statements or notes have been reclassified for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

Xcel Energy has evaluated events occurring after Dec. 31, 2021 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — Xcel Energy uses estimates based on the best information available in recording transactions and balances resulting from business operations.

Estimates are used for items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — Xcel Energy Inc.'s regulated utility subsidiaries account for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, the utility subsidiaries may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities.

Xcel Energy uses rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries' net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which would be refundable to utility customers over the remaining life of the related assets. Xcel Energy anticipates that a tax rate increase would result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Xcel Energy reports interest and penalties related to income taxes within other (expense) income or interest charges in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation in Regulated Operations — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Xcel Energy records depreciation expense using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs of Xcel Energy's utility subsidiaries are recovered in rates as authorized by the appropriate regulatory entities. The amount of removal costs is based on current factors used in existing depreciation rates. Accumulated removal costs are reflected in the consolidated balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.5% for 2021, 3.4% for 2020 and 3.3% for 2019.

See Note 3 for further information.

AROs — Xcel Energy accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 12 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility's expected service life, typically based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Notes 10 and 12 for further information.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 11 for further information.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 12 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. Xcel Energy recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

Xcel Energy does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. Xcel Energy presents its revenues net of any excise or sales taxes or fees. The utility subsidiaries recognize physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO are recorded on a net basis in cost of sales.

See Note 6 for further information.

Cash and Cash Equivalents — Xcel Energy considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

As of Dec. 31, 2021 and 2020, the allowance for bad debts was $106 million and $79 million, respectively.

Inventory — Inventory is recorded at average cost and consisted of the following:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Inventories		
Materials and supplies	$ 289	$ 275
Fuel	182	176
Natural gas	160	84
Total inventories	$ 631	$ 535

Equity Method Investments — The equity method of accounting is used for investments in WYCO and EIP funds, which results in Xcel Energy's recognition of its share of these investees' GAAP pretax earnings, based on Xcel Energy's proportional ownership interest. For investments in EIP funds, this includes Xcel Energy's share of fund expenses and realized gains and losses, as well as unrealized gains and losses resulting from valuations of the funds' investments in emerging energy technology companies.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements.

Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues and interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

See Note 10 for further information.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the consolidated statements of income.

Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 10 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling/sales true up and CIP/DSM programs) qualify as alternative revenue programs. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate or from other instances where the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs — Costs incurred for DSM and CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emission allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling costs. This method amortizes costs over the period between refueling outages consistent with rate recovery.

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. In certain jurisdictions, Xcel Energy reduces recoverable fuel and purchased power costs for the cost of RECs received. An inventory accounting model is used to account for RECs recognized on the consolidated balance sheets, however these assets are classified as regulatory assets if amounts are recoverable in future rates.

Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Cost of RECs that are utilized to support commodity trading activities are recorded in a similar manner as the associated commodities and are shown on a net basis in electric operating revenues in the consolidated statements of income.

2. Accounting Pronouncements

Recently Adopted

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

Xcel Energy implemented the guidance using a modified-retrospective approach, recognizing a cumulative effect charge of $2 million (after tax) to retained earnings on Jan. 1, 2020. Other than first-time recognition of an allowance for bad debts on accrued unbilled revenues, the Jan. 1, 2020, adoption of ASC Topic 326 did not have a significant impact on Xcel Energy's consolidated financial statements.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Property, plant and equipment, net		
Electric plant	$ 48,680	$ 47,104
Natural gas plant	7,758	7,135
Common and other property	2,602	2,503
Plant to be retired [(a)]	1,200	677
CWIP	1,969	1,877
Total property, plant and equipment	62,209	59,296
Less accumulated depreciation	(17,060)	(16,657)
Nuclear fuel	3,081	2,970
Less accumulated amortization	(2,773)	(2,659)
Property, plant and equipment, net	$ 45,457	$ 42,950

(a) Includes regulator-approved retirements of Comanche Units 1 and 2 and jointly owned Craig Unit 1 for PSCo, and Sherco Units 1, 2 and 3 and A.S. King for NSP-Minnesota. Also includes SPS' expected retirement of Tolk and conversion of Harrington to natural gas, and PSCo's planned retirement of jointly owned Craig Unit 2.

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2021:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
NSP-Minnesota			
Electric generation:			
Sherco Unit 3	$ 620	$ 451	59 %
Sherco common facilities	178	108	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	3	50
Huntley Wilmarth	48	1	50
CapX2020	952	127	51
Total NSP-Minnesota [(a)]	$ 1,814	$ 694	

(a) Projects additionally include $7 million in CWIP.

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
NSP-Wisconsin			
Electric transmission:			
La Crosse, WI to Madison, WI	$ 177	$ 15	37 %
CapX2020	169	28	80
Total NSP-Wisconsin [(a)]	$ 346	$ 43	

(a) Projects additionally include $2 million in CWIP.

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
PSCo			
Electric generation:			
Hayden Unit 1	$ 156	$ 99	76 %
Hayden Unit 2	151	78	37
Hayden common facilities	42	27	53
Craig Units 1 and 2	81	48	10
Craig common facilities	39	25	7
Comanche Unit 3	917	154	67
Comanche common facilities	28	2	82
Electric transmission:			
Transmission and other facilities	182	63	Various
Gas transmission:			
Rifle, CO to Avon, CO	22	8	60
Gas transmission compressor	8	2	50
Total PSCo [(a)]	$ 1,626	$ 506	

(a) Projects additionally include $4 million in CWIP.

Each company's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2021		Dec. 31, 2020	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	11	Various	$ 77	$ 944	$ 82	$ 1,268
Deferred natural gas, electric, steam energy/fuel costs		One to five years	504	543	14	18
Recoverable deferred taxes on AFUDC		Plant lives	—	289	—	283
Excess deferred taxes — TCJA	7	Various	14	219	16	229
Depreciation differences		One to 10 years	16	173	16	154
Environmental remediation costs	1, 12	Various	14	92	16	113
Texas revenue surcharges		One to two years	20	64	54	17
Sales true-up and revenue decoupling		One to two years	33	56	101	28
Benson biomass PPA termination and asset purchase		Eight years	10	55	10	65
Renewable resources and environmental initiatives		One to two years	170	48	129	12
PI extended power uprate		13 years	4	46	3	49
Purchased power contract costs		Term of related contract	9	45	7	54
Conservation programs [(a)]	1	One to two years	21	35	26	36
Losses on reacquired debt		Term of related debt	3	35	4	38
Contract valuation adjustments [(b)]	1, 10	Term of related contract	22	34	23	48
State commission adjustments		Plant lives	1	32	1	32
Laurentian biomass PPA termination		Two years	18	18	18	36
Nuclear refueling outage costs	1	One to two years	37	16	28	10
Property tax		Various	16	16	16	21
Gas pipeline inspection and remediation costs		One to two years	33	12	26	9
Net AROs [(c)]	1, 12	Various	—	(112)	—	139
Other		Various	84	78	50	78
Total regulatory assets			$ 1,106	$ 2,738	$ 640	$ 2,737

(a) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.
(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.
(c) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2021		Dec. 31, 2020	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 26	$ 3,230	$ 20	$ 3,368
Plant removal costs	1, 12	Various	—	1,655	—	1,520
Effects of regulation on employee benefit costs [(b)]		Various	—	235	—	221
Renewable resources and environmental initiatives		Various	1	101	5	59
ITC deferrals	1	Various	—	53	—	51
Revenue decoupling		One to two years	9	41	10	41
Contract valuation adjustments [(c)]	1, 10	One to three years	56	1	19	—
Deferred natural gas, electric, steam energy/fuel costs		Less than one year	50	—	84	—
Conservation programs [(d)]	1	Less than one year	42	—	49	—
DOE settlement		Less than one year	14	14	23	—
Other		Various	73	75	101	42
Total regulatory liabilities [(e)]			$ 271	$ 5,405	$ 311	$ 5,302

(a) Includes the revaluation of recoverable/regulated plant accumulated deferred income taxes and revaluation impact of non-plant accumulated deferred income taxes due to the TCJA.
(b) Includes regulatory amortization and certain 2018 TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset.
(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.
(d) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.
(e) Revenue subject to refund of $17 million for both 2021 and 2020 is included in other current liabilities.

At Dec. 31, 2021 and 2020, Xcel Energy's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, regulatory assets included $1,718 million and $812 million at Dec. 31, 2021 and 2020, respectively, of past expenditures not earning a return. Amounts are related to funded pension obligations, sales true-up and revenue decoupling, purchased natural gas and electric energy costs (including those related to Winter Storm Uri), various renewable resources and certain environmental initiatives.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Short-Term Debt — Xcel Energy meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities and term loan agreements.

Commercial paper and term loan borrowings outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2021	Year Ended Dec. 31 2021	2020	2019
Borrowing limit	$ 3,100	$3,100	$3,100	$3,600
Amount outstanding at period end	1,005	1,005	584	595
Average amount outstanding	1,200	1,399	1,126	1,115
Maximum amount outstanding	1,774	2,054	2,080	1,780
Weighted average interest rate, computed on a daily basis	0.54 %	0.57 %	1.45 %	2.72 %
Weighted average interest rate at period end	0.31	0.31	0.23	2.34

Term Loan Agreements — In the fourth quarter of 2021, Xcel Energy repaid its $1.2 billion 364-Day Term Loan Agreement.

Bilateral Credit Agreement — In April 2021, NSP-Minnesota's uncommitted bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of Dec. 31, 2021, NSP-Minnesota had $45 million outstanding letters of credit under the $75 million the Bilateral Credit Agreement.

Letters of Credit — Xcel Energy uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2021 and 2020, there were $19 million and $20 million of letters of credit outstanding under the credit facilities, respectively. Amounts approximate their fair value.

Credit Facilities — In order to use commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Terms of Credit Agreements — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements is $3.1 billion, with a swingline subfacility for Xcel Energy up to $75 million. The amended credit agreements mature in June 2024.

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio [(a)] 2021	2020	Amount Facility May Be Increased (millions of dollars)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
Xcel Energy Inc. [(c)]	60 %	59 %	$ 250	2
NSP-Wisconsin	49	46	N/A	1
NSP-Minnesota	47	47	100	2
SPS	47	48	50	2
PSCo	44	44	100	2

(a) Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.
(b) All extension requests are subject to majority bank group approval.
(c) The Xcel Energy Inc. credit facility has a cross-default provision that Xcel Energy Inc. would be in default on its borrowings under the facility if it or any of its subsidiaries (except NSP-Wisconsin as long as its total assets do not comprise more than 15% of Xcel Energy's consolidated total assets) default on indebtedness in an aggregate principal amount exceeding $75 million.

If Xcel Energy Inc. or its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2021, Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants.

Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available as of Dec. 31, 2021:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available
Xcel Energy Inc.	$ 1,250	$ 638	$ 612
PSCo	700	155	545
NSP-Minnesota	500	9	491
SPS	500	139	361
NSP-Wisconsin	150	83	67
Total	$ 3,100	$ 1,024	$ 2,076

(a) These credit facilities mature in June 2024.
(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its utility subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2021 and 2020.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are subject to the liens of their first mortgage indentures. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long-term debt obligations for Xcel Energy Inc. and its utility subsidiaries as of Dec. 31 (in millions of dollars):

Xcel Energy Inc.

Financing Instrument	Interest Rate	Maturity Date	2021	2020
Unsecured senior notes	2.40 %	March 15, 2021	$ —	$ 400
Unsecured senior notes [(b)]	0.50	Oct. 15, 2023	500	500
Unsecured senior notes	3.30	June 1, 2025	250	250
Unsecured senior notes	3.30	June 1, 2025	350	350
Unsecured senior notes	3.35	Dec. 1, 2026	500	500
Unsecured senior notes [(a)]	1.75	March 15,2027	500	—
Unsecured senior notes	4.00	June 15, 2028	130	130
Unsecured senior notes	4.00	June 15, 2028	500	500
Unsecured senior notes	2.60	Dec. 1, 2029	500	500
Unsecured senior notes [(b)]	3.40	June 1, 2030	600	600
Unsecured senior notes [(a)]	2.35	Nov. 15, 2031	300	—
Unsecured senior notes	6.50	July 1, 2036	300	300
Unsecured senior notes	4.80	Sep. 15, 2041	250	250
Unsecured senior notes	3.50	Dec. 1, 2049	500	500
Unamortized discount			(8)	(7)
Unamortized debt issuance cost			(33)	(32)
Current maturities			—	(400)
Total long-term debt			$ 5,139	$ 4,341

(a) 2021 financing.
(b) 2020 financing.

NSP-Minnesota

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	2.15 %	Aug. 15, 2022	$ 300	$ 300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.125	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds [(a)]	2.25	April 1, 2031	425	—
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.125	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sep. 15, 2047	600	600
First mortgage bonds	2.90	March 1, 2050	600	600
First mortgage bonds [(b)]	2.60	June 1, 2051	700	700
First mortgage bonds [(a)]	3.20	April 1,2052	425	—
Other long-term debt			3	—
Unamortized discount			(44)	(42)
Unamortized debt issuance cost			(62)	(54)
Current maturities			(300)	—
Total long-term debt			$ 6,447	$ 5,904

(a) 2021 financing.
(b) 2020 financing.

NSP-Wisconsin

Financing Instrument	Interest Rate	Maturity Date	2021	2020
City of La Crosse resource recovery bond	6.00 %	Nov. 1, 2021	$ —	$ 19
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	6.375	Sept. 1, 2038	200	200
First mortgage bonds	3.70	Oct. 1, 2042	100	100
First mortgage bonds	3.75	Dec. 1, 2047	100	100
First mortgage bonds	4.20	Sept. 1, 2048	200	200
First mortgage bonds [(b)]	3.05	May 1, 2051	100	100
First mortgage bonds [(a)]	2.82	May 1, 2051	100	—
Other long-term debt			1	—
Unamortized discount			(4)	(4)
Unamortized debt issuance cost			(10)	(9)
Current maturities			—	(19)
Total long-term debt			$ 987	$ 887

(a) 2021 financing.
(b) 2020 financing.

PSCo

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	2.25 %	Sept. 15, 2022	$ 300	$ 300
First mortgage bonds	2.50	March 15, 2023	250	250
First mortgage bonds	2.90	May 15, 2025	250	250
First mortgage bonds	3.70	June 15, 2028	350	350
First mortgage bonds [(b)]	1.90	Jan. 15, 2031	375	375
First mortgage bonds [(a)]	1.875	June 15, 2031	750	—
First mortgage bonds	6.25	Sept. 1, 2037	350	350
First mortgage bonds	6.50	Aug. 1, 2038	300	300
First mortgage bonds	4.75	Aug. 15, 2041	250	250
First mortgage bonds	3.60	Sept. 15, 2042	500	500
First mortgage bonds	3.95	March 15, 2043	250	250
First mortgage bonds	4.30	March 15, 2044	300	300
First mortgage bonds	3.55	June 15, 2046	250	250
First mortgage bonds	3.80	June 15, 2047	400	400
First mortgage bonds	4.10	June 15, 2048	350	350
First mortgage bonds	4.05	Sept. 15, 2049	400	400
First mortgage bonds	3.20	March 1, 2050	550	550
First mortgage bonds [(b)]	2.70	Jan. 15, 2051	375	375
Unamortized discount			(33)	(30)
Unamortized debt issuance cost			(50)	(46)
Current maturities			(300)	—
Total long-term debt			$ 6,167	$ 5,724

(a) 2021 financing.
(b) 2020 financing.

SPS

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	3.30 %	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds	4.40	Nov. 15, 2048	300	300
First mortgage bonds	3.75	June 15, 2049	300	300
First mortgage bonds [(b)]	3.15	May 1, 2050	350	350
First mortgage bonds [(a)]	3.15	May 1, 2050	250	—
Unamortized discount			(9)	(10)
Unamortized debt issuance cost			(28)	(26)
Total long-term debt			$ 3,013	$ 2,764

(a) 2020 financing re-opened in 2021.
(b) 2020 financing.

Other Subsidiaries

Financing Instrument	Interest Rate	Maturity Date	2021	2020
Various Eloigne affordable housing project notes	0.00% - 6.50%	2022 — 2055	$ 27	$ 27
Current maturities			(1)	(2)
Total long-term debt			$ 26	$ 25

Maturities of long-term debt:

(Millions of Dollars)	
2022	$ 601
2023	1,150
2024	552
2025	1,102
2026	501

Deferred Financing Costs — Deferred financing costs of approximately $184 million and $167 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2021 and 2020, respectively.

ATM Equity Offering — In November 2021, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $800 million of its common stock through an ATM program. As of Dec. 31, 2021, Xcel Energy Inc. had issued 5.33 million shares of common stock with net proceeds of $347 million through the ATM program.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2021 and 2020
Xcel Energy Inc.	7,000,000	$ 100	—
PSCo	10,000,000	0.01	—
SPS	10,000,000	1.00	—

Xcel Energy Inc. had the following common stock authorized/outstanding:

Common Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) as of Dec. 31, 2021	Common Stock Outstanding (Shares) as of Dec. 31, 2020
1,000,000,000	$ 2.50	544,025,269	537,438,394

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its utility subsidiaries to pay dividends. Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. Certain covenants also require Xcel Energy Inc. to be current on interest payments prior to dividend disbursements.

State regulatory commissions impose dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS, which are more restrictive than those imposed by the FERC. Requirements and actuals as of Dec. 31, 2021:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2021
NSP-Minnesota	47.2 %	57.6 %	52.9 %
NSP-Wisconsin	52.5	N/A	52.8
SPS [(a)]	45.0	55.0	54.5

(a) Excludes short-term debt.

(Amounts in Millions)	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1,558	$ 14,321	$ 15,332
NSP-Wisconsin [(a)]	11	2,091	N/A
SPS [(b)]	513	6,615	N/A

(a) Cannot pay annual dividends in excess of forecasted levels if its average equity-to-total capitalization ratio falls below the commission authorized level.
(b) May not pay a dividend that would cause a loss of its investment grade bond rating.

Issuance of securities by Xcel Energy Inc. is not generally subject to regulatory approval. However, utility financings and intra-system financings are subject to the jurisdiction of state regulatory commissions and/or the FERC. Xcel Energy may seek additional authorization as necessary.

Amounts authorized to issue as of Dec. 31, 2021:

(Millions of Dollars)	Long-Term Debt	Short-Term Debt
NSP-Minnesota	52.8% of total capitalization [(a)]	$ 2,300 [(a)]
NSP-Wisconsin	$ 150	150
SPS	—	600
PSCo	700 [(b)]	800

(a) NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization remains within the required range, and to issue short-term debt provided it does not exceed 15% of total capitalization.
(b) PSCo filed for additional long-term debt authorization in December 2021.

6. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. Xcel Energy's operating revenues consisted of the following:

	Year Ended Dec. 31, 2021			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,194	$ 1,222	$ 45	$ 4,461
C&I	5,050	640	30	5,720
Other	127	—	7	134
Total retail	8,371	1,862	82	10,315
Wholesale	1,540	—	—	1,540
Transmission	604	—	—	604
Other	61	148	—	209
Total revenue from contracts with customers	10,576	2,010	82	12,668
Alternative revenue and other	629	122	12	763
Total revenues	$ 11,205	$ 2,132	$ 94	$ 13,431

	Year Ended Dec. 31, 2020			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,066	$ 975	$ 42	$ 4,083
C&I	4,596	462	27	5,085
Other	125	—	6	131
Total retail	7,787	1,437	75	9,299
Wholesale	759	—	—	759
Transmission	579	—	—	579
Other	73	137	—	210
Total revenue from contracts with customers	9,198	1,574	75	10,847
Alternative revenue and other	604	62	13	679
Total revenues	$ 9,802	$ 1,636	$ 88	$ 11,526

	Year Ended Dec. 31, 2019			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,877	$ 1,127	$ 41	$ 4,045
C&I	4,844	567	29	5,440
Other	130	—	4	134
Total retail	7,851	1,694	74	9,619
Wholesale	737	—	—	737
Transmission	507	—	—	507
Other	49	120	—	169
Total revenue from contracts with customers	9,144	1,814	74	11,032
Alternative revenue and other	431	54	12	497
Total revenues	$ 9,575	$ 1,868	$ 86	$ 11,529

7. Income Taxes

Federal Loss Carryback Claims - In 2020, Xcel Energy identified certain expense related to tax years 2009 - 2011 that qualify for an extended carryback claim. As a result, a tax benefit of approximately $13 million was recognized in 2020.

Federal Audit — Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2014 - 2016	December 2022
2018	September 2022

Additionally, the statute of limitations related to the federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to the additional federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions and various other state income-based tax returns.

As of Dec. 31, 2021, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Year
Colorado	2014
Minnesota	2014
Texas	2016
Wisconsin	2016

- In April 2021, Texas began an audit of tax years 2016-2019. As of Dec. 31, 2021, no material adjustments have been proposed.
- In March 2021, Wisconsin began an audit of tax years 2016 - 2019. As of Dec. 31, 2021, no material adjustments have been proposed.
- In July 2020, Minnesota began an audit of tax years 2015 - 2018. As of Dec. 31, 2021, no material adjustments have been proposed.
- No other state income tax audits in progress for its major operating jurisdictions as of Dec. 31, 2021.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits - permanent vs. temporary:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	$ 47	$ 41
Unrecognized tax benefit — Temporary tax positions	11	11
Total unrecognized tax benefit	$ 58	$ 52

Changes in unrecognized tax benefits:

(Millions of Dollars)	2021	2020	2019
Balance at Jan. 1	$ 52	$ 44	$ 37
Additions based on tax positions related to the current year	5	9	10
Reductions based on tax positions related to the current year	—	(2)	(4)
Additions for tax positions of prior years	2	35	1
Reductions for tax positions of prior years	(1)	(34)	—
Balance at Dec. 31	$ 58	$ 52	$ 44

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	$ (36)	$ (31)

As the IRS progresses its review of the tax loss carryback claims and as state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $28 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2021	2020	2019
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (3)	$ —	$ —
Interest expense related to unrecognized tax benefits	—	(3)	—
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (3)	$ (3)	$ —

No penalties were accrued related to unrecognized tax benefits as of Dec. 31, 2021, 2020 or 2019.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31:

(Millions of Dollars)	2021	2020
Federal NOL carryforward	$ 765	$ —
Federal tax credit carryforwards	1,172	791
State NOL carryforwards	1,648	839
Valuation allowances for state NOL carryforwards	(3)	(4)
State tax credit carryforwards, net of federal detriment [(a)]	89	89
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(64)	(64)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2021 and 2020.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $17 million as of Dec. 31, 2021 and 2020.

Federal carryforward periods expire between 2031 and 2041 and state carryforward periods expire starting 2022.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2021	2020	2019
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	5.0	4.9	4.9
(Decreases) increases in tax from:			
Wind PTCs	(23.4)	(15.7)	(9.4)
Plant regulatory differences [(a)]	(6.2)	(7.6)	(5.8)
Other tax credits, net NOL & tax credit allowances	(1.1)	(1.2)	(1.7)
NOL Carryback	—	(0.9)	—
Change in unrecognized tax benefits	0.4	0.5	0.5
Other, net	(0.3)	(1.4)	(1.0)
Effective income tax rate	(4.6)%	(0.4)%	8.5 %

(a) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions and additional prepaid pension asset amortization.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2021	2020	2019
Current federal tax expense (benefit)	$ 15	$ (13)	$ (16)
Current state tax (benefit) expense	(2)	2	4
Current change in unrecognized tax expense	1	18	2
Deferred federal tax (benefit) expense	(183)	(89)	55
Deferred state tax expense	99	91	83
Deferred change in unrecognized tax expense (benefit)	5	(10)	5
Deferred ITCs	(5)	(5)	(5)
Total income tax (benefit) expense	$ (70)	$ (6)	$ 128

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2021	2020	2019
Deferred tax expense excluding items below	$ 148	$ 237	$ 344
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(221)	(247)	(206)
Tax (benefit) expense allocated to other comprehensive income, adoption of ASC Topic 326, and other	(6)	2	5
Deferred tax (benefit) expense	$ (79)	$ (8)	$ 143

Components of net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2021	2020 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 6,231	$ 5,810
Operating lease assets	351	400
Regulatory assets	598	603
Deferred fuel costs	262	(6)
Pension expense	175	176
Other	93	74
Total deferred tax liabilities	$ 7,710	$ 7,057
Deferred tax assets:		
Regulatory liabilities	$ 780	$ 806
Operating lease liabilities	351	400
Tax credit carryforward	1,261	880
NOL carryforward	247	37
NOL and tax credit valuation allowances	(64)	(64)
Other employee benefits	119	141
Deferred ITCs	15	13
Other	107	98
Total deferred tax assets	$ 2,816	$ 2,311
Net deferred tax liability	$ 4,894	$ 4,746

(a) Prior periods have been reclassified to conform to current year presentation.

8. Share-Based Compensation

Incentive Plan Including Share-Based Compensation — Xcel Energy has an incentive plan which includes share-based payment elements, the Amended and Restated 2015 Omnibus Incentive Plan with 7.0 million equity shares authorized.

Restricted Stock — The Amended and Restated 2015 Omnibus Incentive Plan allows certain employees to elect to receive shares of common or restricted stock. Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Restricted stock has a fair value equal to the market trading price of Xcel Energy stock at the grant date.

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2021	2020	2019
Granted shares	2	1	13
Grant date fair value	$ 61.54	$ 70.26	$ 53.46

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2021	15	$ 56.68
Granted	2	61.54
Forfeited	—	70.26
Vested	(9)	49.71
Dividend equivalents	—	66.73
Nonvested restricted stock at Dec. 31, 2021	8	67.26

Other Equity Awards — Xcel Energy's Board of Directors has granted equity awards under the Amended and Restated 2015 Omnibus Incentive Plan, which includes various vesting conditions and performance goals. At the end of the restricted period, such grants will be awarded if vesting conditions and/or performance goals are met.

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. A total of 0.2 million, 0.2 million, and 0.3 million time-based equity shares subject only to service conditions were granted annually in 2021, 2020 and 2019, respectively.

The performance conditions for a portion of the awards granted from 2019 to 2021 are based on relative TSR and environmental goals. Equity awards with performance conditions will be settled or forfeited after three years, with payouts ranging from zero to 200% depending on achievement.

Equity award units granted to employees (excluding restricted stock):

(Units in Thousands)	2021	2020	2019
Granted units	421	411	483
Weighted average grant date fair value	$ 66.03	$ 62.92	$ 49.67

Equity awards vested:

(Units in Thousands, Fair Value in Millions)	2021	2020	2019
Vested Units	392	442	464
Total Fair Value	$ 27	$ 29	$ 29

Changes in the nonvested portion of equity award units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2021	780	$ 55.68
Granted	421	66.03
Forfeited	(146)	61.76
Vested	(392)	48.91
Dividend equivalents	32	58.00
Nonvested Units at Dec. 31, 2021	695	64.59

Stock Equivalent Units — Non-employee members of Xcel Energy's Board of Directors may elect to receive their annual equity grant as stock equivalent units in lieu of common stock. Each unit's value is equal to one share of common stock. The annual equity grant is vested as of the date of each member's election to the Board of Directors; there is no further service or other condition. Directors may also elect to receive their cash fees as stock equivalent units in lieu of cash. Stock equivalent units are payable as a distribution of common stock upon a director's termination of service.

Stock equivalent units granted:

(Units in Thousands)	2021	2020	2019
Granted units	31	33	29
Weighted average grant date fair value	$ 68.15	$ 61.61	$ 58.44

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2021	630	$ 36.28
Granted	31	68.15
Units distributed	(73)	31.47
Dividend equivalents	16	66.98
Stock equivalent units at Dec. 31, 2021	604	39.27

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Amended and Restated 2015 Omnibus Incentive Plan. This plan allows Xcel Energy to attach various performance goals to the awards granted. The liability awards have been historically dependent on relative TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to a peer group of other utility companies. Potential payouts of the awards range from zero to 200%.

TSR liability awards granted:

(In Thousands)	2021	2020	2019
Awards granted	221	212	225

TSR liability awards settled:

(Units In Thousands, Settlement Amount in Millions)	2021	2020	2019
Awards settled	446	476	466
Settlement amount (cash, common stock and deferred amounts)	$ 27	$ 33	$ 25

TSR liability awards of $22 million were settled in cash in 2021.

Share-Based Compensation Expense — Other than for restricted stock, vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target. Additionally, approximately 0.2 million, 0.2 million, and 0.3 million of equity award units were granted in 2021, 2020, and 2019, respectively, with vesting subject only to service conditions of three years.

Generally, these instruments are considered to be equity awards as the award settlement determination (shares or cash) is made by Xcel Energy, not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement.

Grant date fair value of equity awards is expensed over the service period. TSR liability awards have been historically settled partially in cash, and do not qualify as equity awards, but rather are accounted for as liabilities. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the shares on the date the award is settled.

Compensation costs related to share-based awards:

(Millions of Dollars)	2021	2020	2019
Compensation cost for share-based awards [(a)]	$ 31	$ 73	$ 58
Tax benefit recognized in income	8	19	15

(a) Compensation costs for share-based payments are included in O&M expense.

There was approximately $28 million in 2021 and $51 million in 2020 of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the unrecognized amount over a weighted average period of 1.6 years.

9. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the weighted average number of common shares outstanding. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding.

Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. has common stock equivalents related to forward equity agreements and certain equity awards in share-based compensation arrangements. Common stock equivalents include commitments to issue common stock related to time-based equity compensation awards.

Stock equivalent units granted to Xcel Energy's Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these. Restricted stock issued to employees under the Executive Annual Incentive Award Plan is included in common shares outstanding when granted.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

Common shares outstanding used in the basic and diluted EPS computation:

(Shares in Millions)	2021	2020	2019
Basic	539	527	519
Diluted [(a)]	540	528	520

(a) Diluted common shares outstanding included common stock equivalents of 0.3 million, 1.1 million and 1.3 million shares for 2021, 2020 and 2019, respectively.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled fund investments may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third-party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the consolidated financial statements.

Non-Derivative Fair Value Measurements

Nuclear Decommissioning Fund

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the MPUC approved asset allocation for the investment targets by asset class for the qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $1.3 billion and $981 million as of Dec. 31, 2021 and 2020, respectively, and unrealized losses were $7 million and $5 million as of Dec. 31, 2021 and 2020, respectively.

Non-derivative instruments with recurring fair value measurements:

	Dec. 31, 2021					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 64	$ 64	$ —	$ —	$ —	$ 64
Commingled funds	856	—	—	—	1,294	1,294
Debt securities	631	—	666	9	—	675
Equity securities	411	1,222	1	—	—	1,223
Total	$ 1,962	$ 1,286	$ 667	$ 9	$ 1,294	$ 3,256

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $208 million of equity investments in unconsolidated subsidiaries and $164 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2020					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 40	$ 40	$ —	$ —	$ —	$ 40
Commingled funds	787	—	—	—	1,041	1,041
Debt securities	528	—	572	13	—	585
Equity securities	446	1,109	2	—	—	1,111
Total	$ 1,801	$ 1,149	$ 574	$ 13	$ 1,041	$ 2,777

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $165 million of equity investments in unconsolidated subsidiaries and $154 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2021 and 2020, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2021:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 years	Total
Debt securities	$ 4	$ 149	$ 208	$ 314	$ 675

Rabbi Trusts

Xcel Energy has established rabbi trusts to provide partial funding for future distributions of its SERP and deferred compensation plan.

Cost and fair value of assets held in rabbi trusts:

	Dec. 31, 2021				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 20	$ 20	$ —	$ —	$ 20
Mutual funds	75	89	—	—	89
Total	$ 95	$ 109	$ —	$ —	$ 109

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

	Dec. 31, 2020				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 32	$ 32	$ —	$ —	$ 32
Mutual funds	60	70	—	—	70
Total	$ 92	$ 102	$ —	$ —	$ 102

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes, with changes in fair value prior to settlement recorded as other comprehensive income.

As of Dec. 31, 2021, accumulated other comprehensive loss related to settled interest rate derivatives included $5 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2021, Xcel Energy had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but may not be designated as qualifying hedging transactions. The classification of unrealized losses or gains on these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms.

As of Dec. 31, 2021, Xcel Energy had no commodity contracts designated as cash flow hedges.

Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [(a)(b)]	Dec. 31, 2021	Dec. 31, 2020
MWh of electricity	80	87
MMBtu of natural gas	156	175

(a) Not reflective of net positions in the underlying commodities.

(b) Notional amounts for options included on a gross basis but weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the consolidated balance sheets.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2021, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $83 million or 38% of this credit exposure, had investment grade credit ratings from S&P, Moody's Investor Services or Fitch Ratings. Three of the 10 most significant counterparties, comprising $44 million or 20% of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $38 million or 18% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income:

(Millions of Dollars)	2021	2020	2019
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (85)	$ (80)	$ (60)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	4	(10)	(23)
After-tax net realized losses on derivative transactions reclassified into earnings	6	5	3
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (75)	$ (85)	$ (80)

Impact of derivative activity:

	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2021		
Derivatives designated as cash flow hedges		
Interest rate	$ 5	$ —
Total	$ 5	$ —
Other derivative instruments		
Electric commodity	$ —	$ 32
Natural gas commodity	—	(4)
Total	$ —	$ 28
Year Ended Dec. 31, 2020		
Interest rate	$ (13)	$ —
Total	$ (13)	$ —
Other derivative instruments		
Electric commodity	$ —	$ (5)
Natural gas commodity	—	(13)
Total	$ —	$ (18)
Year Ended Dec. 31, 2019		
Interest rate	$ (30)	$ —
Total	$ (30)	$ —
Other derivative instruments		
Electric commodity	$ —	$ 8
Natural gas commodity	—	(9)
Total	$ —	$ (1)

	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2021			
Derivatives designated as cash flow hedges			
Interest rate	$ 8 [(a)]	$ —	$ —
Total	$ 8	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 63 [(b)]
Electric commodity	—	(23) [(c)]	—
Natural gas commodity	—	5 [(d)]	(22) [(d)]
Total	$ —	$ (18)	$ 41
Year Ended Dec. 31, 2020			
Derivatives designated as cash flow hedges			
Interest rate	$ 7 [(a)]	$ —	$ —
Total	$ 7	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (1) [(b)]
Electric commodity	—	(3) [(c)]	—
Natural gas commodity	—	10 [(d)]	(13) [(d)]
Total	$ —	$ 7	$ (14)
Year Ended Dec. 31, 2019			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 [(a)]	$ —	$ —
Total	$ 4	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 2 [(b)]
Electric commodity	—	(5) [(c)]	—
Natural gas commodity	—	2 [(d)]	(7) [(d)]
Total	$ —	$ (3)	$ (5)

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Settlement losses related to natural gas operations are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2021, 2020 and 2019.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase and normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. As of Dec. 31, 2021 and 2020, there were $3 million and $4 million of derivative instruments in a liability position with such underlying contract provisions, respectively. Certain contracts also contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under the other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2021 and 2020, there were approximately $64 million and $60 million of derivative instruments in a liability position with such underlying contract provisions, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. Provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2021 and 2020.

Recurring Fair Value Measurements — Derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 22	$ 137	$ 21	$ 180	$ (134)	$ 46	$ 2	$ 67	$ 1	$ 70	$ (52)	$ 18
Electric commodity	—	—	57	57	(1)	56	—	—	20	20	(1)	19
Natural gas commodity	—	18	—	18	—	18	—	9	—	9	—	9
Total current derivative assets	$ 22	$ 155	$ 78	$ 255	$ (135)	120	$ 2	$ 76	$ 21	$ 99	$ (53)	46
PPAs (b)						3						3
Current derivative instruments						$ 123						$ 49
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 16	$ 63	$ 89	$ 168	$ (107)	$ 61	$ 8	$ 66	$ 8	$ 82	$ (62)	$ 20
Total noncurrent derivative assets	$ 16	$ 63	$ 89	$ 168	$ (107)	61	$ 8	$ 66	$ 8	$ 82	$ (62)	20
PPAs (b)						6						10
Noncurrent derivative instruments						$ 67						$ 30

	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 19	$ 148	$ 20	$ 187	$ (143)	$ 44	$ 4	$ 64	$ 17	$ 85	$ (58)	$ 27
Electric commodity	—	—	1	1	(1)	—	—	—	1	1	(1)	—
Natural gas commodity	—	8	—	8	—	8	—	9	—	9	—	9
Total current derivative liabilities	$ 19	$ 156	$ 21	$ 196	$ (144)	52	$ 4	$ 73	$ 18	$ 95	$ (59)	36
PPAs (b)						17						17
Current derivative instruments						$ 69						$ 53
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 18	$ 48	$ 127	$ 193	$ (128)	$ 65	$ 3	$ 58	$ 60	$ 121	$ (47)	$ 74
Total noncurrent derivative liabilities	$ 18	$ 48	$ 127	$ 193	$ (128)	65	$ 3	$ 58	$ 60	$ 121	$ (47)	74
PPAs (b)						40						57
Noncurrent derivative instruments						$ 105						$ 131

(a) Xcel Energy nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement and all derivative instruments and related collateral amounts were subject to master netting agreements as of Dec. 31, 2021 and 2020. At Dec. 31, 2021, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2020, derivative assets and liabilities include $15 million of obligations to return cash collateral. At Dec. 31, 2021 and 2020, derivative assets and liabilities include rights to reclaim cash collateral of $30 million and $6 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, contracts are no longer adjusted to fair value and the previous carrying value of these contracts is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

	Year Ended Dec. 31		
(Millions of Dollars)	2021	2020	2019
Balance at Jan. 1	$ (49)	$ 4	$ 29
Purchases	65	51	44
Settlements	(158)	(73)	(64)
Net transactions recorded during the period:			
Gains (losses) recognized in earnings [(a)]	49	(39)	(8)
Net gains recognized as regulatory assets and liabilities	112	8	3
Balance at Dec. 31	$ 19	$ (49)	$ 4

(a) Level 3 losses recognized in earnings are subject to offsetting gains of derivative instruments categorized as levels 1 and 2 in the income statement.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for Dec. 31, 2021, 2020 and 2019.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2021		2020	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 22,380	$ 25,232	$ 20,066	$ 24,412

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2021 and 2020, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

11. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits. The average annual interest crediting rates for these plans was 2.03, 1.89 and 2.82% in 2021, 2020, and 2019, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants.

The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows.

Obligations of the SERP and nonqualified plan as of Dec. 31, 2021 and 2020 were $43 million and $43 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2021 and $6 million in 2020.

Xcel Energy's investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as long-term projected return levels.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2021 were above the assumed level of 6.49%.
- Investment returns in 2020 were above the assumed level of 6.87%.
- Investment returns in 2019 were above the assumed level of 6.87%.
- In 2022, expected investment-return assumption is 6.49%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations consider many factors and generally result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

	Dec. 31, 2021 [(a)]					Dec. 31, 2020 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 133	$ —	$ —	$ —	$ 133	$ 209	$ —	$ —	$ —	$ 209
Commingled funds	1,324	—	—	1,143	2,467	1,462	—	—	1,115	2,577
Debt securities	—	959	5	—	964	—	714	4	—	718
Equity securities	67	—	—	—	67	77	—	—	—	77
Other	—	7	—	32	39	13	5	—	—	18
Total	$ 1,524	$ 966	$ 5	$ 1,175	$ 3,670	$ 1,761	$ 719	$ 4	$ 1,115	$ 3,599

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

For each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2021 [(a)]					Dec. 31, 2020 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 28	$ —	$ —	$ —	$ 28	$ 27	$ —	$ —	$ —	$ 27
Insurance contracts	—	52	—	—	52	—	50	—	—	50
Commingled funds	64	—	—	77	141	72	—	—	69	141
Debt securities	—	218	1	—	219	—	232	—	—	232
Other	—	2	—	—	2	—	2	—	—	2
Total	$ 92	$ 272	$ 1	$ 77	$ 442	$ 99	$ 284	$ —	$ 69	$ 452

(a) See Note 10 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2021 or 2020.

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2020 to Dec. 31, 2021, due primarily to benefit payments and increases in discount rates used in actuarial valuations. Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for Xcel Energy are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2021	2020	2021	2020
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,964	$ 3,701	$ 574	$ 547
Service cost	104	95	2	1
Interest cost	104	125	15	18
Plan amendments	5	—	—	—
Actuarial (gain) loss	(94)	328	(41)	50
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	2	1
Benefit payments [(a)]	(365)	(285)	(49)	(51)
Obligation at Dec. 31	$ 3,718	$ 3,964	$ 511	$ 574
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 3,599	$ 3,184	$ 452	$ 449
Actual return on plan assets	305	550	16	35
Employer contributions	131	150	15	11
Plan participants' contributions	—	—	8	8
Benefit payments	(365)	(285)	(49)	(51)
Fair value of plan assets at Dec. 31	$ 3,670	$ 3,599	$ 442	$ 452
Funded status of plans at Dec. 31	$ (48)	$ (365)	$ (69)	$ (122)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Noncurrent assets	$ 19	$ —	$ 33	$ 6
Current liabilities	—	—	(4)	(7)
Noncurrent liabilities	(67)	(365)	(98)	(121)
Net amounts recognized	$ (48)	$ (365)	$ (69)	$ (122)

(a) Includes approximately $197 million in 2021 and $0 million in 2020 of lump-sum benefit payments used in the determination of a settlement charge.

Significant Assumptions Used to Measure Benefit Obligations:	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate for year-end valuation	3.08 %	2.71 %	3.09 %	2.65 %
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	5.30 %	5.50 %
Health care costs trend rate — initial: Post-65	N/A	N/A	4.90 %	5.00 %
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50 %	4.50 %
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50 %	4.50 %
Years until ultimate trend is reached	N/A	N/A	4	5

Accumulated benefit obligation for the pension plan was $3,469 million and $3,693 million as of Dec. 31, 2021 and 2020, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income (expense) in the consolidated statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

(Millions of Dollars)	Pension Benefits 2021	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2021	Postretirement Benefits 2020	Postretirement Benefits 2019
Service cost	$ 104	$ 95	$ 86	$ 2	$ 1	$ 2
Interest cost	104	125	145	15	18	22
Expected return on plan assets	(206)	(208)	(203)	(18)	(19)	(21)
Amortization of prior service credit	(1)	(4)	(5)	(8)	(8)	(10)
Amortization of net loss	107	100	87	5	4	5
Settlement charge [(a)]	59	—	6	—	—	—
Net periodic pension cost (credit)	167	108	116	(4)	(4)	(2)
Effects of regulation	(46)	9	(1)	2	3	1
Net benefit cost (credit) recognized for financial reporting	$ 121	$ 117	$ 115	$ (2)	$ (1)	$ (1)
Significant Assumptions Used to Measure Costs:						
Discount rate	2.71 %	3.49 %	4.31 %	2.65 %	3.47 %	4.32 %
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	6.49	6.87	6.87	4.10	4.50	4.50

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2021 and 2019, as a result of lump-sum distributions during each plan year, Xcel Energy recorded a total pension settlement charge of $59 million and $6 million, respectively, the majority of which was not recognized due to the effects of regulation. A total of $7 million and $1 million was recorded in the consolidated statements of income in 2021 and 2019, respectively. There were no settlement charges recorded for the qualified pension plans in 2020.

(Millions of Dollars)	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 978	$ 1,333	$ 81	$ 126
Prior service credit	(9)	(11)	(7)	(15)
Total	$ 969	$ 1,322	$ 74	$ 111
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 74	$ 82	$ —	$ —
Noncurrent regulatory assets	846	1,181	90	125
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(19)	(18)
Deferred income taxes	13	15	1	1
Net-of-tax accumulated other comprehensive income	36	44	3	4
Total	$ 969	$ 1,322	$ 74	$ 111
Measurement date	Dec. 31, 2021	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2020

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2019 - 2022 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $50 million in January 2022.
- $131 million in 2021.
- $150 million in 2020.
- $154 million in 2019.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities.

Voluntary postretirement funding contributions:

- Expects to contribute approximately $9 million during 2022.
- $15 million during 2021.
- $11 million during 2020.
- $15 million during 2019.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Domestic and international equity securities	33 %	35 %	15 %	15 %
Long-duration fixed income securities	37	35	—	—
Short-to-intermediate fixed income securities	11	13	71	72
Alternative investments	17	15	8	9
Cash	2	2	6	4
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year.

Plan Amendments —

In 2019, the Pension Protection Act measurement concept was extended beyond 2019 for NSP bargaining terminations and retirements to Dec. 31, 2022.

There were no significant plan amendments made in 2020 which affected the postretirement benefit obligation.

In 2021, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

Projected Benefit Payments

Xcel Energy's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2022	$ 323	$ 42	$ 2	$ 40
2023	257	41	2	39
2024	253	40	2	38
2025	251	38	2	36
2026	245	37	2	35
2027-2031	1,156	165	13	152

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $43 million in 2021, $42 million in 2020 and $39 million in 2019.

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans.

Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

12. Commitments and Contingencies

Legal

Xcel Energy is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's consolidated financial statements. Legal fees are generally expensed as incurred.

Gas Trading Litigation — e prime is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing but has not engaged in natural gas trading or marketing activities since 2003. Multiple lawsuits involving multiple plaintiffs seeking monetary damages were commenced against e prime and its affiliates, including Xcel Energy, between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Cases were all consolidated in the U.S. District Court in Nevada.

One case remains active which includes a multi-district litigation matter consisting of a Wisconsin purported class (Arandell Corp.).

Arandell Corp. — The trial has been vacated and will be rescheduled after the court rules on the pending motions for reconsideration and for class certification. Xcel Energy has concluded that a loss is remote for the remaining lawsuit.

Breckenridge/Colorado — In February 2019, the MDL panel remanded Breckenridge back to the U.S. District Court in Colorado. Settlement of approximately $3 million was reached in February 2021. In July 2021, the settlement was approved.

Rate Matters and Other

Xcel Energy's operating subsidiaries are involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the consolidated financial statements.

Minnesota Winter Storm Uri Costs — In its Minnesota jurisdiction, NSP-Minnesota is participating in a contested case regarding the prudency of incremental natural gas costs incurred during Winter Storm Uri. Other parties to the case have recommended significant cost disallowances, and while ultimate resolution of the matter is uncertain, it is reasonably possible that the MPUC could disallow certain deferred costs, resulting in earnings losses. The OAG recommended the MPUC deny recovery of up to $179 million, the largest recommendation among the intervenor positions.

NSP-Minnesota strongly disagrees with the recommendations of the DOC, OAG and CUB, and believes that it acted prudently and according to MPUC approved procedures for the best interest of its customers and stakeholders.

NSP-Minnesota filed rebuttal testimony in January 2022 detailing its position that the disallowances recommended by other parties lack any merit in the prudency review given the pertinent facts regarding NSP-Minnesota's actions before, during and after the storm event. An MPUC decision is expected in the summer of 2022.

Sherco — In 2018, NSP-Minnesota and Southern Minnesota Municipal Power Agency (Co-owner of Sherco Unit 3) reached a settlement with GE related to a 2011 incident, which damaged the turbine at Sherco Unit 3 and resulted in an extended outage for repair. NSP-Minnesota notified the MPUC of its proposal to refund settlement proceeds to customers through the FCA.

In March 2019, the MPUC approved NSP-Minnesota's settlement refund proposal. Additionally, the MPUC decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of an appeal pending between GE and NSP-Minnesota's insurers. In February 2020, the Minnesota Court of Appeals affirmed the district court's judgment in favor of GE. In March 2020, NSP-Minnesota's insurers filed a petition seeking additional review by the Minnesota Supreme Court.

In April 2020, the Minnesota Supreme Court denied the insurers' petition for further review, ending the litigation.

In January 2021, the OAG and DOC recommended that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the FCA. NSP-Minnesota subsequently filed its response, asserting that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed $22 million of related costs and no additional refund or disallowance is appropriate. A final decision by the MPUC is pending. A loss related to this matter is deemed remote.

Westmoreland Arbitration — In November 2014, insurers of the Westmoreland Coal Company filed an arbitration demand against NSP-Minnesota, Southern Minnesota Municipal Power Agency and Western Fuels Association, seeking recovery of alleged $36 million of business losses due to a turbine failure at Sherco Unit 3. The Westmoreland insurers claim NSP-Minnesota's invocation of the force majeure clause to stop the supply of coal was improper because the incident was allegedly caused by NSP-Minnesota's failure to conform to industry maintenance standards.

NSP-Minnesota denies the claims asserted by the Westmoreland insurers and believes it properly stopped the supply of coal based upon the force majeure provision. A final hearing has been scheduled for October 2022. The parties are also required to participate in mediation, which has been scheduled for the first quarter of 2022. At this stage of the proceeding, a reasonable estimate of damages or range of damages cannot be determined.

MISO ROE Complaints — In November 2013 and February 2015, customer groups filed two ROE complaints against MISO TOs, which includes NSP-Minnesota and NSP-Wisconsin. The first complaint requested a reduction in base ROE transmission formula rates from 12.38% to 9.15% for the time period of Nov. 12, 2013 to Feb. 11, 2015, and removal of ROE adders (including those for RTO membership). The second complaint requested, for a subsequent time period, a base ROE reduction from 12.38% to 8.67%.

In September 2016, the FERC issued an order (Opinion No. 551) granting a 10.32% base ROE effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C Circuit subsequently vacated and remanded Opinion No. 551.

In November 2019, the FERC issued an order (Opinion No. 569), which set the MISO base ROE at 9.88%, effective Sept. 28, 2016 and for the first complaint period. The FERC also dismissed the second complaint. In December 2019, MISO TOs filed a request for rehearing regarding the new ROE methodology announced in Opinion No. 569. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds.

In May 2020, the FERC issued an order (Opinion No. 569-A) which granted rehearing in part to Opinion 569 and further refined the FERC's ROE methodology, most significantly to incorporate the risk premium model (in addition to the discounted cash flow and capital asset pricing models), resulting in a new base ROE of 10.02%, effective Sept. 28, 2016 and for the first complaint period. The FERC also affirmed its decision in Opinion No. 569 to dismiss the second complaint.

In November 2020, the FERC issued an order (Opinion No. 569-B) in response to rehearing requests. The FERC corrected certain inputs to its ROE calculation model, did not change the ROE effective Sept. 28, 2016, and for the first MISO complaint period and upheld its decision to deny refunds for the second complaint period. NSP-Minnesota has recognized a liability for its best estimate of final refunds to customers. Each 10 basis point reduction in ROE for the first complaint period, second complaint period and subsequent period relative to amounts accrued would reduce Xcel Energy's net income by $1 million, $1 million and $2 million, respectively.

The MISO TOs and various parties have filed petitions for review of Opinion Nos. 569, 569-A and 569-B at the D.C. Circuit. Oral arguments were held in late 2021 and a decision is expected by the end of the third quarter of 2022.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates. The timing of these refunds is uncertain.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. FERC has asked that this appeal be stayed until early 2022, in order to provide FERC with time to issue an order on SPS' April 2018 rehearing request. FERC's order is expected in the first quarter of 2022. The D.C. Circuit appeal may resume after that FERC order is issued.

Wind Operating Commitments — PUCT and NMPRC orders related to the Hale and Sagamore wind projects included certain operating and savings minimums. In general, annual generation must exceed a net capacity factor of 48%. If annual generation is below the guaranteed level, SPS would be obligated to refund an amount equal to foregone PTCs and fuel savings. Additionally, retail customer savings must exceed project costs included in base rates over the first ten years of operations. SPS would be required to refund excess costs, if any, after ten years of operations. As of Dec. 31, 2021, the full-year net capacity factor was 48.4%, resulting in no refund liability for 2021.

Contract Termination — SPS and LP&L are parties to a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the Electric Reliability Council of Texas (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million (lump sum or annual installments), to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The settlement agreement is subject to approval by the PUCT and FERC.

Comanche Unit 3 Litigation — In February 2021, the joint owners of Comanche Unit 3 (CORE Electric Cooperative, formerly known as Intermountain Rural Electrical Association, and Holy Cross Electric) served PSCo with a notice of claim related to Comanche Unit 3's operation and availability.

In September 2021, CORE Electric Cooperative filed a lawsuit in Colorado state court seeking an unspecified amount of damages. CORE Electric Cooperative alleges PSCo breached ownership agreement terms by failing to operate Comanche Unit 3 in accordance with prudent utility practices. PSCo filed a Motion to Dismiss several of CORE's claims. In January 2022 the Court granted PSCo's Motion to Dismiss CORE's claim for damages for replacement power costs, claims for unjust enrichment and declaratory judgment. CORE's claims for breach of contract, breach of the duty of good faith and fair dealing, and waste remain pending.

In November 2021, PSCo resolved all differences with Holy Cross Electric related to their claim.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process.

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination.

Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to have sent wastes to that site.

Historical MGP, Landfill and Disposal Sites

Xcel Energy is currently investigating, remediating or performing post-closure actions at 16 historical MGP, landfill or other disposal sites across its service territories, excluding sites that are being addressed under current coal ash regulations (see below).

Xcel Energy has recognized its best estimate of costs/liabilities from final resolution of these issues; however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state regulations that impose requirements for handling, storage, treatment and disposal of solid waste. Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Currently, Xcel Energy has eight regulated ash units in operation.

Xcel Energy is conducting groundwater sampling and monitoring and implementing assessment of corrective measures at certain CCR landfills and surface impoundments. In NSP-Minnesota, no results above the groundwater protection standards in the rule were identified. In PSCo, increases above background concentrations were detected at four locations. Based on further assessments, PSCo is evaluating options for corrective action at two locations, one of which indicates potential offsite impacts to groundwater. The total cost is uncertain, but could be up to $35 million. PSCo is continuing to assess the financial and regulatory impacts.

In August 2020, the EPA published its final rule to implement closure by April 2021 for all CCR impoundments affected by the August 2018 D.C. Circuit ruling. This final rule required Xcel Energy to expedite closure plans for two impoundments.

In October 2020, NSP-Minnesota completed construction and placed in service a new impoundment to replace the clay lined impoundment. With the new ash pond in service, NSP-Minnesota has initiated closure activities for the existing ash pond at an estimated cost of $4 million. NSP-Minnesota has five years to complete closure activities.

PSCo also built an alternative collection and treatment system to remove the Comanche Station bottom ash pond from service. The total cost of the alternate treatment system is approximately $25 million. PSCo worked expeditiously to meet the April 11, 2021 deadline, but was not able to remove the pond from service until June 18, 2021. PSCo expects to negotiate a compliance order with the EPA addressing the closure deadline as well as other potential issues. PSCo will also now proceed with closure of the pond, at an estimated cost of $3 million.

Closure costs for existing impoundments are included in the calculation of the ARO.

Federal CWA Waters of the U.S. Rule — Xcel Energy is monitoring ongoing changes to the definition of Waters of the U.S. under the CWA. Regardless of which definition is applicable in the states in which we operate, Xcel Energy does not anticipate that compliance costs will be material.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In October 2020, the EPA published a final rule revising the regulations.

The retirement of units affected by the final ELG rule is subject to regulatory approval. The exact total cost of ELG compliance is therefore uncertain but Xcel Energy does not anticipate that compliance costs will be material.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates the likely future cost for complying with impingement and entrainment requirements is approximately $39 million, to be incurred between 2022 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to $192 million. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. The regional haze first planning period requirements developed by Minnesota and Colorado were approved by the EPA in 2012 and implemented by 2014 and 2016, respectively. Texas' first regional haze plan has undergone federal review.

All states are now subject to a second round of regional haze planning/rulemaking, focusing on additional reductions to meet reasonable progress requirements. Any additional impacts to Xcel Energy facilities are expected to be minimal.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the D.C. Circuit that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking. The EPA reaffirmed the rule in August 2020 with minor changes.

The 2020 EPA Action has been challenged. All pending actions could be consolidated and may proceed in the Fifth Circuit or the D.C. Circuit, where a parallel challenge has been filed. The timing of final decisions is unclear.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule referenced above are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule.

Implementation of the NAAQS for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with one exception. The EPA issued final designations, which found the area near the SPS Harrington plant as "unclassifiable." The area near the Harrington plant was monitored for the three years ending in 2019 and the monitoring showed the area to be exceeding the standard.

To address this issue, 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.

Xcel Energy believes compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for Xcel Energy's assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning was $3.3 billion and $2.8 billion for 2021 and 2020, respectively.

Xcel Energy's AROs were as follows:

(Millions of Dollars)	Jan. 1, 2021	Amounts Incurred (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2021 (c)
Electric					
Nuclear	$ 1,957	$ —	$ 99	$ —	$ 2,056
Wind	360	101	17	—	478
Steam, hydro and other production	264	6	10	8	288
Distribution	46	—	1	—	47
Natural gas					
Transmission and distribution	252	—	10	9	271
Miscellaneous	3	—	—	5	8
Common					
Miscellaneous	1	—	—	—	1
Non-utility					
Miscellaneous	1	—	1	—	2
Total liability	$ 2,884	$ 107	$ 138	$ 22	$ 3,151

(a) Amounts incurred related to the wind farms placed in service in 2021 for NSP-Minnesota (Blazing Star 2, Mower and Freeborn) and removal of a utility scale battery asset in NSP-Minnesota.

(b) In 2021, AROs were revised for changes in timing and estimates of cash flows. Revisions in steam, hydro and other production AROs were primarily related to changes in cost estimates for remediation of ash containment facilities. Changes in gas transmission and distribution AROs were primarily related to changes in labor rates coupled with increased gas line mileage and number of services.

(c) There were no ARO amounts settled in 2021.

(Millions of Dollars)	Jan. 1, 2020	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2020
Electric						
Nuclear	$2,068	$ —	$ —	$ 105	$ (216)	$ 1,957
Steam, hydro and other production	202	—	(5)	9	58	264
Wind	146	149	(3)	8	60	360
Distribution	44	—	—	2	—	46
Natural gas						
Transmission and distribution	236	—	—	10	6	252
Miscellaneous	3	—	—	—	—	3
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,701	$ 149	$ (8)	$ 134	$ (92)	$ 2,884

(a) Amounts incurred related to the wind farms placed in service in 2020 for NSP-Minnesota (Blazing Star 1, Crowned Ridge 2, Jeffers and Community Wind North), PSCo (Cheyenne Ridge) and SPS (Sagamore).

(b) Amounts settled primarily related to closure of certain ash containment facilities, removal of wind facilities and asbestos abatement projects.

(c) In 2020, AROs were revised for changes in timing and estimates of cash flows. Revisions in the nuclear AROs were driven by reductions in spent fuel cooling time requirements in the nuclear triennial filing coupled with decreasing interest rates. Changes in wind AROs were driven by new dismantling studies. Revisions in steam, hydro and other production AROs were primarily related to changes in cost estimates for remediation of ash containment facilities.

Indeterminate AROs — Other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2021. Therefore, an ARO was not recorded for these facilities.

Nuclear

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $13.5 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.0 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to $138 million per reactor-incident for each of its three reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $21 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.8 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350 million, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage.

NSP-Minnesota could be subject to annual maximum assessments of $11 million for business interruption insurance and $33 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 47 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life. A CON for additional storage at the Monticello site has been filed with the MPUC, to support possible life extension. NSP-Minnesota expects a decision by year-end 2023.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. The cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%.

Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota had $3.3 billion of assets held in external decommissioning trusts at Dec. 31, 2021. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements as an ARO.

	Regulatory Basis	
(Millions of Dollars)	**2021**	**2020**
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	1,006	844
Estimated decommissioning cost obligation (in current dollars)	4,018	3,856
Effect of escalating costs to payment date	7,187	7,349
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 1.96% and 1.64% for 2021 and 2020, respectively)	(4,651)	(4,181)
Discounted decommissioning cost obligation	$ 6,554	$ 7,024
Assets held in external decommissioning trust	$ 3,256	$ 2,777
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	3,298	4,247

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	**2021**	**2020**
Discounted decommissioning cost obligation - regulated basis	$ 6,554	$ 7,024
Differences in discount rate and market risk premium	(2,209)	(2,628)
O&M costs not included for GAAP	(1,584)	(1,734)
ARO differences between 2020 and 2014 cost studies	(705)	(705)
Nuclear production decommissioning ARO - GAAP	$ 2,056	$ 1,957

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	**2021**	**2020**	**2019**
Annual decommissioning recorded as depreciation expense: (a) (b)	$ 22	$ 20	$ 20

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2021, 2020 and 2019 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2017 nuclear decommissioning filing, effective Jan. 1, 2019, has been approved by the MPUC. In March 2020, the MPUC approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2021. In December 2020, the MPUC verbally approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2022. In December 2021, NSP-Minnesota submitted a Petition for approval of the 2022 - 2024 Nuclear Decommissioning Study and Assumptions. Contemplated but not proposed in this filing, was the 10-year extension of the license to operate the Monticello Plant, moving the planned retirement date from 2030 to 2040. The 2019 Preferred Integrated Resource Plan Supplement does include a 10-year extension of the license. On Feb. 8, 2022, the MPUC approved the 10-year extension.

Leases

Xcel Energy evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent Xcel Energy's rights to use leased assets. The present value of future operating lease payments is recognized in other current liabilities and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of Xcel Energy's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the applicable Xcel Energy subsidiary's estimated incremental borrowing rate (weighted average of 4.0%). Xcel Energy has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	**Dec. 31, 2021**	**Dec. 31, 2020**
PPAs	$ 1,656	$ 1,650
Other	225	212
Gross operating lease ROU assets	1,881	1,862
Accumulated amortization	(590)	(372)
Net operating lease ROU assets	$ 1,291	$ 1,490

ROU assets for finance leases are included in other noncurrent assets, and the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities.

Xcel Energy's most significant finance lease activities are related to WYCO, a joint venture with CIG, to develop and lease natural gas pipeline, storage and compression facilities. Xcel Energy Inc. has a 50% ownership interest in WYCO. WYCO leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage and transportation services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service and Front Range pipeline arrangements with CIG and WYCO, respectively, as finance leases. Xcel Energy Inc. eliminates 50% of the finance lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

Finance lease ROU assets:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Gas storage facilities	$ 201	$ 201
Gas pipeline	21	21
Gross finance lease ROU assets	222	222
Accumulated amortization	(97)	(90)
Net finance lease ROU assets	$ 125	$ 132

Components of lease expense:

(Millions of Dollars)	2021	2020	2019
Operating leases			
PPA capacity payments	$ 251	$ 238	$ 221
Other operating leases [(a)]	36	26	34
Total operating lease expense [(b)]	$ 287	$ 264	$ 255
Finance leases			
Amortization of ROU assets	$ 7	$ 7	$ 6
Interest expense on lease liability	17	18	19
Total finance lease expense	$ 24	$ 25	$ 25

(a) Includes short-term lease expense of $5 million for 2021, 2020 and 2019.

(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating and finance leases as of Dec. 31, 2021:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [(c)]
2022	$ 229	$ 27	$ 256	$ 12
2023	221	26	247	12
2024	209	22	231	12
2025	189	16	205	10
2026	146	12	158	9
Thereafter	416	81	497	187
Total minimum obligation	1,410	184	1,594	242
Interest component of obligation	(209)	(34)	(243)	(170)
Present value of minimum obligation	$ 1,201	150	1,351	72
Less current portion			(205)	(3)
Noncurrent operating and finance lease liabilities			$ 1,146	$ 69
Weighted-average remaining lease term in years			8.9	36.1

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2039.

(c) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2033, contain minimum energy purchase commitments. Total energy payments on those contracts were $149 million, $112 million and $102 million in 2021, 2020 and 2019, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $69 million, $75 million and $86 million in 2021, 2020 and 2019, respectively.

Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

At Dec. 31, 2021, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [(a)]
2022	$ 75	$ 165
2023	77	169
2024	72	174
2025	29	53
2026	12	10
Thereafter	12	38
Total	$ 277	$ 609

(a) Excludes contingent energy payments for renewable energy PPAs.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire between 2022 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2021:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2022	$ 620	$ 89	$ 477	$ 292
2023	233	109	75	224
2024	147	82	4	172
2025	29	119	—	156
2026	31	29	—	149
Thereafter	34	309	—	571
Total	$ 1,094	$ 737	$ 556	$ 1,564

VIEs

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. Xcel Energy has determined that certain IPPs are VIEs. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance.

The utility subsidiaries had approximately 4,062 MW of capacity under long-term PPAs at both Dec. 31, 2021 and 2020 with entities that have been determined to be VIEs. These agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO Inc. under contracts that will expire in December 2022. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs.

SPS has determined that TUCO is a VIE, however it has concluded that SPS is not the primary beneficiary of TUCO because it does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing partnerships to be VIEs primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not align with the partners' proportional equity ownership.

Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance. Therefore, Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements. Xcel Energy's risk of loss for these partnerships is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be, provided to the limited partnerships by Eloigne or NSP-Wisconsin.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Current assets	$ 7	$ 7
Property, plant and equipment, net	37	38
Other noncurrent assets	1	1
Total assets	$ 45	$ 46
Current liabilities	$ 7	$ 8
Mortgages and other long-term debt payable	27	25
Other noncurrent liabilities	1	1
Total liabilities	$ 35	$ 34

Other

Technology Agreements — Xcel Energy has several contracts for information technology services that extend through 2022. The contracts are cancelable, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $103 million, $110 million and $101 million associated with these contracts in 2021, 2020 and 2019, respectively.

Committed minimum payments under these obligations are $15 million in 2022.

Guarantees and Bond Indemnifications — Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum amount.

As of Dec. 31, 2021 and 2020, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements. Guarantees and bond indemnities issued and outstanding for Xcel Energy were $60 million and $62 million at Dec. 31, 2021 and 2020 respectively.

Other Indemnification Agreements — Xcel Energy Inc. and its subsidiaries provide indemnifications through various contracts. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

13. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31:

	2021		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (85)	$ (56)	$ (141)
Other comprehensive loss before reclassifications (net of taxes of $1 and $—, respectively)	4	—	4
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $2 and $—, respectively)	6 (a)	—	6
Amortization of net actuarial loss (net of taxes of $— and $3, respectively)	—	8 (b)	8
Net current period other comprehensive income	10	8	18
Accumulated other comprehensive loss at Dec. 31	$ (75)	$ (48)	$ (123)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

(Millions of Dollars)	2020 Gains and Losses on Cash Flow Hedges	2020 Defined Benefit Pension and Postretirement Items	2020 Total
Accumulated other comprehensive loss at Jan. 1	$ (80)	$ (61)	$ (141)
Other comprehensive loss before reclassifications (net of taxes of $(3) and $(2), respectively)	(10)	(5)	(15)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $2 and $—, respectively)	5 (a)	—	5
Amortization of net actuarial loss (net of taxes of $— and $3, respectively)	—	10 (b)	10
Net current period other comprehensive (loss) income	(5)	5	—
Accumulated other comprehensive loss at Dec. 31	$ (85)	$ (56)	$ (141)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

14. Segment Information

Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided, including the regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments:

- **Regulated Electric** — The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations.
- **Regulated Natural Gas** — The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Xcel Energy also presents All Other, which includes operating segments with revenues below the necessary quantitative thresholds. Those operating segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel, investments in rental housing projects that qualify for low-income housing tax credits and the operations of MEC until July 2020.

Xcel Energy had equity method investments of $208 million and $165 million as of Dec. 31, 2021 and 2020, respectively, included in the natural gas utility and all other segments.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments. As an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment. Reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations, which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

Certain costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators across each segment. In addition, a general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

Xcel Energy's segment information:

(Millions of Dollars)	2021	2020	2019
Regulated Electric			
Operating revenues — external	$ 11,205	$ 9,802	$ 9,575
Intersegment revenue	2	2	1
Total revenues	$ 11,207	$ 9,804	$ 9,576
Depreciation and amortization	1,855	1,673	1,535
Interest charges and financing costs	568	534	500
Income tax (benefit) expense	(96)	1	125
Net income	1,478	1,407	1,288
Regulated Natural Gas			
Operating revenues — external	$ 2,132	$ 1,636	$ 1,868
Intersegment revenue	2	1	2
Total revenues	$ 2,134	$ 1,637	$ 1,870
Depreciation and amortization	254	252	219
Interest charges and financing costs	75	71	69
Income tax expense	54	17	48
Net income	231	190	195
All Other			
Total revenues	$ 94	$ 88	$ 86
Depreciation and amortization	12	23	11
Interest charges and financing costs	173	193	167
Income tax benefit	(28)	(24)	(45)
Net loss	(112)	(124)	(111)
Consolidated Total			
Total revenues	$ 13,435	$ 11,529	$ 11,532
Reconciling eliminations	(4)	(3)	(3)
Total operating revenues	$ 13,431	$ 11,526	$ 11,529
Depreciation and amortization	2,121	1,948	1,765
Interest charges and financing costs	816	798	736
Income tax (benefit) expense	(70)	(6)	128
Net income	1,597	1,473	1,372

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of Dec. 31, 2021, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter ended Dec. 31, 2021 that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level.

During the year and in preparation for issuing its report for the year ended Dec. 31, 2021 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in Xcel Energy's Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

ITEM 9B — OTHER INFORMATION

None.

ITEM 9C — DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10 — DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is expected to occur on April 5, 2022, incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

ITEM 11 — EXECUTIVE COMPENSATION

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item (aggregate fees billed to us by our principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34)) is contained in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

ITEM 15 — EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

1	Consolidated Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2021.
	Report of Independent Registered Public Accounting Firm — Financial Statements and Internal Controls Over Financial Reporting
	Consolidated Statements of Income — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
	Consolidated Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
	Consolidated Statements of Cash Flows — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
	Consolidated Balance Sheets — As of Dec. 31, 2021 and 2020.
	Consolidated Statements of Common Stockholders' Equity — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2021, 2020, and 2019.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc. Form 8-K dated May 16, 2012	3.01
3.02*	Bylaws of Xcel Energy Inc. as Amended on April 3, 2020	Xcel Energy Inc. Form 8-K dated April 3, 2020	3.01
4.01*	Description of Securities	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	4.01

4.02*	Indenture dated Dec. 1, 2000 between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	4.01
4.03*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 6, 2006	4.01
4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	4.01
4.05*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	4.03
4.06*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	4.01
4.07*	Supplemental Indenture No. 8, dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 1, 2015	4.01
4.08*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	4.01
4.09*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 25, 2018	4.01
4.10*	Supplemental Indenture No. 12, dated as of Nov. 7, 2019 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating 2.60% Senior Notes, Series due Dec 1. 2029 and 3.50% Senior Notes, Series due Dec. 1, 2049	Xcel Energy Inc. Form 8-K dated Nov. 7, 2019	4.01
4.11*	Supplemental Indenture No. 13, dated as of April 1, 2020 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association as Trustee creating $600 million principal amount of 3.40% Senior Notes, Series due June 1, 2030	Xcel Energy Inc. Form 8-K dated April 1, 2020	4.01
4.12*	Supplemental Indenture No. 14, dated as of Sept. 25, 2020 between Xcel Energy Inc. and Wells Fargo Bank, National Association as Trustee, creating $500 million principal amount of 0.50% Senior Notes, Series due Oct. 15, 2023	Xcel Energy Inc. Form 8-K dated Sept. 25, 2020	4.01
4.13*	Supplemental Indenture No. 15, dated as of Nov. 3, 2021 between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $500 million principal amount of 1.75% Senior Notes, Series due March 15, 2027 and $300 million principal amount of 2.35% Senior Notes, Series due Nov. 15, 2031	Xcel Energy Inc. Form 8-K dated Nov. 3, 2021	4.01
10.01*	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.05
10.03*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.18
10.04*+	Fifth Amendment to Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	10.01
10.05*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	10.01
10.06*+	Eighth Amendment to Exhibit 10.02 dated March 31, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2020	10.02
10.07*+	Ninth Amendment to Exhibit 10.02 dated May 22, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2020	10.01
10.08*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.17
10.09*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	Appendix A
10.10*+	First Amendment to Exhibit 10.09 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	10.01
10.11*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	10.08
10.12*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.07
10.13*+	First Amendment to Exhibit 10.12 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.17
10.14*+	Second Amendment to Exhibit 10.12 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	10.22
10.15*+	Third Amendment to Exhibit 10.12 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	10.01
10.16*+	Fourth Amendment to Exhibit 10.12 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	10.1
10.17*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.34
10.18*+	Form of Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan for Awards of Restricted Stock Units and/or Performance Share Units	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.35
10.19*+	Form of Award Agreement for Restricted Stock Units and/or Performance Share Units under the Xcel Energy Inc. 2015 Omnibus Incentive Plan for awards since 2020	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	10.32
10.20*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	Appendix A
10.21*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	10.02
10.22*+	Summary of Non-Employee Director Compensation, effective as of Oct. 1, 2021	Xcel Energy Inc. Form 10-Q for the quarter ended September 30, 2021	10.01
10.23*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.36
10.24*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	H-1

10.25*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.01
10.26*	364-Day Term Loan Agreement dated as of February 18, 2021 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and U.S. Bank National Association, as Administrative Agent.	Xcel Energy Inc. Form 8-K dated February 18, 2021	10.01
10.27*+	Form of Award Agreement for Retention-Based Restricted Stock Units under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated December 10, 2021	10.01
NSP-Minnesota			
4.14*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(3)
4.15*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due July 1, 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.11
4.16*	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due March 1, 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.12
4.17*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.51
4.18*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(7)
4.19*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.63
4.20*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	4.01
4.21*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	4.01
4.22*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	4.01
4.23*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and the Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	4.01
4.24*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.95% First Mortgage Bonds, Series due Aug, 15, 2015 and $250 principal amount of 4.85% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	4.01
4.25*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	4.01
4.26*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due May 15, 2023	NSP-Minnesota Form 8-K dated May 20, 2013	4.01
4.27*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044	NSP-Minnesota Form 8-K dated May 13, 2014	4.01
4.28*	Supplemental Trust Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and the Bank of New York Mellon Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due Aug. 15, 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due Aug. 15, 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	4.01
4.29*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and the Bank of NY Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.60% First Mortgage Bonds, Series due May 15, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	4.01
4.31*	Supplemental Trust Indenture dated as of Sept. 1, 2019 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 2.90% First Mortgage Bonds, Series due March 1, 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	4.01
4.32*	Supplemental Indenture dated as of June 8, 2020 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $700 million principal amount of 2.60% First Mortgage Bonds, Series due June 1, 2051	NSP-Minnesota 8-K dated June 15, 2020	4.01
4.33*	Supplemental Indenture dated as of March 1, 2021 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $425 million principal amount of 2.25% First Mortgage Bonds, Series due April 1, 2031 and $425 million principal amount of 3.20% First Mortgage Bonds, Series due April 1, 2052	NSP-Minnesota 8-K dated March 30, 2021	4.01
10.28*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.29*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.02
NSP-Wisconsin			
4.34*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust Company, providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(c)(3)
4.35*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	4.01

4.36*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	4.01
4.37*	Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.70% First Mortgage Bonds, Series due Oct. 1, 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	4.01
4.38*	Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30% First Mortgage Bonds, Series due June 1, 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	4.01
4.39*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.75% First Mortgage Bonds, Series due Dec. 1, 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	4.01
4.40*	Supplemental Indenture dated as of Sept. 1, 2018 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 4.20% First Mortgage Bonds, Series due Sept. 1, 2048	NSP-Wisconsin Form 8-K dated Sept. 12, 2018	4.01
4.41*	Supplemental Indenture dated as of May 18, 2020 between NSP-Wisconsin and U.S. Bank National Association, as Trustee, creating $100 million principal amount of 3.05% First Mortgage Bonds, Series due May 1, 2051	NSP-Wisconsin Form 8-K dated May 26, 2020	4.01
4.42*	Supplemental Indenture dated as of July 19, 2021 between NSP-Wisconsin and U.S. Bank National Association, as Trustee, creating $100 million principal amount of 2.82% First Mortgage Bonds, Series due May 1, 2051	NSP-Wisconsin Form 8-K dated July 20, 2021	4.01
10.30*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.31*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.05
10.32*	Bond Purchase Agreement, dated July 19, 2021, among NSP-Wisconsin and the several purchasers listed in Schedule B thereto	NSP-Wisconsin Form 8-K dated July 20, 2021	1.01
PSCo			
4.43*	Indenture, dated as of Oct. 1, 1993 between PSCo and Morgan Guaranty Trust Company of New York, as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(d)(3)
4.44*	Supplemental Indenture, dated Aug. 1, 2007 between PSCo and U.S. Bank Trust National Association, as successor Trustee	PSCo Form 8-K dated Aug. 8, 2007	4.01
4.45*	Supplemental Indenture dated as of Aug. 1, 2008 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80% First Mortgage Bonds, Series due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series due 2038	PSCo Form 8-K dated Aug. 6, 2008	4.01
4.46*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75% First Mortgage Bonds, Series due 2041	PSCo Form 8-K dated Aug. 9, 2011	4.01
4.47*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series due 2042	PSCo Form 8-K dated Sept. 11, 2012	4.01
4.48*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50% First Mortgage Bonds, Series due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series due 2043	PSCo Form 8-K dated March 26, 2013	4.01
4.49*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30% First Mortgage Bonds, Series due 2044	PSCo Form 8-K dated March 10, 2014	4.01
4.50*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.90% First Mortgage Bonds, Series due 2025	PSCo Form 8-K dated May 12, 2015	4.01
4.51*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 3.55% First Mortgage Bonds, Series due 2046	PSCo Form 8-K dated June 13, 2016	4.01
4.52*	Supplemental Indenture dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.80% First Mortgage Bonds, Series due 2047	PSCo Form 8-K dated June 19, 2017	4.01
4.53*	Supplemental Indenture dated as of June 1, 2018 between PSCo and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70% First Mortgage Bonds, Series due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series due 2048	PSCo Form 8-K dated June 21, 2018	4.01
4.54*	Supplemental Indenture dated as of March 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 4.05% First Mortgage Bonds, Series due 2049	PSCo Form 8-K dated March 13, 2019	4.01
4.55*	Supplemental Indenture dated as of Aug. 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $550 million principal amount of 3.20% First Mortgage Bonds, Series due 2050	PSCo Form 8-K dated August 13, 2019	4.01
4.56*	Supplemental Indenture dated as of May 1, 2020 between PSCo and U.S. Bank National Association, as successor Trustee, creating $375 million principal of 2.70% First Mortgage Bonds, Series No. 35 due 2051 and $375 million principal amount of 1.90% First Mortgage Bonds, Series No. 36 due 2031	PSCo Form 8-K dated May 15, 2020	4.01
4.57*	Supplemental Indenture dated as of February 1, 2021 between PSCo and U.S. Bank National Association, as successor Trustee, creating $750 million principal of 1.875% First Mortgage Bonds, Series No. 37 due 2031	PSCo Form 8-K dated March 1, 2021	4.01
10.33*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	99.02
10.34*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.03
SPS			
4.58*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	99.2
4.59*	Supplemental Indenture dated Oct. 1, 2003 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6% due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	4.04
4.60*	Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee, creating $200 million principal amount of 5.6% Series E Notes due 2016 and $250 million principal amount of 6% Series F Notes due 2036	SPS Form 8-K dated Oct. 3, 2006	4.01
4.61*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	4.01

4.62*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series due 2041	SPS Form 8-K dated Aug. 10, 2011	4.02
4.63*	Supplemental Indenture dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	SPS Form 8-K dated June 9, 2014	4.02
4.64*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series due 2046	SPS Form 8-K dated Aug. 12, 2016	4.02
4.65*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series due 2047	SPS Form 8-K dated Aug 9. 2017	4.02
4.66*	Supplemental Indenture dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 4.40% First Mortgage Bonds, Series due 2048	SPS Form 8-K dated Nov. 5, 2018	4.02
4.67*	Supplemental Indenture dated as of June 1, 2019 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.75% First Mortgage Bonds, Series due 2049	SPS Form 8-K dated June 18, 2019	4.02
4.68*	Supplemental Indenture No. 8, dated as of May 1, 2020 between SPS and U.S. Bank National Association, as Trustee, creating $600 million principal amount of 3.15% First Mortgage Bonds, Series due 2050	SPS Form 8-K dated May 18, 2020	4.02
10.35*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.04

Xcel Energy Inc.	
21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm
24.01	Powers of Attorney
31.01	Principal Executive Officer’s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.02	Principal Financial Officer’s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH	Inline XBRL Schema
101.CAL	Inline XBRL Calculation
101.DEF	Inline XBRL Definition
101.LAB	Inline XBRL Label
101.PRE	Inline XBRL Presentation
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

SCHEDULE I

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2021	2020	2019
Income			
Equity earnings of subsidiaries	$ 1,744	$ 1,646	$ 1,505
Total income	1,744	1,646	1,505
Expenses and other deductions			
Operating expenses	21	43	23
Other income	3	(4)	(9)
Interest charges and financing costs	173	198	173
Total expenses and other deductions	197	237	187
Income before income taxes	1,547	1,409	1,318
Income tax benefit	(50)	(64)	(54)
Net income	$ 1,597	$ 1,473	$ 1,372
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $ 1, $1 and $1, respectively	$ 8	$ 5	$ 3
Derivative instruments, net of tax of $3, $(1) and $(7), respectively	10	(5)	(20)
Other comprehensive income (loss)	18	—	(17)
Comprehensive income	$ 1,615	$ 1,473	$ 1,355
Weighted average common shares outstanding:			
Basic	539	527	519
Diluted	540	528	520
Earnings per average common share:			
Basic	$ 2.96	$ 2.79	$ 2.64
Diluted	2.96	2.79	2.64

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2021	2020	2019
Operating activities			
Net cash provided by operating activities	$ 1,147	$ 2,377	$ 1,389
Investing activities			
Capital contributions to subsidiaries	(1,661)	(2,553)	(1,594)
Net return (investments) in the utility money pool	57	(18)	39
Other, net	—	(1)	—
Net cash used in investing activities	(1,604)	(2,572)	(1,555)
Financing activities			
Proceeds (repayment of) from short-term borrowings, net	638	(500)	12
Proceeds from issuance of long-term debt	791	1,089	1,120
Repayment of long-term debt	(400)	(300)	(550)
Proceeds from issuance of common stock	366	727	458
Repurchase of common stock	—	(4)	—
Dividends paid	(935)	(856)	(791)
Other	(16)	(17)	(14)
Net cash provided by financing activities	444	139	235
Net change in cash, cash equivalents, and restricted cash	(13)	(56)	69
Cash, cash equivalents and restricted cash at beginning of period	14	70	1
Cash, cash equivalents and restricted cash at end of period	$ 1	$ 14	$ 70

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2021	2020
Assets		
Cash and cash equivalents	$ 1	$ 14
Accounts receivable from subsidiaries	430	424
Other current assets	6	6
Total current assets	437	444
Investment in subsidiaries	21,167	19,102
Other assets	71	40
Total other assets	21,238	19,142
Total assets	$ 21,675	$ 19,586
Liabilities and Equity		
Current portion of long-term debt	—	400
Dividends payable	249	231
Short-term debt	638	—
Other current liabilities	29	21
Total current liabilities	916	652
Other liabilities	10	17
Total other liabilities	10	17
Commitments and contingencies		
Capitalization		
Long-term debt	5,137	4,342
Common stockholders' equity	15,612	14,575
Total capitalization	20,749	18,917
Total liabilities and equity	$ 21,675	$ 19,586

See Notes to Condensed Financial Statements

Notes to Condensed Financial Statements

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and other comprehensive income in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Guarantees and Indemnifications

Xcel Energy Inc. provides guarantees and bond indemnities under specified agreements or transactions, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. limit the exposure to a maximum stated amount. As of Dec. 31, 2021 and 2020, Xcel Energy Inc. had no assets held as collateral related to guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding as of Dec. 31, 2021:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of loan for Hiawatha Collegiate High School [(a)]	Xcel Energy Inc.	$ 1	—	(c)
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries [(b)]	Xcel Energy Inc.	59	(e)	(d)

(a) The term of this guarantee expires the earlier of 2024 or full repayment of the loan.

(b) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.

(c) Nonperformance and/or nonpayment.

(d) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.

(e) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. provides indemnifications through contracts entered into in the normal course of business. Indemnifications are primarily against adverse litigation outcomes in connection with underwriting agreements, breaches of representations and warranties, including corporate existence, transaction authorization and certain income tax matters. Obligations under these agreements may be limited in terms of duration or amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Related Party Transactions — Xcel Energy Inc. presents related party receivables net of payables. Accounts receivable net of payables with affiliates at Dec. 31:

(Millions of Dollars)	2021	2020
NSP-Minnesota	$ 104	$ 81
NSP-Wisconsin	25	9
PSCo	91	98
SPS	58	55
Xcel Energy Services Inc.	125	159
Other subsidiaries of Xcel Energy Inc.	27	22
	$ 430	$ 424

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $1,344 million, $2,527 million and $2,987 million for the years ended Dec. 31, 2021, 2020 and 2019, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool — FERC approval was received to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2021
Loan outstanding at period end	$ —
Average loan outstanding	—
Maximum loan outstanding	—
Weighted average interest rate, computed on a daily basis	N/A
Weighted average interest rate at end of period	N/A
Money pool interest income	$ —

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2021	Year Ended Dec. 31, 2020	Year Ended Dec. 31, 2019
Loan outstanding at period end	$ —	$ 57	$ 39
Average loan outstanding	16	104	47
Maximum loan outstanding	439	350	250
Weighted average interest rate, computed on a daily basis	0.08 %	0.60 %	2.15 %
Weighted average interest rate at end of period	N/A	0.07 %	1.63
Money pool interest income	$ —	$ 1	$ 1

See notes to the consolidated financial statements in Part II, Item 8.

SCHEDULE II

Xcel Energy Inc. and Subsidiaries Valuation and Qualifying Accounts Years Ended Dec. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2021	2020	2019	2021	2020	2019
Balance at Jan. 1	$ 79	$ 55	$ 55	$ 64	$ 67	$ 79
Additions charged to costs and expenses	60	60	42	5	6	9
Additions charged to other accounts	14 (a)	12 (a)	16 (a)	—	—	—
Deductions from reserves	(47) (b)	(48) (b)	(58) (b)	(5) (d)	(9) (c)	(21) (d)
Balance at Dec. 31	$ 106	$ 79	$ 55	$ 64	$ 64	$ 67

(a) Recovery of amounts previously written-off.

(b) Deductions related primarily to bad debt write-offs.

(c) Primarily the reduction of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability forecasted to be used prior to expiration along with valuation allowances that expired.

(d) Primarily reductions to valuation allowances due to additional NOLs and tax credits forecasted to be used prior to expiration.

ITEM 16 — FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 23, 2022	By:	/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Senior Vice President, Controller (Principal Accounting Officer)
*	Lynn Casey	Director
*	Netha N. Johnson	Director
*	Patricia L. Kampling	Director
*	George J. Kehl	Director
*	Richard T. O'Brien	Director
*	Charles Pardee	Director
*	Christopher J. Policinski	Director
*	James Prokopanko	Director
*	David A. Westerlund	Director
*	Kim Williams	Director
*	Timothy V. Wolf	Director
*	Daniel Yohannes	Director
*By:	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Attorney-in-Fact

XCEL ENERGY BOARD OF DIRECTORS

SHAREHOLDER INFORMATION

Headquarters
414 Nicollet Mall, Minneapolis, MN 55401

Website
investors.xcelenergy.com

Stock Transfer Agent
EQ Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
Telephone: 877-778-6786, toll free

Reports Available Online
Financial reports, including filings with the Securities and Exchange Commission and Xcel Energy's Report to Shareholders, are available online at xcelenergy.com; click on Investor Relations. Other information about Xcel Energy, including our Code of Conduct, Guidelines on Corporate Governance, Sustainability Report and Committee Charters, is also available at xcelenergy.com.

Stock Exchange Listings and Ticker Symbol
Common stock is listed on the Nasdaq Global Select Market (Nasdaq) under the ticker symbol XEL. In newspaper listings, it may appear as XcelEngy.

Investor Relations
Website: xcelenergy.com or contact Paul Johnson,
Vice President, Treasurer & Investor Relations, at 612-215-4535.

Shareholder Services
Website: investors.xcelenergy.com or contact Darin Norman,
Senior Analyst, Investor Relations, at 612-337-2310 or
email darin.norman@xcelenergy.com.

Corporate Governance
Xcel Energy has filed with the Securities and Exchange Commission certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2021.

To contact the Board of Directors, send an email to boardofdirectors@xcelenergy.com.

You also may direct questions to the Corporate Secretary's department at corporatesecretary@xcelenergy.com.

FISCAL AGENTS

XCEL ENERGY INC.
Transfer Agent, Registrar, Dividend Distribution, Common Stock
EQ Shareowner Services,
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120

Trustee–Bonds
Computershare Corporate Trust
MAC 9300-070
600 South 4th Street
Minneapolis, MN 55415

Schedule Q-4

Reports to the Securities and Exchange Commission

Table of Contents

2021 Form 10-Q

For the Quarterly Period Ended

March 31, 2021

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2021

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-03789

Southwestern Public Service Company
(Exact name of registrant as specified in its charter)

New Mexico	**75-0575400**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
790 South Buchanan Street Amarillo Texas	**79101**
(Address of Principal Executive Offices)	(Zip Code)

303 571-7511
(Registrant's Telephone Number, Including Area Code)

N/A
(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☐	Accelerated Filer ☐
Non-accelerated Filer ☒	Smaller Reporting Company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	April 29, 2021
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

TABLE OF CONTENTS

This Form 10-Q is filed by Southwestern Public Service Company, a New Mexico corporation (SPS). SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the Securities and Exchange Commission. This report should be read in its entirety.

Table of Contents

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies	
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses	
DSM	Demand side management
FPPCAC	Fuel and Purchased Power Cost Adjustment Clause

Other	
ASC	FASB Accounting Standards Codification
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	United States generally accepted accounting principles
IPP	Independent power producing entity
LLC	Limited liability company
NOL	Net operating loss
NOPR	Notice of Proposed Rulemaking
O&M	Operating and maintenance
OATT	Open access transmission tariff
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
ROFR	Right-of-first-refusal
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
VIE	Variable interest entity

Measurements	
MW	Megawatts

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impacts on our results of operations, financial condition and cash flows or resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly Report on Form 10-Q and in other filings with the SEC (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2020, and subsequent filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

Table of Contents

PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31	
	2021	**2020**
Operating revenues	$ 934	$ 395
Operating expenses		
Electric fuel and purchased power	693	188
Operating and maintenance expenses	71	70
Demand side management expenses	4	4
Depreciation and amortization	78	59
Taxes (other than income taxes)	21	21
Total operating expenses	867	342
Operating income	67	53
Other income (expense), net	1	(2)
Allowance for funds used during construction — equity	1	6
Interest charges and financing costs		
Interest charges — includes other financing costs of $1 and $1, respectively	30	24
Allowance for funds used during construction — debt	—	(3)
Total interest charges and financing costs	30	21
Income before income taxes	39	36
Income tax benefit	(19)	(7)
Net income	$ 58	$ 43

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31	
	2021	2020
Operating activities		
Net income	$ 58	$ 43
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	79	60
Deferred income taxes	(19)	1
Allowance for equity funds used during construction	(1)	(6)
Provision for bad debts	2	1
Changes in operating assets and liabilities:		
Accounts receivable	(1)	(3)
Accrued unbilled revenues	3	12
Inventories	(17)	(7)
Prepayments and other	21	(5)
Accounts payable	56	(2)
Net regulatory assets and liabilities	(95)	18
Other current liabilities	(3)	(15)
Pension and other employee benefit obligations	(15)	(15)
Other, net	(2)	—
Net cash provided by operating activities	66	82
Investing activities		
Utility capital/construction expenditures	(172)	(193)
Investments in utility money pool arrangement	(83)	(4)
Repayments from utility money pool arrangement	83	4
Net cash used in investing activities	(172)	(193)
Financing activities		
Repayments of short-term borrowings, net	(250)	40
Proceeds from issuance of long-term debt, net	247	—
Borrowings under utility money pool arrangement	213	239
Repayments under utility money pool arrangement	(213)	(139)
Capital contributions from parent	304	31
Dividends paid to parent	(54)	(74)
Net cash provided by financing activities	247	97
Net change in cash, cash equivalents and restricted cash	141	(14)
Cash, cash equivalents and restricted cash at beginning of period	6	16
Cash, cash equivalents and restricted cash at end of period	$ 147	$ 2
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (19)	$ (18)
Cash received (paid) for income taxes, net	14	(2)
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 54	$ 57
Inventory transfers to property, plant and equipment	7	6
Allowance for equity funds used during construction	1	6

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	March 31, 2021	Dec. 31, 2020
Assets		
Current assets		
Cash and cash equivalents	$ 147	$ 6
Accounts receivable, net	101	94
Accounts receivable from affiliates	2	9
Accrued unbilled revenues	112	114
Inventories	45	36
Regulatory assets	157	76
Derivative instruments	13	10
Prepayments and other	17	38
Total current assets	594	383
Property, plant and equipment, net	7,697	7,603
Other assets		
Regulatory assets	346	357
Derivative instruments	11	9
Operating lease right-of-use assets	485	492
Other	14	15
Total other assets	856	873
Total assets	$ 9,147	$ 8,859
Liabilities and Equity		
Current liabilities		
Short-term debt	$ —	$ 250
Accounts payable	224	198
Accounts payable to affiliates	33	17
Regulatory liabilities	32	57
Taxes accrued	43	54
Accrued interest	38	29
Dividends payable to parent	52	54
Derivative instruments	4	4
Operating lease liabilities	28	28
Other	23	25
Total current liabilities	477	716
Deferred credits and other liabilities		
Deferred income taxes	712	725
Regulatory liabilities	723	718
Asset retirement obligations	113	112
Derivative instruments	8	9
Pension and employee benefit obligations	27	42
Operating lease liabilities	457	463
Other	11	12
Total deferred credits and other liabilities	2,051	2,081
Commitments and contingencies		
Capitalization		
Long-term debt	3,011	2,764
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at March 31, 2021 and Dec. 31, 2020, respectively	—	—
Additional paid in capital	3,094	2,790
Retained earnings	515	509
Accumulated other comprehensive loss	(1)	(1)
Total common stockholder's equity	3,608	3,298
Total liabilities and equity	$ 9,147	$ 8,859

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended March 31, 2021 and 2020						
Balance at Dec. 31, 2019	100	$ —	$ 2,351	$ 535	$ (1)	$ 2,885
Net income				43		43
Dividends declared to parent				(76)		(76)
Contributions of capital by parent			32			32
Balance at March 31, 2020	100	$ —	$ 2,383	$ 502	$ (1)	$ 2,884
Balance at Dec. 31, 2020	100	$ —	$ 2,790	$ 509	$ (1)	$ 3,298
Net income				58		58
Dividends declared to parent				(52)		(52)
Contributions of capital by parent			304			304
Balance at March 31, 2021	100	$ —	$ 3,094	$ 515	$ (1)	$ 3,608

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with GAAP, the financial position of SPS as of March 31, 2021 and Dec. 31, 2020; the results of its operations, including the components of net income, comprehensive income, cash flows and changes in stockholder's equity for the three months ended March 31, 2021 and 2020.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2021 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2020 balance sheet information has been derived from the audited 2020 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020.

These notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto, included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020, filed with the SEC on Feb. 17, 2021. Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

SPS implemented the guidance using a modified-retrospective approach, recognizing an immaterial cumulative effect charge (after tax) to retained earnings on Jan. 1, 2020. The Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	March 31, 2021	Dec. 31, 2020
Accounts receivable, net		
Accounts receivable	$ 110	$ 102
Less allowance for bad debts	(9)	(8)
Accounts receivable, net	$ 101	$ 94

(Millions of Dollars)	March 31, 2021	Dec. 31, 2020
Inventories		
Materials and supplies	$ 27	$ 27
Fuel	18	9
Total inventories	$ 45	$ 36

(Millions of Dollars)	March 31, 2021	Dec. 31, 2020
Property, plant and equipment, net		
Electric plant	$ 9,293	$ 9,229
Plant to be retired [(a)]	313	316
CWIP	235	146
Total property, plant and equipment	9,841	9,691
Less accumulated depreciation	(2,144)	(2,088)
Property, plant and equipment, net	$ 7,697	$ 7,603

(a) Includes expected retirement of Tolk and conversion of Harrington to natural gas.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for SPS were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	—	—
Average amount outstanding	17	43
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	0.07 %	0.54 %
Weighted average interest rate at period end	N/A	N/A

Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	—	250
Average amount outstanding	184	44
Maximum amount outstanding	342	250
Weighted average interest rate, computed on a daily basis	0.22 %	1.11 %
Weighted average interest rate at period end	N/A	0.29

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. At both March 31, 2021 and Dec. 31, 2020, there were $2 million of letters of credit outstanding under the credit facility. Amounts approximate their fair value and are subject to fees.

Table of Contents

Revolving Credit Facility — In order to issue its commercial paper, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of March 31, 2021, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 2	$ 498

(a) Expires in June 2024.
(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of March 31, 2021 and Dec. 31, 2020.

Long-Term Borrowings

During the three months ended March 31, 2021, SPS issued $250 million of 3.15% first mortgage bonds due 2050.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/ customer type. SPS' operating revenues consisted of the following:

	Three Months Ended March 31	
(Millions of Dollars)	**2021**	**2020**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 91	$ 73
C&I	189	169
Other	9	8
Total retail	289	250
Wholesale	558	73
Transmission	71	63
Other	2	—
Total revenue from contracts with customers	920	386
Alternative revenue and other	14	9
Total revenues	$ 934	$ 395

6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2020 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

The following table reconciles the difference between the statutory rate and the ETR:

	Three Months Ended March 31	
	2021	**2020** [(a)]
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.6	2.4
Decreases in tax from:		
Wind PTCs	(65.5)	(35.7)
Plant regulatory differences [(b)]	(4.7)	(6.1)
Amortization of excess nonplant deferred taxes	(1.2)	(1.1)
Other (net)	(0.9)	0.1
Effective income tax rate	(48.7)%	(19.4)%

(a) Prior periods have been restated to conform to current year presentation.
(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

Federal Audits — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's federal income tax returns expire as follows:

Tax Years	Expiration
2014 — 2016	January 2022
2017	September 2021

Additionally, the statute of limitations related to the federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of March 31, 2021, SPS' earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2012. As of March 31, 2021, there are no state income tax audits in progress.

Unrecognized Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	March 31, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	$ 3	$ 3
Unrecognized tax benefit — Temporary tax positions	4	4
Total unrecognized tax benefit	$ 7	$ 7

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	March 31, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	$ (7)	$ (6)

As the IRS and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $5 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Table of Contents

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	March 31, 2021	Dec. 31, 2020
(Payable) receivable for interest related to unrecognized tax benefits at beginning of period	$ (1)	$ 1
Interest expense related to unrecognized tax benefits	—	(2)
Payable for interest related to unrecognized tax benefits at end of period	$ (1)	$ (1)

No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2021 and Dec. 31, 2020, respectively.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as FTRs, purchased from SPP. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of March 31, 2021, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Amounts in Millions [(a)]	March 31, 2021	Dec. 31, 2020
Megawatt hours of electricity	8	5

(a) Amounts are not reflective of net positions in the underlying commodities.

Table of Contents

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

At March 31, 2021, two of the eight most significant counterparties for these activities, comprising $17 million, or 38%, of this credit exposure, had investment grade ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Five of the eight most significant counterparties, comprising $27 million, or 61%, of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were no gains or losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three months ended March 31, 2021 and 2020, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains of $2 million and immaterial gains recognized for the three months ended March 31, 2021, and 2020, respectively, which were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement losses of $4 million and gains of $3 million were recognized for the three months ended March 31, 2021, and 2020, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three months ended March 31, 2021 and 2020.

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis:

	March 31, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 10	$ 10	$ —	$ 10	$ —	$ —	$ 7	$ 7	$ —	$ 7
Total current derivative assets	$ —	$ —	$ 10	$ 10	$ —	10	$ —	$ —	$ 7	$ 7	$ —	7
PPAs (b)						3						3
Current derivative instruments						$ 13						$ 10
Noncurrent derivative assets												
Electric commodity	$ —	$ —	$ 2	$ 2	$ —	$ 2	$ —	$ —	$ —	$ —	$ —	$ —
PPAs (b)						9						9
Noncurrent derivative instruments						$ 11						$ 9

	March 31, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
PPAs (b)						$ 4						$ 4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs (b)						$ 8						$ 9
Noncurrent derivative instruments						$ 8						$ 9

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at March 31, 2021 and Dec. 31, 2020. At March 31, 2021 and Dec. 31, 2020, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Table of Contents

Changes in Level 3 commodity derivatives for the three months ended March 31, 2021 and 2020:

(Millions of Dollars)	Three Months Ended March 31 2021	2020
Balance at Jan. 1	$ 7	$ 12
Purchases	—	12
Settlements	(9)	(5)
Net transactions recorded during the period:		
Net gains (losses) recognized as regulatory assets and liabilities	14	(2)
Balance at March 31	$ 12	$ 17

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three months ended March 31, 2021 and 2020.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	March 31, 2021		Dec. 31, 2020	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 3,011	$ 3,286	$ 2,764	$ 3,381

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of March 31, 2021 and Dec. 31, 2020 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended March 31	
	2021	2020
(Millions of Dollars)	Pension Benefits	
Service cost	$ 2	$ 2
Interest cost [(a)]	4	5
Expected return on plan assets [(a)]	(7)	(7)
Amortization of net loss [(a)]	4	3
Net benefit cost recognized for financial reporting	$ 3	$ 3

(a) The components of net periodic cost other than the service cost component are included in the line item "Other income (expense), net" in the statements of income or capitalized on the balance sheets as a regulatory asset.

In January 2021, contributions of $125 million were made across four of Xcel Energy's pension plans, of which $14 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2021.

9. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to SPS's financial position.

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters and Other

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. SPS has intervened in both appeals in support of the FERC. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. This appeal is stayed pending the outcome of the separate appeal initiated in 2020 by Oklahoma Gas & Electric and SPP.

Table of Contents

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include the costs of the GridLiance High Plains, LLC facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT. SPP's proposed tariff changes resulted in an increase in the annual transmission revenue requirement of $10 million per year, with $6 million allocated to SPS' retail customers. The remaining $4 million would be paid by other wholesale loads in the SPS rate zone. On March 16, 2020, GridLiance also filed additional rate increases for 2020 which would raise their annual revenue requirement to $14 million, with approximately $9 million allocated to SPS' retail customers. The hearing portion of this proceeding was concluded on Sept. 11, 2020.

The initial post-hearing brief was filed on Oct. 27, 2020 and the Administrative Law Judge's decision on this case is expected on May 3, 2021. The FERC will then rule on the judge's decision and either sustain it, overturn it, or order further proceedings. SPS has incurred approximately $17 million in associated charges as of March 31, 2021. In August 2020, FERC issued an order on a question certified by the hearing judge for the FERC's review, in which FERC made certain findings in SPS' favor regarding the legal standard that applies to the ongoing hearing proceeding. In November 2020, FERC denied GridLiance's request for rehearing of the August 2020 order. In December 2020, GridLiance filed a petition for review at the D.C. Circuit of the August 2020 and November 2020 orders on the certified question.

Contract Termination — SPS and Lubbock Power & Light are parties to a 25-year, 170 MW partial requirements contract. In October 2020, Lubbock Power & Light initiated discussions with SPS concerning the interpretation of contractual terms related to early termination and default. If the parties are unable to reach resolution, the contract calls for the matter to proceed to arbitration. The amount of any damages depends on multiple factors and is currently unknown.

FERC NOPR on ROE Incentive Adders — In April 2021, the FERC issued a NOPR proposing to limit collection of ROE incentive adders for RTO membership to the first three years after an entity begins participation in an RTO. If adopted as a final rule, following a comment period expected to be complete by the end of 2021 or 2022, NSP-Minnesota, NSP-Wisconsin and SPS would prospectively discontinue charging their current 0.5% ROE incentive adders. Amounts related to a discontinuance of the adder would ultimately be offset by an increase in retail rates.

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites — SPS is currently remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

	Three Months Ended March 31	
(Millions of Dollars)	**2021**	**2020**
Operating leases		
PPA capacity payments	$ 13	$ 11
Other operating leases [(a)]	1	1
Total operating lease expense [(b)]	$ 14	$ 12

(a) Includes immaterial short-term lease expense for 2021 and 2020.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating leases as of March 31, 2021:

(Millions of Dollars)	PPA Operating Leases	Other Operating Leases	Total Operating Leases
Total minimum obligation	$ 578	$ 58	$ 636
Interest component of obligation	(134)	(17)	(151)
Present value of minimum obligation	$ 444	$ 41	485
Less current portion			(28)
Noncurrent operating and finance lease liabilities			$ 457

VIEs

Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that it purchases. These specific PPAs create a variable interest in the IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs at both March 31, 2021 and Dec. 31, 2020 with entities that have been determined to be VIEs. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

ITEM 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for SPS is omitted per conditions set forth in general instructions H(1)(a) and (b) of Form 10-Q for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in general instructions H(2)(a) of Form 10-Q for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as, electric margin and ongoing earnings.

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

Table of Contents

SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, O&M expenses, DSM expenses, depreciation and amortization and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $58 million for the three months ended March 31, 2021 compared with approximately $43 million for the prior year, reflecting higher electric margin (regulatory outcomes in Texas and New Mexico), partially offset by increased depreciation.

Electric Margin

Electric revenues and fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses.

Electric revenues and margin:

	Three Months Ended March 31	
(Millions of Dollars)	**2021**	**2020**
Electric revenues [(a)]	$ 934	$ 395
Electric fuel and purchased power [(a)]	(693)	(188)
Electric margin	$ 241	$ 207

(a) The increase in revenue and electric fuel and purchased power is primarily due to Winter Storm Uri, resulting in higher fuel prices, as well as additional long-term energy and SPP market purchases.

Changes in electric margin:

(Millions of Dollars)	**Three Months Ended March 31, 2021 vs. 2020**
Regulatory rate outcomes (Texas and New Mexico)	$ 21
Wholesale transmission revenue (net)	9
Proprietary commodity trading, net of sharing	4
Estimated impact of weather	4
PTCs flowed back to customers (offset by lower ETR)	(11)
Other (net)	7
Total increase in electric margin	$ 34

Non-Fuel Operating Expense and Other Items

Depreciation and Amortization — Depreciation and amortization increased $19 million, or 32.2%, year-to-date. The increase was primarily due to the Sagamore wind farm being placed in service in December 2020, in addition to system expansion. The increase is also due to new FERC transmission rates applied in March 2020 and implementation of new depreciation rates in both New Mexico and Texas as part of regulatory outcomes in 2020.

AFUDC, Equity and Debt — AFUDC decreased $8 million for the first quarter of 2021, primarily due to construction of the Sagamore wind farm during 2020.

Income Taxes — Income tax benefit increased $12 million for the first quarter of 2021. The increase was primarily driven by an increase in wind PTCs. Wind PTCs are largely credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

See Note 6 to the financial statements for further information.

Other

Winter Storm Uri

In mid-February 2021, the central portion of the United States experienced a major winter storm (Winter Storm Uri). Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation across the region. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. Despite the extreme conditions, SPS' customers experienced minimal disruptions as a result of preemptive infrastructure investments and the response of our employees.

As a result of the extremely high market prices, SPS' electric fuel and purchased energy costs, including additional long-term energy and SPP market purchases, increased significantly. SPS mitigated the customer impact by approximately $135 million primarily through sales of excess generation. Approximately $80 million of related costs were deferred as regulatory assets.

Certain energy transactions are subject to final Independent System Operator re-settlement calculations and the impacts of credit losses shared among market participants. Such adjustments are not expected to be material to our results of operations, financial condition or cash flows.

Regulatory Overview — SPS has electric fuel and purchased energy mechanisms in each jurisdiction for the purpose of recovering incurred costs. However, February cost increases were deferred for future recovery and recovery proposed over a period of up to two years in order to significantly mitigate the impact to customer bills. Additionally, SPS is not requesting recovery of associated financing costs in order to further limit the impact to our customers.

The following proceedings have been initiated:

Jurisdiction	Regulatory Status
Texas	SPS intends to file for a surcharge in the second quarter to recover fuel costs over 24 months with no financing charge. Prudence of fuel costs will be subject to review in SPS' upcoming fuel reconciliation case.
New Mexico	The NMPRC approved SPS' requested fuel mechanism variance to permit recovery over 24 months with no financing charge (subject to NMPRC review).

Table of Contents

Public Utility Regulation

The FERC and state and local regulatory commissions regulate SPS. SPS is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in utility rates through commission filings. Changes in operating costs can affect SPS' financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2020 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2021 New Mexico Electric Rate Case	$88	January 2021	Pending
2021 Texas Electric Rate Case	$143	February 2021	Pending

Additional Information:

2021 New Mexico Electric Rate Case — In January 2021, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $88 million. SPS' net rate increase to New Mexico customers is expected to be approximately $48 million, or 10%, as a result of offsetting fuel cost reductions and PTCs from the Sagamore wind project. PTCs are being credited to customers through the fuel clause.

The request is based on a historic test year ended Sept. 30, 2020, including expected capital additions through Feb. 28, 2021, a ROE of 10.35%, an equity ratio of 54.72% and retail rate base of approximately $1.9 billion.

The request includes the effect of approximately 400 MW of reduced peak load in 2021 from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk coal-fired power plant (from 2037 to 2032) and the coal handling assets at the Harrington facility (to 2024).

The procedural schedule is expected to be as follows:

- Staff and intervenor testimony — May 17, 2021.
- Rebuttal testimony — June 9, 2021.
- Deadline to file stipulation — June 23, 2021.
- Public hearing or hearing on stipulation — July 26 - Aug. 6, 2021.
- End of nine month suspension — Nov. 3, 2021.

A NMPRC decision and implementation of final rates is anticipated in the fourth quarter of 2021.

2021 Texas Electric Rate Case — In February 2021, SPS filed an electric rate case with the PUCT and its municipalities with original rate jurisdiction seeking an increase in base rates of approximately $143 million. SPS' net rate increase to Texas customers is expected to be approximately $74 million, or 9.2%, as a result of offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is based on an ROE of 10.35%, an equity ratio of 54.60% (based on actual capital structure), a Texas retail rate base of approximately $3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020.

The request includes the effect of losing approximately 400 MW from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk power plant (from 2037 to 2032) and the coal handling assets of the Harrington facility (to 2024).

The procedural schedule is expected to be as follows:

- Intervenor testimony — Aug. 13, 2021.
- Staff testimony — Aug. 20, 2021.
- Rebuttal testimony — Sept. 15, 2021.
- Public hearing — Oct. 18 - Oct. 28, 2021.

Once final rates are approved, a surcharge will be requested from March 15, 2021 through the effective date of new base rates. A PUCT decision is expected in the first quarter of 2022.

Texas State ROFR Litigation — In May 2019, the Governor signed a ROFR bill into law, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. In February 2020, the federal court complaint was dismissed by the district court. In March 2020, the district court ruling was appealed to the Fifth Circuit. A decision is pending.

New Mexico FPPCAC Continuation — In December 2020, the Hearing Examiner recommended the NMPRC approve SPS' request for the continued use of the FPPCAC and the reconciliation of its fuel costs for the reporting period (September 2015 through June 2019). Additionally, the Hearing Examiner recommended the NMPRC deny the proposed Annual Deferred Fuel Balance True-Up. The proposed true-up is designed to maintain the Deferred Fuel and Purchased Power balance within a bandwidth of plus or minus 5% of annual New Mexico fuel and purchased power costs. In February 2021, the NMPRC approved the Hearing Examiner's recommended decision without modification.

Environmental

Environmental Regulation

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for greenhouse gas reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision, if not successfully appealed or reconsidered, would allow the EPA to proceed with alternate regulation of coal-fired power plants. If the new rules require additional investment, SPS believes, based on prior state commission practices, that the cost of these initiatives or replacement generation would be recoverable through rates.

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

Table of Contents

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of March 31, 2021, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.
For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2020, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation, dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	3.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Southwestern Public Service Company

April 29, 2021

By: /s/ JEFFREY S. SAVAGE

Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ BRIAN J. VAN ABEL

Brian J. Van Abel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

2021 Form 10-Q

For the Quarterly Period Ended

June 30, 2021

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2021

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-03789

Southwestern Public Service Company

(Exact name of registrant as specified in its charter)

New Mexico	**75-0575400**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
790 South Buchanan Street Amarillo Texas	**79101**
(Address of principal executive offices)	(Zip Code)

(303) 571-7511

(Registrant's telephone number, including area code)

N/A

(Former name, former address and former fiscal year, if changed since last report)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 29, 2021
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

TABLE OF CONTENTS

This Form 10-Q is filed by Southwestern Public Service Company, a New Mexico corporation (SPS). SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the Securities and Exchange Commission. This report should be read in its entirety.

Table of Contents

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries
Federal and State Regulatory Agencies	
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission
Electric, Purchased Gas and Resource Adjustment Clauses	
DSM	Demand side management
Other	
ASC	FASB Accounting Standards Codification
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	United States generally accepted accounting principles
IPP	Independent power producing entity
IRP	Integrated Resource Plan
LP&L	Lubbock Power and Light
LLC	Limited liability company
NOL	Net operating loss
NOPR	Notice of Proposed Rulemaking
O&M	Operating and maintenance
OATT	Open access transmission tariff
PFAS	Per- and PolyFluoroAlkyl Substances
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
VIE	Variable interest entity
Measurements	
MW	Megawatts

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impacts on our results of operations, financial condition and cash flows or resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly Report on Form 10-Q and in other filings with the SEC (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2020, and subsequent filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

Table of Contents

PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended June 30		Six Months Ended June 30	
	2021	2020	2021	2020
Operating revenues	$ 498	$ 423	$ 1,432	$ 818
Operating expenses				
Electric fuel and purchased power	252	199	945	386
Operating and maintenance expenses	71	58	142	128
Demand side management expenses	4	4	8	8
Depreciation and amortization	78	64	156	123
Taxes (other than income taxes)	18	18	39	40
Total operating expenses	423	343	1,290	685
Operating income	75	80	142	133
Other income (expense), net	—	—	1	(2)
Allowance for funds used during construction — equity	1	8	2	14
Interest charges and financing costs				
Interest charges — includes other financing costs of $1 , $1, $2 and $2, respectively	29	25	59	50
Allowance for funds used during construction — debt	(1)	(3)	(1)	(6)
Total interest charges and financing costs	28	22	58	44
Income before income taxes	48	66	87	101
Income tax benefit	(20)	(6)	(39)	(13)
Net income	$ 68	$ 72	$ 126	$ 114

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Six Months Ended June 30	
	2021	2020
Operating activities		
Net income	$ 126	$ 114
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	158	124
Deferred income taxes	(39)	11
Allowance for equity funds used during construction	(2)	(14)
Provision for bad debts	3	3
Changes in operating assets and liabilities:		
Accounts receivable	(28)	(6)
Accrued unbilled revenues	(20)	(4)
Inventories	(16)	(16)
Prepayments and other	21	(4)
Accounts payable	6	4
Net regulatory assets and liabilities	(96)	(32)
Other current liabilities	1	(8)
Pension and other employee benefit obligations	(16)	(15)
Other, net	(2)	3
Net cash provided by operating activities	96	160
Investing activities		
Utility capital/construction expenditures	(334)	(520)
Investments in utility money pool arrangement	(83)	(4)
Repayments from utility money pool arrangement	83	4
Net cash used in investing activities	(334)	(520)
Financing activities		
Repayments of short-term borrowings, net	(250)	—
Proceeds from issuance of long-term debt, net	247	343
Borrowings under utility money pool arrangement	324	711
Repayments under utility money pool arrangement	(261)	(711)
Capital contributions from parent	304	436
Dividends paid to parent	(130)	(129)
Net cash provided by financing activities	234	650
Net change in cash, cash equivalents and restricted cash	(4)	290
Cash, cash equivalents and restricted cash at beginning of period	6	16
Cash, cash equivalents and restricted cash at end of period	$ 2	$ 306
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (54)	$ (40)
Cash received for income taxes, net	17	5
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 39	$ 108
Inventory transfers to property, plant and equipment	6	14
Allowance for equity funds used during construction	2	14

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	June 30, 2021	Dec. 31, 2020
Assets		
Current assets		
Cash and cash equivalents	$ 2	$ 6
Accounts receivable, net	116	94
Accounts receivable from affiliates	11	9
Accrued unbilled revenues	135	114
Inventories	46	36
Regulatory assets	166	76
Derivative instruments	44	10
Prepaid taxes	7	18
Prepayments and other	10	20
Total current assets	537	383
Property, plant and equipment, net	7,756	7,603
Other assets		
Regulatory assets	369	357
Derivative instruments	8	9
Operating lease right-of-use assets	478	492
Other	16	15
Total other assets	871	873
Total assets	$ 9,164	$ 8,859
Liabilities and Equity		
Current liabilities		
Short-term debt	$ —	$ 250
Borrowings under utility money pool arrangement	63	—
Accounts payable	176	198
Accounts payable to affiliates	16	17
Regulatory liabilities	85	57
Taxes accrued	50	54
Accrued interest	31	29
Dividends payable to parent	55	54
Derivative instruments	4	4
Operating lease liabilities	29	28
Other	25	25
Total current liabilities	534	716
Deferred credits and other liabilities		
Deferred income taxes	697	725
Regulatory liabilities	718	718
Asset retirement obligations	114	112
Derivative instruments	7	9
Pension and employee benefit obligations	27	42
Operating lease liabilities	449	463
Other	9	12
Total deferred credits and other liabilities	2,021	2,081
Commitments and contingencies		
Capitalization		
Long-term debt	3,012	2,764
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at June 30, 2021 and Dec. 31, 2020, respectively	—	—
Additional paid in capital	3,094	2,790
Retained earnings	504	509
Accumulated other comprehensive loss	(1)	(1)
Total common stockholder's equity	3,597	3,298
Total liabilities and equity	$ 9,164	$ 8,859

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended June 30, 2021 and 2020						
Balance at March 31, 2020	100	$ —	$ 2,383	$ 502	$ (1)	$ 2,884
Net income				72		72
Dividends declared to parent				(55)		(55)
Contributions of capital by parent			404			404
Balance at June 30, 2020	100	$ —	$ 2,787	$ 519	$ (1)	$ 3,305
Balance at March 31, 2021	100	$ —	$ 3,094	$ 515	$ (1)	$ 3,608
Net income				68		68
Dividends declared to parent				(79)		(79)
Balance at June 30, 2021	100	$ —	$ 3,094	$ 504	$ (1)	$ 3,597

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Six Months Ended June 30, 2021 and 2020						
Balance at Dec. 31, 2019	100	$ —	$ 2,351	$ 535	$ (1)	$ 2,885
Net income				114		114
Dividends declared to parent				(130)		(130)
Contributions of capital by parent			436			436
Balance at June 30, 2020	100	$ —	$ 2,787	$ 519	$ (1)	$ 3,305
Balance at Dec. 31, 2020	100	$ —	$ 2,790	$ 509	$ (1)	$ 3,298
Net income				126		126
Dividends declared to parent				(131)		(131)
Contributions of capital by parent			304			304
Balance at June 30, 2021	100	$ —	$ 3,094	$ 504	$ (1)	$ 3,597

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with GAAP, the financial position of SPS as of June 30, 2021 and Dec. 31, 2020; the results of its operations, including the components of net income and changes in stockholder's equity for the three and six months ended June 30, 2021 and 2020; and its cash flows for the six months ended June 30, 2021 and 2020.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2021 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2020 balance sheet information has been derived from the audited 2020 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020.

These notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020, filed with the SEC on Feb. 17, 2021. Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

SPS implemented the guidance using a modified-retrospective approach, recognizing an immaterial cumulative effect charge (after tax) to retained earnings on Jan. 1, 2020. The Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	June 30, 2021	Dec. 31, 2020
Accounts receivable, net		
Accounts receivable	$ 126	$ 102
Less allowance for bad debts	(10)	(8)
Accounts receivable, net	$ 116	$ 94

(Millions of Dollars)	June 30, 2021	Dec. 31, 2020
Inventories		
Materials and supplies	$ 28	$ 27
Fuel	18	9
Total inventories	$ 46	$ 36

(Millions of Dollars)	June 30, 2021	Dec. 31, 2020
Property, plant and equipment, net		
Electric plant	$ 9,418	$ 9,229
Plant to be retired [(a)]	308	316
CWIP	231	146
Total property, plant and equipment	9,957	9,691
Less accumulated depreciation	(2,201)	(2,088)
Property, plant and equipment, net	$ 7,756	$ 7,603

(a) Includes expected retirement of Tolk and conversion of Harrington to natural gas.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	63	—
Average amount outstanding	6	43
Maximum amount outstanding	94	100
Weighted average interest rate, computed on a daily basis	0.02 %	0.54 %
Weighted average interest rate at period end	0.02	N/A

Commercial Paper — Commercial paper outstanding for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	—	250
Average amount outstanding	—	44
Maximum amount outstanding	—	250
Weighted average interest rate, computed on a daily basis	N/A	1.11 %
Weighted average interest rate at period end	N/A	0.29

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. At both June 30, 2021 and Dec. 31, 2020, there were $2 million of letters of credit outstanding under the credit facility. Amounts approximate their fair value and are subject to fees.

Table of Contents

Revolving Credit Facility — In order to issue its commercial paper, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper exceeding available capacity under this credit facility. The credit facility provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of June 30, 2021, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 2	$ 498

(a) Expires in June 2024.
(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of June 30, 2021 and Dec. 31, 2020.

Long-Term Borrowings

During the six months ended June 30, 2021, SPS issued $250 million of 3.15% first mortgage bonds due 2050.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consisted of the following:

	Three Months Ended June 30	
(Millions of Dollars)	**2021**	**2020**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 85	$ 85
C&I	201	164
Other	10	8
Total retail	296	257
Wholesale	118	82
Transmission	72	76
Other	2	—
Total revenue from contracts with customers	488	415
Alternative revenue and other	10	8
Total revenues	$ 498	$ 423

	Six Months Ended June 30	
(Millions of Dollars)	**2021**	**2020**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 176	$ 158
C&I	389	333
Other	19	16
Total retail	584	507
Wholesale	676	155
Transmission	143	139
Other	5	1
Total revenue from contracts with customers	1,408	802
Alternative revenue and other	24	16
Total revenues	$ 1,432	$ 818

6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2020 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

Difference between the statutory rate and ETR:

	Six Months Ended June 30	
	2021	**2020 [(a)]**
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.6	2.3
Decreases in tax from:		
Wind PTCs	(61.6)	(26.7)
Plant regulatory differences [(b)]	(5.0)	(6.4)
Amortization of excess nonplant deferred taxes	(1.2)	(0.9)
Other (net)	(0.6)	(2.2)
Effective income tax rate	(44.8)%	(12.9)%

(a) Prior periods have been restated to conform to current year presentation.
(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

Federal Audits — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Years	Expiration
2014 — 2016	January 2022
2017	September 2021

Additionally, the statute of limitations related to a federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of June 30, 2021, SPS' earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2012. In April 2021, Texas began an audit of tax years 2016 - 2019. No material adjustments have been proposed.

Unrecognized Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the timing of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	June 30, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	$ 3	$ 3
Unrecognized tax benefit — Temporary tax positions	4	4
Total unrecognized tax benefit	$ 7	$ 7

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	June 30, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	$ (7)	$ (6)

Table of Contents

As the IRS audit resumes and state audit progresses, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $5 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	June 30, 2021	Dec. 31, 2020
(Payable) receivable for interest related to unrecognized tax benefits at beginning of period	$ (1)	$ 1
Interest expense related to unrecognized tax benefits	—	(2)
Payable for interest related to unrecognized tax benefits at end of period	$ (1)	$ (1)

No amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 2021 or Dec. 31, 2020.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as FTRs, purchased from SPP. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of June 30, 2021, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Amounts in Millions [(a)]	June 30, 2021	Dec. 31, 2020
Megawatt hours of electricity	18	5

(a) Amounts are not reflective of net positions in the underlying commodities.

Table of Contents

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

At June 30, 2021, two of the eight most significant counterparties for these activities, comprising $13 million, or 36%, of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Five of the eight most significant counterparties, comprising $24 million, or 64%, of this credit exposure, were not rated by external ratings agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were no gains or immaterial losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three and six months ended June 30, 2021 and 2020, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains of $8 million and $10 million recognized for the three and six months ended June 30, 2021, respectively, which were reclassified as regulatory assets or liabilities. There were $3 million of pre-tax net losses recognized for the three and six months ended June 30, 2020, respectively, which were reclassified as a regulatory assets or liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement losses of $4 million and gains of $11 million were recognized for the three and six months ended June 30, 2021, respectively, and were recorded to electric fuel and purchased power. Settlement gains of $2 million and $5 million were recognized for the three and six months ended June 30, 2020, respectively and were recorded to electric fuel and purchases power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three and six months ended June 30, 2021 and 2020.

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis:

	June 30, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 41	$ 41	$ —	$ 41	$ —	$ —	$ 7	$ 7	$ —	$ 7
Total current derivative assets	$ —	$ —	$ 41	$ 41	$ —	41	$ —	$ —	$ 7	$ 7	$ —	7
PPAs (b)						3						3
Current derivative instruments						$ 44						$ 10
Noncurrent derivative assets												
PPAs (b)						8						9
Noncurrent derivative instruments						$ 8						$ 9

	June 30, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
Other derivative instruments:												
PPAs (b)						$ 4						$ 4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs (b)						$ 7						$ 9
Noncurrent derivative instruments						$ 7						$ 9

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at June 30, 2021 and Dec. 31, 2020. At June 30, 2021 and Dec. 31, 2020, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Table of Contents

Changes in Level 3 commodity derivatives for the three and six months ended June 30, 2021 and 2020:

(Millions of Dollars)	Three Months Ended June 30 2021	2020
Balance at April 1	$ 12	$ 16
Purchases	9	9
Settlements	(12)	(12)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	32	3
Balance at June 30	$ 41	$ 16

(Millions of Dollars)	Six Months Ended June 30 2021	2020
Balance at Jan. 1	$ 7	$ 12
Purchases	9	21
Settlements	(21)	(17)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	46	—
Balance at June 30	$ 41	$ 16

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and six months ended June 30, 2021 and 2020.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	June 30, 2021		Dec. 31, 2020	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 3,012	$ 3,482	$ 2,764	$ 3,381

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of June 30, 2021 and Dec. 31, 2020 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2021	2020	2021	2020
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 3	$ 2	$ —	$ —
Interest cost [a]	4	5	—	—
Expected return on plan assets [a]	(8)	(7)	(1)	—
Amortization of net loss [a]	3	3	—	—
Net periodic benefit cost (credit)	$ 2	$ 3	$ (1)	$ —
Effects of regulation	1	—	—	—
Net benefit cost (credit) recognized for financial reporting	$ 3	$ 3	$ (1)	$ —

	Six Months Ended June 30			
	2021	2020	2021	2020
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 5	$ 5	$ —	$ —
Interest cost [a]	8	9	—	1
Expected return on plan assets [a]	(15)	(15)	(1)	(1)
Amortization of net loss [a]	7	7	—	—
Net periodic benefit cost (credit)	$ 5	$ 6	$ (1)	$ —
Effects of regulation	1	1	—	—
Net benefit cost (credit) recognized for financial reporting	$ 6	$ 7	$ (1)	$ —

(a) The components of net periodic cost other than the service cost component are included in the line item "Other income (expense), net" in the statements of income or capitalized on the balance sheets as a regulatory asset.

In January 2021, contributions of $125 million were made across four of Xcel Energy's pension plans, of which $14 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2021.

9. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. SPS has intervened in both appeals in support of the FERC. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

Table of Contents

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. This appeal is stayed pending the outcome of the separate appeal initiated in 2020 by Oklahoma Gas & Electric and SPP.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include the costs of the GridLiance High Plains, LLC facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT. SPP's proposed tariff changes resulted in an increase in the annual transmission revenue requirement of $10 million per year, with $6 million allocated to SPS' retail customers. The remaining $4 million would be paid by other wholesale loads in the SPS rate zone. On March 16, 2020, GridLiance also filed additional rate increases for 2020 which would raise their annual revenue requirement to $14 million, with approximately $9 million allocated to SPS' retail customers.

In August 2020, FERC issued an order on a question certified by the hearing judge for the FERC's review, in which FERC made certain findings in SPS' favor regarding the legal standard that applies to the ongoing hearing proceeding. In November 2020, FERC denied GridLiance's request for rehearing of the August 2020 order. In December 2020, GridLiance filed a petition for review at the D.C. Circuit of the August 2020 and November 2020 orders on the certified question.

The hearing portion of this proceeding was concluded in September 2020. The initial post-hearing brief was filed in October 2020. On June 3, 2021, the Administrative Law Judge issued a recommended decision, subject to FERC approval, that supports that the GridLiance facilities are transmission facilities and eligible for rate recovery under the SPP OATT. The FERC will then rule on the judge's decision and either sustain it, overturn it, or order further proceedings. SPS has incurred approximately $19 million in associated charges as of June 30, 2021.

Contract Termination — SPS and LP&L have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the ERCOT (expected in 2023) or, absent a move by LP&L to ERCOT, upon LP&L's election. The settlement agreement requires LP&L to pay SPS $78 million (lump sum or annual installments), to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The settlement agreement is subject to approval by the PUCT and FERC.

FERC NOPR on ROE Incentive Adders — In April 2021, the FERC issued a NOPR proposing to limit collection of ROE incentive adders for RTO membership to the first three years after an entity begins participation in an RTO. If adopted as a final rule, following a comment period expected to be complete by the end of 2021 or 2022, SPS would prospectively discontinue charging their current 0.5% ROE incentive adders. Amounts related to a discontinuance of the adder would ultimately be offset by an increase in retail rates, following future rate cases.

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites — SPS is remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

	Three Months Ended June 30	
(Millions of Dollars)	**2021**	**2020**
Operating leases		
PPA capacity payments	$ 13	$ 12
Other operating leases [(a)]	1	1
Total operating lease expense [(b)]	$ 14	$ 13

(a) Includes immaterial short-term lease expense for 2021 and 2020.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

	Six Months Ended June 30	
(Millions of Dollars)	**2021**	**2020**
Operating leases		
PPA capacity payments	$ 26	$ 23
Other operating leases [(a)]	2	2
Total operating lease expense [(b)]	$ 28	$ 25

(a) Includes short-term lease expense of $1 million for 2021 and 2020, respectively.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating leases as of June 30, 2021:

(Millions of Dollars)	**PPA Operating Leases**	**Other Operating Leases**	**Total Operating Leases**
Total minimum obligation	$ 567	$ 57	$ 624
Interest component of obligation	(130)	(16)	(146)
Present value of minimum obligation	$ 437	$ 41	478
Less current portion			(29)
Noncurrent operating and finance lease liabilities			$ 449

VIEs

Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that it purchases. These specific PPAs create a variable interest in the IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs at both June 30, 2021 and Dec. 31, 2020 with entities that have been determined to be VIEs. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

Table of Contents

ITEM 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for SPS is omitted per conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in General Instruction H(2)(a) of Form 10-Q for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as, electric margin and ongoing earnings.

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, O&M expenses, DSM expenses, depreciation and amortization and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $126 million for the six months ended June 30, 2021 compared with approximately $114 million for the prior year, reflecting higher electric margin (capital investment recovery and regulatory outcomes), partially offset by increased depreciation and O&M expenses.

Electric Margin

Electric revenues and fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses.

Electric revenues and margin:

	Six Months Ended June 30	
(Millions of Dollars)	**2021**	**2020**
Electric revenues [(a)]	$ 1,432	$ 818
Electric fuel and purchased power [(a)]	(945)	(386)
Electric margin	$ 487	$ 432

(a) The increase in revenue and electric fuel and purchased power is primarily due to Winter Storm Uri, resulting in higher fuel prices, as well as additional long-term energy and SPP market purchases.

Changes in electric margin:

(Millions of Dollars)	**Six Months Ended June 30, 2021 vs. 2020**
Regulatory rate outcomes (Texas and New Mexico)	$ 45
Sales and demand	10
Wholesale transmission revenue (net)	9
Proprietary commodity trading, net of sharing - Winter Storm Uri	4
PTCs flowed back to customers (offset by lower ETR)	(27)
Other (net)	14
Total increase in electric margin	$ 55

Non-Fuel Operating Expense and Other Items

Depreciation and Amortization — Depreciation and amortization increased $33 million, or 26.8%, year-to-date. The increase was primarily due to the Sagamore wind farm being placed in service in December 2020, in addition to system expansion. The increase is also due to new FERC transmission rates applied in March 2020 and implementation of new depreciation rates in both New Mexico and Texas as part of regulatory outcomes in 2020.

O&M Expenses — O&M expenses increased $14 million, or 10.9%, year-to-date. The increase was primarily due to expenses related to new wind farms and software infrastructure & security costs, partially offset by continuous improvement initiatives. Timing impacts also occurred throughout 2020 due to cost control initiatives to mitigate the adverse impact of COVID-19 on sales.

AFUDC, Equity and Debt — AFUDC decreased $17 million for the first six months of 2021, primarily due to construction of the Sagamore wind farm and various transmission construction projects during 2020.

Income Taxes — Income tax benefit increased $26 million for the first six months of 2021. The increase was primarily driven by an increase in wind PTCs. Wind PTCs are largely credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

See Note 6 to the financial statements for further information.

Other

Winter Storm Uri

In February 2021, the central portion of the United States experienced a major winter storm (Winter Storm Uri). Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation across the region. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity.

Table of Contents

As a result of the extremely high market prices, SPS incurred net natural gas, fuel and purchased energy costs of approximately $100 million (largely deferred as regulatory assets) in the first quarter. Certain energy transactions are subject to final/settlement calculation adjustments, including the impacts of credit losses shared among market participants.

Regulatory Overview — SPS has electric fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, February cost increases were deferred for future recovery with recovery proposed over a period of up to two years to significantly mitigate the impact to customer bills.

The following proceedings have been initiated:

Jurisdiction	Regulatory Status
Texas	SPS filed for a surcharge in the second quarter to recover $62 million in fuel costs over 24 months, subject to revision due to re-settlements. Prudence of costs will be subject to review in SPS' upcoming fuel reconciliation case.
New Mexico	The NMPRC approved SPS' request to recover $26 million of fuel costs over 24 months with no financing charge, subject to revision due to re-settlements and NMPRC review.

Supply Chain and Capital Expenditures

SPS' ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Overall, as a result of COVID-19, manufacturing processes have experienced disruptions related to scarcity of raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, storms and labor shortages. The Company continues to monitor the availability of materials and seek alternative suppliers as necessary.

Public Utility Regulation

The FERC and state and local regulatory commissions regulate SPS. SPS is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in utility rates through commission filings. Changes in operating costs can affect SPS' financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2020 and in Item 2 of SPS' Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2021, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2021 New Mexico Electric Rate Case	$88	January 2021	Pending
2021 Texas Electric Rate Case	$143	February 2021	Pending

Additional Information:

2021 New Mexico Electric Rate Case — In January 2021, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $88 million. SPS' net rate increase to New Mexico customers is expected to be approximately $48 million, or 10%, as a result of the offsetting fuel cost reductions and PTCs from the Sagamore wind project. PTCs are credited to customers through the fuel clause. In June 2021, SPS revised its requested base rate increase to $84 million.

The request was based on a historic test year ended Sept. 30, 2020, including expected capital additions through Feb. 28, 2021, a ROE of 10.35%, an equity ratio of 54.72% and a retail rate base of approximately $1.9 billion.

In June 2021, SPS and various parties filed an uncontested comprehensive stipulation, which includes:

- Base rate revenue increase of $62 million.
- ROE of 9.35% for purposes of filings related to (1) the Hale and Sagamore wind projects; and (2) reconciliation of the settlement revenue requirement.
- Equity ratio of 54.72%.
- Increase in depreciation expense of $6 million. This includes a change in the depreciable lives of the Tolk power plant to 2032 and coal handling assets at the Harrington facility to 2024.

A public hearing is scheduled for July 26 - Aug. 6, 2021. A NMPRC decision and implementation of final rates is anticipated in the fourth quarter of 2021.

2021 Texas Electric Rate Case — In February 2021, SPS filed an electric rate case with the PUCT and its municipalities seeking an increase in base rates of approximately $143 million. SPS' net rate increase to Texas customers is expected to be approximately $74 million, or 9.2%, as a result of the offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is based on a ROE of 10.35%, an equity ratio of 54.60%, a rate base of approximately $3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020.

The request includes the effect of losing approximately 400 MW from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk power plant (from 2037 to 2032) and coal handling assets at the Harrington facility (to 2024).

Procedural schedule expected to be as follows:

- Intervenor testimony — Aug. 13, 2021.
- Staff testimony — Aug. 20, 2021.
- Rebuttal testimony — Sept. 15, 2021.
- Public hearing — Oct. 18 - Oct. 28, 2021.

The PUCT set current rates as temporary as of March 15, 2021. Once final rates are approved, a surcharge will be requested from March 15, 2021 through the effective date of new base rates. A PUCT decision is expected in the first quarter of 2022.

New Mexico Integrated Resource Plan — In July 2021, SPS filed an IRP with the NMPRC, as required every three years. SPS is forecasting sufficient resources through 2025. A projected capacity deficit was identified totaling approximately 174 MW in 2031, increasing to 4,194 MW by 2041.

SPS has provided a number of alternatives, including a proposed portfolio of resources incorporating the addition of wind generation, solar generation, firm and dispatchable peaking generation, and purchased power agreements. SPS will continue to evaluate other options including energy storage and emerging technologies, taking into consideration cost-effectiveness. The IRP is subject to public comment and potential public hearings and will ultimately be reviewed by the NMPRC for approval.

Environmental

Affordable Clean Energy

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for greenhouse gas reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision, if not successfully appealed or reconsidered, would allow the EPA to proceed with alternate regulation of coal-fired power plants. If the new rules require additional investment, SPS believes, based on prior state commission practices, that the cost of these initiatives or replacement generation would be recoverable through rates.

Emerging Regulation

New regulations and legislation are being considered to regulate PFAS in drinking water, water discharges, commercial products, wastes, and other areas. PFAS are man-made chemicals found in many consumer products that can persist and accumulate in the environment. These chemicals have received heightened attention by environmental regulators. Increased regulation of PFAS and other emerging contaminants at the federal, state, and local level could have a potential adverse effect on our operations but at this time, it is uncertain what impact, if any, there will be on our results of operations, financial condition or cash flows. SPS will continue to monitor these regulatory developments and their potential impact on its operations

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of June 30, 2021, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2020, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

Table of Contents

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation, dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	3.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Southwestern Public Service Company

July 29, 2021	By:	/s/ JEFFREY S. SAVAGE
		Jeffrey S. Savage
		Senior Vice President, Controller
		(Principal Accounting Officer)
		/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer and Director
		(Principal Financial Officer)

2021 Form 10-Q

For the Quarterly Period Ended

September 30, 2021

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended Sept. 30, 2021

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-03789

Southwestern Public Service Company

(Exact name of registrant as specified in its charter)

New Mexico	**75-0575400**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
790 South Buchanan Street Amarillo Texas	**79101**
(Address of principal executive offices)	(Zip Code)

(303) 571-7511

(Registrant's telephone number, including area code)

N/A

(Former name, former address and former fiscal year, if changed since last report)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at Oct. 28, 2021
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

TABLE OF CONTENTS

This Form 10-Q is filed by Southwestern Public Service Company, a New Mexico corporation (SPS). SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the Securities and Exchange Commission. This report should be read in its entirety.

Table of Contents

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies	
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses	
DSM	Demand side management

Other	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	United States generally accepted accounting principles
IPP	Independent power producing entity
LP&L	Lubbock Power and Light
LLC	Limited liability company
NOL	Net operating loss
NOPR	Notice of Proposed Rulemaking
O&M	Operating and maintenance
OATT	Open access transmission tariff
PFAS	Per- and PolyFluoroAlkyl Substances
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
VIE	Variable interest entity

Measurements	
MW	Megawatts

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed in SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2020 and subsequent filings with the SEC, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints, and their impact on capital expenditures and/or the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

Table of Contents

PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2021	2020	2021	2020
Operating revenues	$ 575	$ 615	$ 2,007	$ 1,434
Operating expenses				
Electric fuel and purchased power	250	240	1,195	627
Operating and maintenance expenses	66	78	208	207
Demand side management expenses	5	5	13	12
Depreciation and amortization	71	100	227	223
Taxes (other than income taxes)	20	29	59	68
Total operating expenses	412	452	1,702	1,137
Operating income	163	163	305	297
Other income (expense), net	—	—	1	(2)
Allowance for funds used during construction — equity	1	10	3	24
Interest charges and financing costs				
Interest charges — includes other financing costs of $1, $1, $3 and $3, respectively	28	39	87	89
Allowance for funds used during construction — debt	—	(4)	(1)	(10)
Total interest charges and financing costs	28	35	86	79
Income before income taxes	136	138	223	240
Income tax expense (benefit)	2	11	(37)	(2)
Net income	$ 134	$ 127	$ 260	$ 242

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Nine Months Ended Sept. 30	
	2021	2020
Operating activities		
Net income	$ 260	$ 242
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	229	225
Deferred income taxes	(31)	25
Allowance for equity funds used during construction	(3)	(24)
Provision for bad debts	6	5
Changes in operating assets and liabilities:		
Accounts receivable	(66)	(31)
Accrued unbilled revenues	(20)	(4)
Inventories	(14)	(24)
Prepayments and other	21	(14)
Accounts payable	6	(3)
Net regulatory assets and liabilities	(113)	(96)
Other current liabilities	19	15
Pension and other employee benefit obligations	(16)	(15)
Other, net	(2)	3
Net cash provided by operating activities	276	304
Investing activities		
Utility capital/construction expenditures	(446)	(845)
Investments in utility money pool arrangement	(83)	(4)
Repayments from utility money pool arrangement	83	4
Net cash used in investing activities	(446)	(845)
Financing activities		
Repayments of short-term borrowings, net	(232)	—
Proceeds from issuance of long-term debt, net	247	343
Borrowings under utility money pool arrangement	539	721
Repayments under utility money pool arrangement	(439)	(711)
Capital contributions from parent	304	435
Dividends paid to parent	(254)	(257)
Net cash provided by financing activities	165	531
Net change in cash, cash equivalents and restricted cash	(5)	(10)
Cash, cash equivalents and restricted cash at beginning of period	6	16
Cash, cash equivalents and restricted cash at end of period	$ 1	$ 6
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (75)	$ (69)
Cash received for income taxes, net	19	4
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 39	$ 111
Inventory transfers to property, plant and equipment	6	22
Allowance for equity funds used during construction	3	24

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	Sept. 30, 2021	Dec. 31, 2020
Assets		
Current assets		
Cash and cash equivalents	$ 1	$ 6
Accounts receivable, net	149	94
Accounts receivable from affiliates	12	9
Accrued unbilled revenues	134	114
Inventories	44	36
Regulatory assets	173	76
Derivative instruments	40	10
Prepaid taxes	3	18
Prepayments and other	16	20
Total current assets	572	383
Property, plant and equipment, net	7,790	7,603
Other assets		
Regulatory assets	394	357
Derivative instruments	7	9
Operating lease right-of-use assets	471	492
Other	14	15
Total other assets	886	873
Total assets	$ 9,248	$ 8,859
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 18	$ 250
Borrowings under utility money pool arrangement	100	—
Accounts payable	182	198
Accounts payable to affiliates	14	17
Regulatory liabilities	84	57
Taxes accrued	59	54
Accrued interest	38	29
Dividends payable to parent	53	54
Derivative instruments	4	4
Operating lease liabilities	29	28
Other	26	25
Total current liabilities	607	716
Deferred credits and other liabilities		
Deferred income taxes	714	725
Regulatory liabilities	712	718
Asset retirement obligations	115	112
Derivative instruments	7	9
Pension and employee benefit obligations	26	42
Operating lease liabilities	441	463
Other	8	12
Total deferred credits and other liabilities	2,023	2,081
Commitments and contingencies		
Capitalization		
Long-term debt	3,012	2,764
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at Sept. 30, 2021 and Dec. 31, 2020, respectively	—	—
Additional paid in capital	3,091	2,790
Retained earnings	516	509
Accumulated other comprehensive loss	(1)	(1)
Total common stockholder's equity	3,606	3,298
Total liabilities and equity	$ 9,248	$ 8,859

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended Sept. 30, 2021 and 2020						
Balance at June 30, 2020	100	$ —	$ 2,787	$ 519	$ (1)	$ 3,305
Net income				127		127
Dividends declared to parent				(136)		(136)
Balance at Sept. 30, 2020	100	$ —	$ 2,787	$ 510	$ (1)	$ 3,296
Balance at June 30, 2021	100	$ —	$ 3,094	$ 504	$ (1)	$ 3,597
Net income				134		134
Dividends declared to parent				(122)		(122)
Contributions of capital by parent			(3)			(3)
Balance at Sept. 30, 2021	100	$ —	$ 3,091	$ 516	$ (1)	$ 3,606

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Nine Months Ended Sept. 30, 2021 and 2020						
Balance at Dec. 31, 2019	100	$ —	$ 2,351	$ 535	$ (1)	$ 2,885
Net income				242		242
Dividends declared to parent				(267)		(267)
Contributions of capital by parent			436			436
Balance at Sept. 30, 2020	100	$ —	$ 2,787	$ 510	$ (1)	$ 3,296
Balance at Dec. 31, 2020	100	$ —	$ 2,790	$ 509	$ (1)	$ 3,298
Net income				260		260
Dividends declared to parent				(253)		(253)
Contributions of capital by parent			301			301
Balance at Sept. 30, 2021	100	$ —	$ 3,091	$ 516	$ (1)	$ 3,606

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with GAAP, the financial position of SPS as of Sept. 30, 2021 and Dec. 31, 2020; the results of SPS' operations, including the components of net income and changes in stockholder's equity for the three and nine months ended Sept. 30, 2021 and 2020; and SPS' cash flows for the nine months ended Sept. 30, 2021 and 2020.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2021 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2020 balance sheet information has been derived from the audited 2020 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020.

Notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020, filed with the SEC on Feb. 17, 2021.

Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2020 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

SPS implemented the guidance using a modified-retrospective approach, recognizing an immaterial cumulative effect charge (after tax) to retained earnings on Jan. 1, 2020. The Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	Sept. 30, 2021	Dec. 31, 2020
Accounts receivable, net		
Accounts receivable	$ 160	$ 102
Less allowance for bad debts	(11)	(8)
Accounts receivable, net	$ 149	$ 94

(Millions of Dollars)	Sept. 30, 2021	Dec. 31, 2020
Inventories		
Materials and supplies	$ 29	$ 27
Fuel	15	9
Total inventories	$ 44	$ 36

(Millions of Dollars)	Sept. 30, 2021	Dec. 31, 2020
Property, plant and equipment, net		
Electric plant	$ 9,439	$ 9,229
Plant to be retired [(a)]	303	316
CWIP	285	146
Total property, plant and equipment	10,027	9,691
Less accumulated depreciation	(2,237)	(2,088)
Property, plant and equipment, net	$ 7,790	$ 7,603

(a) Includes expected retirement of Tolk and conversion of Harrington to natural gas.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	100	—
Average amount outstanding	78	43
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	0.05 %	0.54 %
Weighted average interest rate at period end	0.05	N/A

Commercial Paper — Commercial paper outstanding for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	18	250
Average amount outstanding	1	44
Maximum amount outstanding	18	250
Weighted average interest rate, computed on a daily basis	0.15 %	1.11 %
Weighted average interest rate at period end	0.13	0.29

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. At both Sept. 30, 2021 and Dec. 31, 2020, there were $2 million of letters of credit outstanding under the credit facility. Amounts approximate their fair value and are subject to fees.

Table of Contents

Revolving Credit Facility — In order to issue its commercial paper, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper exceeding available capacity under this credit facility. The credit facility provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of Sept. 30, 2021, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 20	$ 480

(a) Expires in June 2024.
(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of Sept. 30, 2021 and Dec. 31, 2020.

Long-Term Borrowings

During the nine months ended Sept. 30, 2021, SPS issued $250 million of 3.15% first mortgage bonds due May 1, 2050.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consisted of the following:

	Three Months Ended Sept. 30	
(Millions of Dollars)	**2021**	**2020**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 126	$ 121
C&I	241	219
Other	11	13
Total retail	378	353
Wholesale	109	109
Transmission	75	74
Other	2	1
Total revenue from contracts with customers	564	537
Alternative revenue and other	11	78
Total revenues	$ 575	$ 615

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2021**	**2020**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 302	$ 278
C&I	631	552
Other	30	30
Total retail	963	860
Wholesale	785	264
Transmission	218	212
Other	6	3
Total revenue from contracts with customers	1,972	1,339
Alternative revenue and other	35	95
Total revenues	$ 2,007	$ 1,434

6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2020 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

Difference between the statutory rate and ETR:

	Nine Months Ended Sept. 30	
	2021	**2020 [(a)]**
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.5	2.4
Decreases in tax from:		
Wind PTCs	(32.9)	(15.6)
Plant regulatory differences [(b)]	(4.9)	(6.2)
Amortization of excess nonplant deferred taxes	(1.1)	(0.8)
Other (net)	(1.2)	(1.6)
Effective income tax rate	(16.6)%	(0.8)%

(a) Prior periods have been restated to conform to current year presentation.
(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

Federal Audits — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Years	Expiration
2014 — 2016	December 2022
2018	September 2022

Additionally, the statute of limitations related to certain federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to a federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Sept. 30, 2021, SPS' earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2012. In April 2021, Texas began an audit of tax years 2016 - 2019. No material adjustments have been proposed.

Unrecognized Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the timing of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	Sept. 30, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	$ 4	$ 3
Unrecognized tax benefit — Temporary tax positions	4	4
Total unrecognized tax benefit	$ 8	$ 7

Table of Contents

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Sept. 30, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	$ (7)	$ (6)

As the Internal Revenue Service audit resumes and state audit progresses, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $5 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	Sept. 30, 2021	Dec. 31, 2020
(Payable) receivable for interest related to unrecognized tax benefits at beginning of period	$ (1)	$ 1
Interest expense related to unrecognized tax benefits	—	(2)
Payable for interest related to unrecognized tax benefits at end of period	$ (1)	$ (1)

No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2021 or Dec. 31, 2020.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as FTRs, purchased from SPP. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of Sept. 30, 2021, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Amounts in Millions [(a)]	Sept. 30, 2021	Dec. 31, 2020
Megawatt hours of electricity	12	5

(a) Amounts are not reflective of net positions in the underlying commodities.

Table of Contents

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts, prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

At Sept. 30, 2021, two of the eight most significant counterparties for these activities, comprising $11 million, or 29%, of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Five of the eight most significant counterparties, comprising $27 million, or 70%, of this credit exposure, were not rated by external ratings agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were no gains or immaterial losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three and nine months ended Sept. 30, 2021 and 2020.

Changes in the fair value of FTRs resulting in pre-tax net gains of $5 million and $15 million recognized for the three and nine months ended Sept. 30, 2021, respectively, which were reclassified as regulatory assets or liabilities. There were $3 million and $5 million of pre-tax net losses recognized for the three and nine months ended Sept. 30, 2020, respectively, which were reclassified as a regulatory assets or liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement losses of $4 million and gains of $13 million were recognized for the three and nine months ended Sept. 30, 2021, respectively, and were recorded to electric fuel and purchased power. Settlement gains of $2 million and $4 million were recognized for the three and nine months ended Sept. 30, 2020, respectively and were recorded to electric fuel and purchases power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2021 and 2020.

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis:

	Sept. 30, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 37	$ 37	$ —	$ 37	$ —	$ —	$ 7	$ 7	$ —	$ 7
Total current derivative assets	$ —	$ —	$ 37	$ 37	$ —	37	$ —	$ —	$ 7	$ 7	$ —	7
PPAs (b)						3						3
Current derivative instruments						$ 40						$ 10
Noncurrent derivative assets												
PPAs (b)						7						9
Noncurrent derivative instruments						$ 7						$ 9

	Sept. 30, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
Other derivative instruments:												
PPAs (b)						$ 4						$ 4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs (b)						$ 7						$ 9
Noncurrent derivative instruments						$ 7						$ 9

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Sept. 30, 2021 and Dec. 31, 2020. At Sept. 30, 2021 and Dec. 31, 2020, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Table of Contents

Changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2021 and 2020:

	Three Months Ended Sept. 30	
(Millions of Dollars)	2021	2020
Balance at July 1	$ 41	$ 16
Purchases	2	—
Settlements	(18)	(1)
Net transactions recorded during the period:		
Net gains (losses) recognized as regulatory assets and liabilities	12	(4)
Balance at Sept. 30	$ 37	$ 11

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2021	2020
Balance at Jan. 1	$ 7	$ 12
Purchases	11	21
Settlements	(39)	(18)
Net transactions recorded during the period:		
Net gains (losses) recognized as regulatory assets and liabilities	58	(4)
Balance at Sept. 30	$ 37	$ 11

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2021 and 2020.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	Sept. 30, 2021		Dec. 31, 2020	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 3,012	$ 3,478	$ 2,764	$ 3,381

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Sept. 30, 2021 and Dec. 31, 2020 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2021	2020	2021	2020
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 3	$ 2	$ —	$ —
Interest cost [(a)]	3	5	—	—
Expected return on plan assets [(a)]	(7)	(7)	—	—
Amortization of net loss [(a)]	4	3	—	—
Net periodic benefit cost	$ 3	$ 3	$ —	$ —
Effects of regulation	(1)	—	—	—
Net benefit cost recognized for financial reporting	$ 2	$ 3	$ —	$ —

	Nine Months Ended Sept. 30			
	2021	2020	2021	2020
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 8	$ 7	$ —	$ —
Interest cost [(a)]	11	13	—	1
Expected return on plan assets [(a)]	(22)	(22)	(1)	(1)
Amortization of net loss [(a)]	11	10	—	—
Net periodic benefit cost (credit)	$ 8	$ 8	$ (1)	$ —
Effects of regulation	—	2	—	—
Net benefit cost (credit) recognized for financial reporting	$ 8	$ 10	$ (1)	$ —

(a) The components of net periodic cost other than the service cost component are included in the line item "Other income (expense), net" in the statements of income or capitalized on the balance sheets as a regulatory asset.

In January 2021, contributions of $125 million were made across four of Xcel Energy's pension plans, of which $14 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2021.

9. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C. Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates.

Table of Contents

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. FERC has asked that this appeal be stayed until early 2022, in order to provide FERC with time to issue an order on SPS' April 2018 rehearing request. The D.C. Circuit appeal may resume after that FERC order is issued.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include the costs of the GridLiance High Plains, LLC facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT. SPP's proposed tariff changes resulted in an increase in the annual transmission revenue requirement of $10 million per year, with $6 million allocated to SPS' retail customers. The remaining $4 million would be paid by other wholesale loads in the SPS rate zone. On March 16, 2020, GridLiance also filed additional rate increases for 2020 which would raise their annual revenue requirement to $14 million, with approximately $9 million allocated to SPS' retail customers.

In August 2020, FERC issued an order on a question certified by the hearing judge for the FERC's review, in which FERC made certain findings in SPS' favor regarding the legal standard that applies to the ongoing hearing proceeding. In November 2020, FERC denied GridLiance's request for rehearing of the August 2020 order. In December 2020, GridLiance filed a petition for review at the D.C. Circuit of the August 2020 and November 2020 orders on the certified question.

The hearing portion of this proceeding was concluded in September 2020. The initial post-hearing brief was filed in October 2020. On June 3, 2021, the Administrative Law Judge issued a recommended decision, subject to FERC approval, that supports that the GridLiance facilities are transmission facilities and eligible for rate recovery under the SPP OATT. SPS filed a brief on exceptions to this decision, asking FERC to discard the judge's recommendation and deny the proposed GridLiance rate recovery. The matter is now pending with FERC, which will rule on the judge's decision and either sustain it, overturn it, or order further proceedings. SPS has incurred approximately $20 million in associated charges as of Sept. 30, 2021.

Contract Termination — SPS and LP&L have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the ERCOT (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million (lump sum or annual installments), to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The settlement agreement is subject to approval by the PUCT and FERC.

FERC NOPR on ROE Incentive Adders — In April 2021, the FERC issued a NOPR proposing to limit collection of ROE incentive adders for RTO membership to the first three years after an entity begins participation in an RTO. If adopted as a final rule, SPS would prospectively discontinue charging its current 50 basis point ROE incentive adders. Amounts related to a discontinuance of the adder would ultimately be offset by an increase in retail rates, subject to future rate cases.

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites — SPS is remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

	Three Months Ended Sept. 30	
(Millions of Dollars)	**2021**	**2020**
Operating leases		
PPA capacity payments	$ 13	$ 13
Other operating leases [(a)]	—	1
Total operating lease expense [(b)]	$ 13	$ 14

(a) Includes immaterial short-term lease expense for 2021 and 2020.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2021**	**2020**
Operating leases		
PPA capacity payments	$ 40	$ 35
Other operating leases [(a)]	2	3
Total operating lease expense [(b)]	$ 42	$ 38

(a) Includes short-term lease expense of $1 million for 2021 and 2020, respectively.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating leases as of Sept. 30, 2021:

(Millions of Dollars)	**PPA Operating Leases**	**Other Operating Leases**	**Total Operating Leases**
Total minimum obligation	$ 555	$ 56	$ 611
Interest component of obligation	(125)	(16)	(141)
Present value of minimum obligation	$ 430	$ 40	470
Less current portion			(29)
Noncurrent operating and finance lease liabilities			$ 441

VIEs

Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs at both Sept. 30, 2021 and Dec. 31, 2020 with entities that have been determined to be VIEs. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

Table of Contents

ITEM 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for SPS is omitted per conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in General Instruction H(2)(a) of Form 10-Q for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as, electric margin and ongoing earnings.

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that adjusts measures calculated and presented in accordance with GAAP.

SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, O&M expenses, DSM expenses, depreciation and amortization and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $260 million for the nine months ended Sept. 30, 2021 compared with approximately $242 million for the prior year, reflecting higher electric margin (capital investment recovery and regulatory outcomes), partially offset by decreased AFUDC.

Electric Margin

Electric revenues and fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses.

Electric revenues and margin:

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2021**	**2020**
Electric revenues [(a)]	$ 2,007	$ 1,434
Electric fuel and purchased power [(a)]	(1,195)	(627)
Electric margin	$ 812	$ 807

(a) The increase in revenue and electric fuel and purchased power is primarily due to Winter Storm Uri, resulting in higher fuel prices, as well as additional long-term energy sales/purchases market adjustments and SPP transactions.

Changes in electric margin:

(Millions of Dollars)	**Nine Months Ended Sept. 30, 2021 vs. 2020**
Regulatory rate outcomes (Texas and New Mexico)	$ 63
Sales and demand	20
Wholesale transmission revenue (net)	11
Texas 2019 rate case surcharge [(a)]	(70)
PTCs flowed back to customers (offset by lower ETR)	(34)
Other (net)	15
Total increase in electric margin	$ 5

(a) Impact to electric margin is due to the Texas rate case outcome, which was recognized in the third quarter of 2020 and was largely offset by recognition of previously deferred costs.

Non-Fuel Operating Expense and Other Items

AFUDC, Equity and Debt — AFUDC decreased $30 million year-to-date, primarily due to construction of the Sagamore wind farm.

Income Taxes — Income tax benefit increased $35 million for the first nine months of 2021. The increase was primarily driven by an increase in wind PTCs. Wind PTCs are largely credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

See Note 6 to the financial statements for further information.

Other

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, SPS incurred net natural gas, fuel and purchased energy costs of approximately $100 million (largely deferred as regulatory assets) in the first quarter.

Regulatory Overview — SPS has electric fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, February cost increases were deferred for future recovery with recovery proposed over a period of up to two years to significantly mitigate the impact to customer bills.

Proceedings initiated:

Jurisdiction	Regulatory Status
Texas	As part of the Texas fuel surcharge filing, SPS filed for recovery of $76 million, over 24 months, in under-collected purchased power and fuel costs through March 2021, subject to revision due to re-settlements. Of this amount, $62 million was attributed to Winter Storm Uri. In the third quarter, SPS filed a supplemental application and testimony to recover an additional $26 million in under-collected purchased power and fuel costs through June 2021 resulting primarily from SPP resettlements and continued increases in natural gas prices. The proposed recovery remains over 24 months beginning in February 2022. In October 2021, intervenors proposed a $10 million disallowance of Winter Storm Uri off-system sales margin in addition to recommending an extended recovery period. A public hearing is scheduled to begin on Nov. 1, 2021, with a final PUCT decision expected in early 2022.
New Mexico	The NMPRC approved SPS' request to recover $26 million of fuel costs over 24 months with no financing charge, subject to NMPRC review.

Supply Chain and Capital Expenditures

SPS' ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Overall, as a result of COVID-19, manufacturing processes have experienced disruptions related to scarcity of raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, storms and labor shortages. SPS continues to monitor the availability of materials and seek alternative suppliers as necessary.

Public Utility Regulation

The FERC and state and local regulatory commissions regulate SPS. SPS is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in utility rates through commission filings. Changes in operating costs can affect SPS' financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2020 and in Item 2 of SPS' Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2021 and Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2021, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2021 New Mexico Electric Rate Case	$62	June 2021	Pending
2021 Texas Electric Rate Case	$140	February 2021	Pending

Additional Information:

2021 New Mexico Electric Rate Case — In January 2021, SPS filed an electric rate case with the NMPRC with a current requested base rate increase of approximately $84 million.

The request was based on a historic test year ended Sept. 30, 2020, including expected capital additions through Feb. 28, 2021, a ROE of 10.35%, an equity ratio of 54.72% and a retail rate base of approximately $1.9 billion.

In June 2021, SPS and various parties filed an uncontested comprehensive stipulation, which includes:

- Base rate revenue increase of $62 million.
- ROE of 9.35% for purposes of filings related to (1) the Hale and Sagamore wind projects; and (2) reconciliation of the settlement revenue requirement.
- Equity ratio of 54.72%.
- Increase in depreciation expense of $6 million. This includes a change in the depreciable lives of the Tolk power plant to 2032 and coal handling assets at the Harrington facility to 2024.

The stipulation is subject to NMPRC approval. A NMPRC decision and implementation of final rates is anticipated in the fourth quarter of 2021.

2021 Texas Electric Rate Case — In February 2021, SPS filed an electric rate case with the PUCT and its municipalities. The current request is seeking an increase in base rates of approximately $140 million. SPS' net rate increase to Texas customers is expected to be approximately $71 million, or 9.2%, as a result of the offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is based on a ROE of 10.35%, an equity ratio of 54.60%, a rate base of approximately $3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020.

The request includes the effect of losing approximately 400 MW from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk power plant (from 2037 to 2032) and coal handling assets at the Harrington facility (to 2024).

In October 2021, the scheduled hearings were abated to continue progress on a potential rate case settlement between SPS and various intervenors.

Once final rates are approved, a surcharge will be requested from March 15, 2021 through the effective date of new base rates. A PUCT decision is expected in the first quarter of 2022.

Environmental

Affordable Clean Energy

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for greenhouse gas reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision would allow the EPA to proceed with alternate regulation of coal-fired power plants. If the new rules require additional investment, SPS believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

Table of Contents

Emerging Regulation

New regulations and legislation are being considered to regulate PFAS in drinking water, water discharges, commercial products, wastes, and other areas. PFAS are man-made chemicals found in many consumer products that can persist and accumulate in the environment. These chemicals have received heightened attention by environmental regulators. Increased regulation of PFAS and other emerging contaminants at the federal, state, and local level could have a potential adverse effect on our operations but at this time, it is uncertain what impact, if any, there will be on our operations, financial condition or cash flows. SPS will continue to monitor these regulatory developments and their potential impact on its operations.

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of Sept. 30, 2021, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2020, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation, dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	3.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Southwestern Public Service Company

October 28, 2021 By: /s/ JEFFREY S. SAVAGE

Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ BRIAN J. VAN ABEL

Brian J. Van Abel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

2021 Form 10-K

For the Fiscal Period Ended

December 31, 2021

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2021 or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

001-03789

(Commission File Number)

Southwestern Public Service Company

(Exact name of registrant as specified in its charter)

New Mexico	**75-0575400**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
790 South Buchanan Street, Amarillo, Texas	**79101**
(Address of Principal Executive Offices)	(Zip Code)

(303) 571-7511

(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act.
☐ Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of Feb. 23, 2022, 100 shares of common stock, par value $1.00 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Item 14 of Form 10-K is set forth under the heading "Independent Registered Public Accounting Firm – Audit and Non-Audit Fees" in Xcel Energy Inc.'s definitive Proxy Statement for the 2022 Annual Meeting of Shareholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 5, 2022. Such information set forth under such heading is incorporated herein by this reference hereto.

Southwestern Public Service Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I(2).

TABLE OF CONTENTS

This Form 10-K is filed by SPS. SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

Table of Contents

PART I

ITEM I — BUSINESS

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Other

AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
CWA	Clean Water Act
CWIP	Construction work in progress
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DSM	Demand side management
ELG	Effluent limitations guidelines
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
IPP	Independent power producing entity
ISO	Independent System Operators
LP&L	Lubbock Power and Light
MGP	Manufactured gas plant
Moody's	Moody's Investor Services
NAAQS	National Ambient Air Quality Standard
Native load	Customer demand of retail and wholesale customers whereby a utility has an obligation to serve under statute or long-term contract
NAV	Net asset value
NOL	Net operating loss
NOPR	Notice of proposed rulemaking
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
PFAS	Per- and PolyFluoroAlkyl Substances
PPA	Purchased power agreement
PTC	Production tax credit
REC	Renewable energy credit
ROE	Return on equity
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
VIE	Variable interest entity

Measurements

KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

Forward-Looking Statements

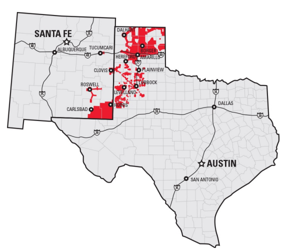
Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words “anticipate,” “believe,” “could,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should,” “will,” “would” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 (including risk factors listed from time to time by SPS in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including workforce impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints, and their impact on capital expenditures and/or the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers’ and counterparties’ ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties; and regulatory changes and/or limitations to the use of natural gas as an energy source.

Where to Find More Information

SPS is a wholly owned subsidiary of Xcel Energy Inc., and Xcel Energy’s website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov. The information on Xcel Energy’s website is not a part of, or incorporated by reference in, this annual report on Form 10-K.

Company Overview

Electric customers	0.4 million
Total assets	$9.3 billion
Rate Base (estimated)	$6.4 billion
ROE (net income / average stockholder's equity)	9.22%
Electric generating capacity	5,249 MW
Electric transmission lines (conductor miles)	40,754 miles
Electric distribution lines (conductor miles)	22,651 miles



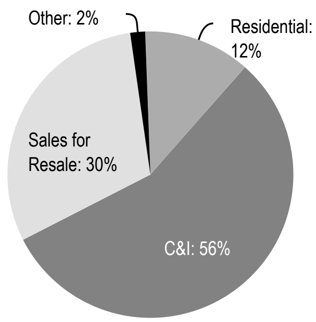
SPS was incorporated in 1921 under the laws of New Mexico. SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.

Table of Contents

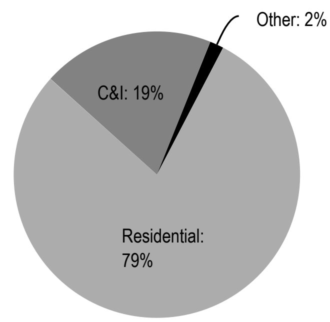
Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities. SPS had electric sales volume of 29,900 (millions of KWh), 0.4 million customers and electric revenues of $2,465 (millions of dollars) for 2021.

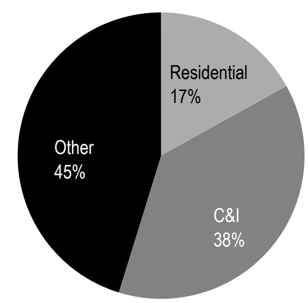
Sales Volume



Number of Customers



Revenues

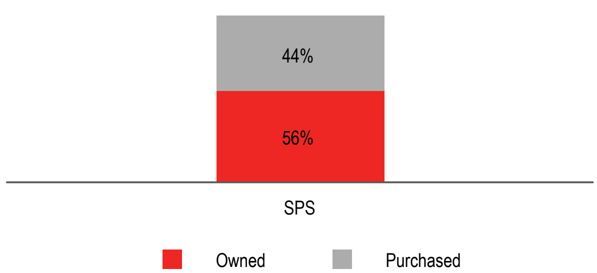


Retail Sales/Revenue Statistics [(a)]

	2021	2020
KWH sales per retail customer	51,872	51,694
Revenue per retail customer	$ 3,469	$ 2,925
Residential revenue per KWh	11.56 ¢	9.77 ¢
Large C&I revenue per KWh	4.53 ¢	3.65 ¢
Small C&I revenue per KWh	8.08 ¢	6.99 ¢
Total retail revenue per KWh	6.69 ¢	5.66 ¢

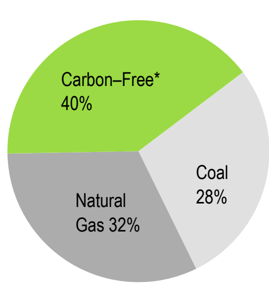
(a) See Note 6 to the financial statements for further information.

Owned and Purchased Energy Generation — 2021



Electric Energy Sources

Total electric energy generation by source (including energy market purchases) for the year ended Dec. 31, 2021:



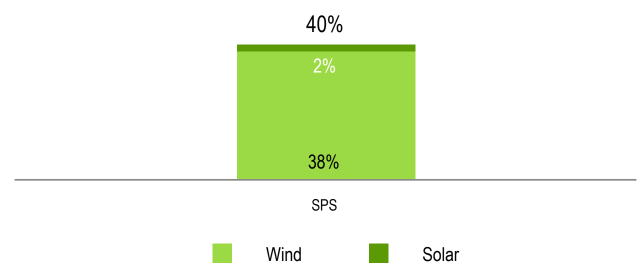
*Distributed generation from the Solar*Rewards® program is not included (approximately 5 million KWh for 2021).

Carbon–Free

SPS' carbon–free energy portfolio includes wind and solar power from both owned generating facilities and PPAs. Carbon–free percentages will vary year over year based on system additions, commodity costs, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Carbon–free energy as a percentage of total energy for 2021:



Wind

Owned — Owned and operated wind farms with corresponding capacity:

2021		2020	
Wind Farms	Capacity [(a)]	Wind Farms	Capacity [(b)]
2	984 MW	2	967 MW

(a) Summer 2021 net dependable capacity.
(b) Summer 2020 net dependable capacity.

PPAs — Number of PPAs with capacity range:

2021		2020	
PPAs	Range	PPAs	Range
17	1 MW — 250 MW	18	1 MW — 250 MW

Capacity — Wind capacity:

2021	2020
2,548 MW	2,535 MW

Average Cost (Owned) — Average cost per MWh of wind energy from owned generation:

2021		2020	
$	17	$	17

Average Cost (PPAs) — Average cost per MWh of wind energy under existing PPAs:

2021		2020	
$	27	$	26

Solar

Solar energy PPAs:

Type	Capacity (MW)
Distributed Generation	15
Utility-Scale	192
Total	207

Average Cost (PPAs) — Average cost per MWh of solar energy under existing PPAs:

2021		2020	
$	61	$	59

Fossil Fuel

SPS' fossil fuel energy portfolio includes coal and natural gas power from both owned generating facilities and PPAs.

See Item 2 — Properties for further information.

Coal

SPS owns and operates coal units with approximately 2,100 MW of total 2021 net summer dependable capacity.

Approved early coal plant retirements:

Year	Plant Unit	Capacity
2024	Harrington [(a)]	1,018 MW

(a) Reflects expected conversion from coal to natural gas following the TCEQ order that Harrington cease use of coal fuel by Jan. 1, 2025, pending PUCT and NMPRC review.

Proposed		
Year	Plant Unit	Capacity (MW)
2034	Tolk 1	532
2034	Tolk 2	535

Coal Fuel Cost

Delivered cost per MMBtu of coal consumed for owned electric generation and the percentage of total fuel requirements:

	Coal		
	Cost		Percent
2021	$	2.07	66 %
2020		2.28	40

Natural Gas

SPS has eight natural gas plants with approximately 2,200 MW of total 2021 net summer dependable capacity.

Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Natural Gas Cost

Delivered cost per MMBtu of natural gas consumed for owned electric generation and the percentage of total fuel requirements:

	Natural Gas		
	Cost		Percent
2021 [(a)]	$	6.72	34 %
2020		1.43	60

(a) Reflective of Winter Storm Uri.

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

System Peak Demand (MW)			
2021		2020	
4,054	Aug. 9	4,195	July 14

Transmission

Transmission lines deliver electricity over long distances from power sources to transmission substations closer to customers. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy. SPS owns more than 40,000 conductor miles of transmission lines across its service territory.

Transmission projects completed in 2021 include:

Project	Miles	Size
Roadrunner-China Draw	41	345 KV

Notable upcoming projects:

Project	Miles	Size (KV)	Completion Date
Tolk Plant Substation			
Bus Reconfiguration	n/a	345, 230	2022
Twist to Wilco Line	4	115	2024

See Item 2 - Properties for further information.

Distribution

Distribution lines allow electricity to travel at lower voltages from substations directly to customers. SPS has a vast distribution network, owning and operating approximately 23,000 conductor miles of distribution lines across our service territory. To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure.

See Item 2 - Properties for further information.

Table of Contents

Governmental Regulations

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid and hazardous wastes or substances. Certain SPS activities require registrations, permits, licenses, inspections and approvals from these agencies. SPS has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities strive to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine what additional facilities or modifications of existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have.

SPS must comply with emission levels that may require the purchase of emission allowances.

There are significant environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. SPS has undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Future environmental regulations may result in substantial costs.

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for GHG reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision would allow the EPA to proceed with alternate regulation of coal-fired power plants. However, the Court of Appeals decision is now before the U.S. Supreme Court, where the Court is expected to rule on the nature and extent of the EPA's GHG regulatory authority. If any new rules require additional investment, SPS believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

In October 2020, the TCEQ approved an agreement that SPS will convert the Harrington plant from coal to natural gas by Jan. 1, 2025. This conversion is necessary to attain Federal Clean Air Act standards for emissions of SO_2.

SPS seeks to address climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner.

Emerging Environmental Regulation

New regulations and legislation are being considered to regulate PFAS in drinking water, water discharges, commercial products, wastes, and other areas. PFAS are man-made chemicals found in many consumer products that can persist and accumulate in the environment. These chemicals have received heightened attention from environmental regulators. Increased regulation of PFAS and other emerging contaminants at the federal, state, and local level could have a potential adverse effect on our operations but at this time, it is uncertain what impact, if any, there will be on our operations, financial condition or cash flows. SPS will continue to monitor these regulatory developments and their potential impact on its operations.

Other

Our operations are subject to workplace safety standards under the Federal Occupational Safety and Health Act of 1970 ("OSHA") and comparable state laws that regulate the protection of worker health and safety. In addition, the Company is subject to other government regulations impacting such matters as labor, competition, data privacy, etc. Based on information to date and because our policies and business practices are designed to comply with all applicable laws, we do not believe the effects of compliance on our operations, financial condition or cash flows are material.

General

Seasonality

Demand for electric power is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, SPS' operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

Competition

SPS is subject to public policies that promote competition and development of energy markets. SPS' industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them.

Several states have incentives for the development of rooftop solar, community solar gardens and other distributed energy resources. Distributed generating resources are potential competitors to SPS' electric service business with these incentives and federal tax subsidies.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. SPS' wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission system of SPS on a comparable basis to serve their native load.

FERC Order No. 1000 established competition for ownership of certain new electric transmission facilities under Federal regulations. Some states have state laws that allow the incumbent a Right of First Refusal to own these transmission facilities.

FERC Order 2222 requires that RTO and ISO markets allow participation of aggregations of distributed energy resources. This order is expected to incentivize distributed energy resource adoption, however implementation is expected to vary by RTO/ISO and the near, medium, and long-term impacts of Order 2222 remain unclear.

SPS has franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power, such as municipalization. No municipalization activities are occurring presently.

While facing these challenges, SPS believes its rates and services are competitive with alternatives currently available.

Employees

As of Dec. 31, 2021, SPS had 1,099 full-time employees and one part-time employee, of which 736 were covered under collective-bargaining agreements.

ITEM 1A — RISK FACTORS

Xcel Energy, which includes SPS, is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. These risks should be carefully considered together with the other information set forth in this report and future reports that we file with the SEC. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Oversight of Risk and Related Processes

SPS' Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of key risks.

At a threshold level, SPS maintains a robust compliance program through promoting a culture of compliance beginning with the tone at the top. The risk mitigation process includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management. SPS further mitigates inherent risks through formal risk committees and corporate functions such as internal audit, and internal controls over financial reporting and legal.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and risk analysis occurs formally through risk assessment conducted by senior management, the financial disclosure process, hazard risk procedures, internal audit and compliance with financial and operational controls.

Management also identifies and analyzes risk through the business planning process, development of goals and establishment of key performance indicators, including identification of barriers to implementing our strategy. The business planning process also identifies likelihood and mitigating factors to prevent the assumption of inappropriate risk to meet goals.

Management communicates regularly with the Board of Directors and its sole stockholder regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors, providing information on the risks that management believes are material, including financial impact, timing, likelihood and mitigating factors. The Board of Directors regularly reviews management's key risk assessments, which includes areas of existing and future macroeconomic, financial, operational, policy, environmental and security risks.

The overall oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors' governance of SPS. Processes are in place to ensure appropriate risk oversight, as well as identification and consideration of new risks.

Operational Risks

Our electric generation, transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages. These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses. Our natural gas transmission activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. We maintain insurance against most, but not all, of these risks and losses to employees, third-party contractors, customers or the public. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows as well as potential loss of reputation.

Other uncertainties and risks inherent in operating and maintaining SPS' facilities include, but are not limited to:

- Risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned.
- Failures in the availability, acquisition or transportation of fuel or other necessary supplies.
- The impact of unusual or adverse weather conditions and natural disasters, including, but not limited to, tornadoes, icing events, floods and droughts.
- Performance below expected or contracted levels of output or efficiency (e.g., performance guarantees).
- Availability of replacement equipment.
- Availability of adequate water resources and ability to satisfy water intake and discharge requirements.
- Inability to identify, manage properly or mitigate equipment defects.
- Use of new or unproven technology.
- Risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation and lack of available alternative fuel sources.
- Increased competition due to, among other factors, new facilities, excess supply, shifting demand and regulatory changes.

Additionally, compliance with existing and potential new regulations related to the operation and maintenance of our natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the Department of Transportation's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with these regulations and systematically monitor and renew infrastructure over time, however, a significant incident or material finding of non-compliance could result in penalties and higher costs of operations.

Our electric transmission and distribution operations and natural gas transmission operations are dependent upon complex information technology systems and network infrastructure, the failure of which could disrupt our normal business operations, which could have a material adverse effect on our ability to process transactions and provide services.

Our utility operations are subject to long-term planning and project risks.

Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of in-service dates and typically subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. Our long-term resource plan is dependent on our ability to obtain required approvals, develop necessary technical expertise, allocate and coordinate sufficient resources and adhere to budgets and timelines.

In addition, the long-term nature of both our planning and our asset lives are subject to risk. The electric utility sector is undergoing significant change (e.g., increases in energy efficiency, wider adoption of distributed generation and shifts away from fossil fuel generation to renewable generation).

Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, and potentially stranded costs if we are not able to fully recover costs and investments.

The magnitude and timing of resource additions and changes in customer demand may not coincide with evolving customer preference for generation resources and end-uses, which introduces further uncertainty into long-term planning. Efforts to electrify the transportation and building sectors to reduce GHG emissions may result in higher electric demand and lower natural gas demand over time. Higher electric demand may require us to adopt new technologies and make significant transmission and distribution investments including advanced grid infrastructure, which increases exposure to overall grid instability and technology obsolescence. Evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may impact our resource mix and put pressure on our ability to recover capital investments in natural gas generation and delivery. Multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We are subject to longer-term availability of inputs such as coal, natural gas and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

Our utilities are highly dependent on suppliers to deliver components in accordance with short and long-term project schedules.

Our products contain components that are globally sourced from suppliers who, in turn, source components from their suppliers. A shortage of key components in which an alternative supplier is not identified could significantly impact project plans. Such impacts could include timing of projects, including potential for project cancellation. Failure to adhere to project budgets and timelines could adversely impact our results of operations, financial condition or cash flows.

We are subject to commodity risks and other risks associated with energy markets and energy production.

In the event fuel costs increase, customer demand could decline and bad debt expense may rise, which may have a material impact on our results of operations. Despite existing fuel recovery mechanisms, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows and liquidity.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs and supply shortages may not be fully resolved, which could cause disruptions in our ability to provide services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process. Also, significantly higher energy or fuel costs relative to sales commitments could negatively impact our cash flows and results of operations.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk.

Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability. The management of risks associated with hedging and trading is based, in part, on programs and procedures which utilize historical prices and trends.

Due to the inherent uncertainty involved in price movements and potential deviation from historical pricing, SPS is unable to fully assure that its risk management programs and procedures would be effective to protect against all significant adverse market deviations. In addition, SPS cannot fully assure that its controls will be effective against all potential risks, including, without limitation, employee misconduct. If such programs and procedures are not effective, SPS' results of operations, financial condition or cash flows could be materially impacted.

Failure to attract and retain a qualified workforce could have an adverse effect on operations.

In 2021, the competition for talent has become increasingly intense as a result of the ongoing "great resignation", and we may experience increased employee turnover due to this tightening labor market. In addition, specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets, which may pose additional difficulty for us as we work to recruit, retain and motivate employees in this climate. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

Our operations use third-party contractors in addition to employees to perform periodic and ongoing work.

We rely on third-party contractors to perform operations, maintenance and construction work. Our contractual arrangements with these contractors typically include performance standards, progress payments, insurance requirements and security for performance. Poor vendor performance or contractor unavailability could impact ongoing operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

Our employees, directors, third-party contractors, or suppliers may violate or be perceived to violate our Codes of Conduct, which could have an adverse effect on our reputation.

We are exposed to risk of employee or third-party contractor fraud or other misconduct. All employees and members of the Board of Directors are subject to comply with our Code of Conduct and are required to participate in annual training. Additionally, suppliers are subject to comply with our supplier Code of Conduct. SPS does not tolerate discrimination, violations of our Code of Conduct or other unacceptable behaviors. However, it is not always possible to identify and deter misconduct by employees and other third-parties, which may result in governmental investigations, other actions or lawsuits. If such actions are taken against us we may suffer loss of reputation and such actions could have a material effect on our financial condition, results of operations and cash flows.

We are a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. can exercise substantial control over our dividend policy and business and operations and may exercise that control in a manner that may be perceived to be adverse to our interests.

All of the members of our Board of Directors, as well as many of our executive officers, are officers of Xcel Energy Inc. Our Board or Directors makes determinations with respect to a number of significant corporate events, including the payment of our dividends.

We have historically paid quarterly dividends to Xcel Energy Inc. In 2021, 2020 and 2019 we paid $310 million, $313 million and $333 million of dividends to Xcel Energy Inc., respectively. If Xcel Energy Inc.'s cash requirements increase, our Board of Directors could decide to increase the dividends we pay to Xcel Energy Inc. to help support Xcel Energy Inc.'s cash needs. This could adversely affect our liquidity. The most restrictive dividend limitation for SPS is imposed by its state regulatory commissions. State regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy Inc., by requiring a minimum equity-to-total capitalization ratio.

See Note 5 to the financial statements for further information.

Financial Risks

Our profitability depends on our ability to recover costs from our customers and changes in regulation may impair our ability to recover costs from our customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

The profitability of our operations is dependent on our ability to recover the costs of providing energy and utility services and earn a return on our capital investment. Our rates are generally regulated and based on an analysis of our costs incurred in a test year. We are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital.

There can also be no assurance that our regulatory commissions will judge all our costs to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery. Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair our ability to recover costs historically collected from customers, or we could exceed caps on capital costs required by commissions and result in less than full recovery.

Changes in the long-term cost-effectiveness or to the operating conditions of our assets may result in early retirements of utility facilities. While regulation typically provides cost recovery relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

Higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that our current credit ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs use of historic test years, elimination or riders or interim rates, increasing depreciation lives, lower returns on equity, changes to equity ratios and impacts of tax policy may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any credit ratings downgrade could lead to higher borrowing costs or lower proceeds from equity issuances. It could also impact our ability to access capital markets. Also, we may enter into contracts that require posting of collateral or settlement if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates or lower proceeds from equity issuances. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the economy and unemployment rates. Credit risk also includes the risk that counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

We may have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, (e.g., SPP, PJM Interconnection, LLC, Midcontinent Independent System Operator, Inc. and the Electric Reliability Council of Texas), in which any credit losses are socialized to all market participants.

We have additional indirect credit exposure to financial institutions from letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

As we are a subsidiary of Xcel Energy Inc. we may be negatively affected by events impacting the credit or liquidity of Xcel Energy Inc. and its affiliates.

If either S&P or Moody's were to downgrade Xcel Energy Inc.'s debt securities below investment grade, it would increase Xcel Energy Inc.'s cost of capital and restrict its access to the capital markets. This could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

As of Dec. 31, 2021, Xcel Energy Inc. and its utility subsidiaries had approximately $21.8 billion of long-term debt and $1.6 billion of short-term debt and current maturities. Xcel Energy Inc. provides various guarantees and bond indemnities supporting some of its subsidiaries by guaranteeing the payment or performance by these subsidiaries for specified agreements or transactions.

Xcel Energy also has other contingent liabilities resulting from various tax disputes and other matters. Xcel Energy Inc.'s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of Xcel Energy Inc.'s guarantees limit its exposure to a maximum amount that is stated in the guarantees.

As of Dec. 31, 2021, Xcel Energy had guarantees outstanding with a $1 million maximum stated amount and immaterial exposure. Xcel Energy also had additional guarantees of $59 million at Dec. 31, 2021 for performance and payment of surety bonds for the benefit of itself and its subsidiaries, with total exposure that cannot be estimated at this time. If Xcel Energy Inc. were to become obligated to make payments under these guarantees and bond indemnities or become obligated to fund other contingent liabilities, it could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements of these plans. Estimates and assumptions may change. In addition, the Pension Protection Act sets the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high numbers of retirements or employees leaving would trigger settlement accounting and could require SPS to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs.

Increasing costs associated with health care plans may adversely affect our results of operations.

Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Health care legislation could also significantly impact our benefit programs and costs.

Federal tax law may significantly impact our business.

SPS collects estimated federal, state and local tax payments through regulated rates. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. If tax rates are increased, there could be timing delays before regulated rates provide for recovery of such tax increases in revenues. In addition, certain IRS tax policies such as tax normalization may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills which could lead to additional bad debt expense.

Additionally, SPS faces competitive factors, which could have an adverse impact on our financial condition, results of operations and cash flows. Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may inhibit our ability to acquire sufficient supplies.

We operate in a capital intensive industry and federal trade policy could significantly impact the cost of materials we use. There may be delays before these additional material costs can be recovered in rates.

We face risks related to health epidemics and other outbreaks, which may have a material effect on our financial condition, results of operations and cash flows.

The global outbreak of COVID-19 continues to impact countries, communities, supply chains and markets. A high degree of uncertainty continues to exist regarding the pandemic; the duration and magnitude of business restrictions (domestically and globally); the potential shortages of employees and third-party contractors due to quarantine policies, vaccination requirements or government restrictions; re-shutdowns, if any, and the level and pace of economic recovery.

Although the financial impact of the pandemic on our financial results has largely been mitigated, we cannot ultimately predict whether it will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact of the virus on the health of our employees, our supply chain or our ability to recover higher costs associated with managing through the pandemic. The impact of COVID-19 may exacerbate other risks discussed herein, which could have a material effect on us. The situation is evolving and additional impacts may arise.

Operations could be impacted by war, terrorism or other events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows.

The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility.

We also face the risks of possible loss of business due to significant events such as severe storms, severe temperature extremes, wildfires, widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a workforce disruption.

In addition, major catastrophic events throughout the world may disrupt our business. Xcel Energy participates in a global supply chain, which includes materials and components that are globally sourced. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to reliably serve our customers.

A major disruption could result in a significant decrease in revenues and additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows. SPS participates in GridEx, which is the largest grid security exercise in North America. These efforts, led by the NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

A cyber incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. Our industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. During the normal course of business, we have experienced and expect to continue to experience attempts to compromise our information technology and control systems, network infrastructure and other assets. To date, no cybersecurity incident or attack has had a material impact on our business or results of operation.

Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers' operations, could also negatively impact our business.

Our supply chain for procurement of digital equipment and services may expose software or hardware to these risks and could result in a breach or significant costs of remediation. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. Cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including asset failure or unauthorized access to assets or information. A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric utility business is seasonal and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change may create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. International agreements could additionally lead to future federal or state regulations.

In 2015, the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2º Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5º Celsius. In April 2021, ahead of the United Nations Climate Change Conference in Glasgow, the Biden Administration committed the U.S. to a Nationally Determined Contribution of 50-52% net GHG emissions reduction economy-wide from 2005 levels. This commitment and other agreements made in Glasgow could result in future additional GHG reductions in the United States. In addition, the Biden Administration has announced plans to implement new climate change programs, including potential regulation of GHG emissions targeting the utility industry.

Many states and localities continue to pursue their own climate policies. The steps SPS has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation or retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties. In the event of serious incidents, these agencies may pursue penalties. In addition, certain states have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

The continued use of natural gas for power generation has increasingly become a public policy advocacy target. These efforts may result in a limitation of natural gas as an energy source for power generation, which could impact our ability to reliably and affordably serve our customers.

In recent years, there have been various local and state agency proposals within and outside our service territories that would attempt to restrict the use and availability of natural gas. If such policies were to prevail, we may be forced to make new resource investment decisions which could potentially result in stranded costs if we are not able to fully recover costs and investments and impact the overall reliability of our service.

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate sites where our past activities, or the activities of other parties, caused environmental contamination.

Changes in environmental policies and regulations or regulatory decisions may result in early retirements of our generation facilities. While regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or O&M costs incurred to comply with the requirements.

In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events.

Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

Climate change may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers, which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We have committed to a number of long-term climate change goals, which in part are dependent on future technologies not currently in existence. Given the long-term nature of these goals, there is an inherent uncertainty due to internal and external factors regarding our ability to achieve our stated climate change goals. To the extent climate change goals are not met, this could negatively impact our reputation and potentially result in financial risk.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities. While we carry liability insurance, given an extreme event, if SPS was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of power plants and increase the cost for energy. Adverse events may result in increased insurance costs and/or decreased insurance availability. We may not recover all costs related to mitigating these physical and financial risks.

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 2 — PROPERTIES

Virtually all of the utility plant property of SPS is subject to the lien of its first mortgage bond indenture.

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	225
Harrington-Amarillo, TX, 3 Units [(b)]	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	298
Tolk-Muleshoe, TX, 2 Units [(d)]	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	207
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units	Wind	2019	477 [(c)]
Sagamore-Dora, NM, 240 Units	Wind	2020	507 [(c)]
		Total	5,249

(a) Summer 2021 net dependable capacity.

(b) Harrington is expected to be converted to natural gas by the end of 2024.

(c) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

(d) Tolk Unit 1 and 2 are proposed to be retired in 2034.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2021:

Conductor Miles	
Transmission	
500 KV	—
345 KV	11,688
230 KV	9,763
161 KV	—
138 KV	—
115 KV	14,880
Less than 115 KV	4,423
Total Transmission	40,754
Distribution	
Less than 115 KV	22,651
Total	**63,405**

SPS had 458 electric utility transmission and distribution substations at Dec. 31, 2021.

Natural gas utility mains at Dec. 31, 2021:

Miles	
Transmission	20

ITEM 3 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

See Note 10 to the financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5 — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

SPS is a wholly owned subsidiary of Xcel Energy Inc. and there is no market for its common equity securities.

See Note 5 to the financial statements for further information.

The dividends declared during 2021 and 2020 were as follows:

(Millions of Dollars)	2021	2020
First quarter	$ 52	$ 76
Second quarter	79	55
Third quarter	123	136
Fourth quarter	60	54

ITEM 6 — [RESERVED]

ITEM 7 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for SPS is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries. It is replaced with management's narrative analysis and the results of operations for the current year as set forth in general instructions I(2)(a) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing earnings. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. We use these non-GAAP financial measures to evaluate and provide details of SPS' core earnings and underlying performance.

We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of SPS. For the years ended Dec. 31, 2021 and 2020, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

2021 Comparison with 2020

SPS' net income was $318 million for 2021, compared with net income of $295 million for 2020. The increase was primarily due to capital investment recovery, other regulatory outcomes and higher sales and demand, partially offset by decreased AFUDC.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas and coal. However, these price fluctuations generally have minimal impact on earnings impact due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes.

Electric Revenues, Fuel and Purchased Power and Electric Margin

(Millions of Dollars)	2021	2020
Electric revenues	$ 2,465	$ 1,870
Electric fuel and purchased power	(1,432)	(835)
Electric margin	$ 1,033	$ 1,035

Changes in Electric Margin

(Millions of Dollars)	2021 vs. 2020
Texas 2019 rate case surcharge [(a)]	$ (70)
PTCs flowed back to customers (offset by lower ETR)	(45)
Wholesale transmission revenue (net)	14
Sales and demand	23
Regulatory rate outcomes (Texas and New Mexico)	63
Other (net)	13
Total decrease in electric margin	$ (2)

(a) Impact is due to the Texas rate case outcome, which resulted in a revenue increase that was recognized in the third quarter of 2020 (largely offset by recognition of previously deferred costs).

Non-Fuel Operating Expense and Other Items

AFUDC, Equity and Debt — AFUDC decreased $41 million year-to-date, primarily due to the Sagamore wind farm being placed in service at the end of 2020.

Income Taxes — Income tax benefit increased $49 million for 2021. The increase was primarily driven by an increase in wind PTCs. Wind PTCs are generally credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

Other

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, SPS incurred net natural gas, fuel and purchased energy costs of approximately $100 million (largely deferred as regulatory assets).

Regulatory Overview — Xcel Energy has natural gas, fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, the utility subsidiaries have deferred February 2021 cost increases for future recovery and sought recovery of the cost increases over a period of up to 30 months to mitigate the impact to customer bills. Additionally, we did not request recovery of financing costs in order to further limit the impact to our customers.

Proceedings initiated:

Jurisdiction	Regulatory Status
Texas	As part of the Texas fuel surcharge filing, SPS filed for recovery of $76 million, over 24 months, in under-collected purchased power and fuel costs through March 2021, subject to revision due to re-settlements. Of this amount, $62 million was attributed to Winter Storm Uri. In the third quarter, SPS filed a supplemental application and testimony to recover an additional $26 million in under-collected purchased power and fuel costs through June 2021 resulting primarily from SPP resettlements and continued increases in natural gas prices. In November 2021, the Administrative Law Judge abated the hearing schedule to allow the parties to continue settlement negotiations. In December 2021, SPS filed its triennial Fuel Reconciliation, under which the PUCT will consider prudence of SPS' fuel costs for the period July 2018 - June 2021, including Winter Storm Uri. In January 2022, SPS and other parties filed a stipulation/motion for interim rates. The filing covers all fuel under-collections occurring between January 2020 and August 2021, totaling $121 million. The settlement does not address the prudence of Winter Storm Uri costs nor the retention of $11 million related to market sales during the event. These items will be reviewed through the triennial Fuel Reconciliation proceeding and are subject to a final PUCT decision. Interim rates, designed to collect up to $110 million over a period of 30 months, will begin on Feb. 1, 2022.
New Mexico	In March 2021, the NMPRC approved SPS' request to recover $26 million of fuel costs over 24 months with no financing charge, subject to NMPRC review.

Public Utility Regulation

The FERC and state and local regulatory commissions regulate SPS. SPS is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in utility rates through commission filings. Changes in operating costs can affect SPS' financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

See Rate Matters within Note 10 to the financial statements for further information.

Table of Contents

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PUCT	Retail electric operations, rates, services, construction of transmission or generation and other aspects of SPS' electric operations. The municipalities in which SPS operates in Texas have original jurisdiction over rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.
NMPRC	Retail electric operations, retail rates and services and the construction of transmission or generation.
FERC	Wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce.
SPP RTO and SPP Integrated and Wholesale Markets	SPS is a transmission owning member of the SPP RTO and operates within the SPP RTO and SPP integrated and wholesale markets. SPS is authorized to make wholesale electric sales at market-based prices.

Recovery Mechanisms

Mechanism	Additional Information
Distribution Cost Recovery Factor	Recovers distribution costs not included in rates in Texas.
Energy Efficiency Cost Recovery Factor	Recovers costs for energy efficiency programs in Texas.
Energy Efficiency Rider	Recovers costs for energy efficiency programs in New Mexico.
Fuel and Purchased Power Cost Adjustment Clause	Adjusts monthly to recover actual fuel and purchased power costs in New Mexico.
Power Cost Recovery Factor	Allows recovery of purchased power costs not included in Texas rates.
Renewable Portfolio Standards	Recovers deferred costs for renewable energy programs in New Mexico.
Transmission Cost Recovery Factor	Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in Texas base rates.
Fixed Fuel and Purchased Recovery Factor	Provides for the over- or under-recovery of energy expenses in Texas. Regulations require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.
Wholesale Fuel and Purchased Energy Cost Adjustment	SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Pending and Recently Concluded Regulatory Proceedings

2021 New Mexico Electric Rate Case — In January 2021, SPS filed an electric rate case with the NMPRC with a current requested base rate increase of approximately $84 million.

In June 2021, SPS and various parties filed an uncontested stipulation with the NMPRC, which reflected a $62 million rate increase, a change in the depreciation life of the Tolk coal plant to 2032, an equity ratio of 54.72% and ROE of 9.35% for reconciliation statements and determining the revenue requirements for the Sagamore and Hale wind projects. In December 2021, the Hearing Examiner issued a recommendation that the NMPRC approve the rate case settlement agreement without modification.

On Feb. 2, 2022, the NMPRC voted 3-2 to reject the uncontested stipulation as filed. The NMPRC then approved a modified settlement, which would maintain the proposed revenue requirement increase of $62 million, but would adjust the class cost allocation such that all rate classes would have a uniform increase of 4.89%. The NMPRC required the parties to either file their acceptance or opposition to the modified settlement.

On Feb. 9, 2022, the signatories informed the NMPRC they did not unanimously support the modifications. Accordingly, the Hearing Examiner will issue a procedural order for further proceedings on SPS' originally filed application.

On Feb. 10, 2022, SPS filed a motion requesting the NMPRC either approve the original settlement or approve the modified settlement.

On Feb. 16, 2022, the NMPRC voted to reconsider its order and voted 3-2 to approve the stipulation without modification. New rates will go into effect on Feb. 26, 2022.

2021 Texas Rate Case — In February 2021, SPS filed an electric rate case with the PUCT and its municipalities, seeking an increase in base rates of approximately $140 million. SPS' proposed net rate increase to Texas customers was approximately $71 million, or 9.2%, as a result of the offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is based on a ROE of 10.35%, an equity ratio of 54.60%, a rate base of approximately $3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020. The request includes the effect of losing approximately 400 MW from a wholesale transmission customer and changes to depreciation lives of SPS' Tolk power plant (from 2037 to 2032) and coal handling assets at the Harrington facility (to 2024).

On Jan. 26, 2022, SPS and intervenors filed a blackbox settlement. Key terms include:

- A base rate increase of approximately $89 million effective back to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for AFUDC purposes only.
- The depreciation lives for Tolk moved up to 2034 and Harrington coal assets moved up to 2024.

In February 2022, the ALJ issued an order approving interim rates to be effective on March 1, 2022. A PUCT decision is expected in the first quarter of 2022.

FERC NOPR on ROE Incentive Adders — In April 2021, the FERC issued a NOPR proposing to limit collection of ROE incentive adders for RTO membership to the first three years after an entity begins participation in an RTO. If adopted as a final rule, SPS would prospectively discontinue charging their current 50 basis point ROE incentive adders. Amounts related to a discontinuance of the adder would ultimately be offset by an increase in retail rates, subject to future rate cases.

Purchased Power Arrangements and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements.

Purchased Power — SPS purchases power from other utilities and IPPs. Long-term purchased power contracts typically require periodic capacity and energy charges. SPS also makes short-term purchases to meet system load and energy requirements to replace owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers.

Natural Gas

SPS does not provide retail natural gas service, but purchases and transports natural gas for its generation facilities and operates limited natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce and the PHMSA and PUCT for pipeline safety compliance.

Wholesale and Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and to hedge sales and purchases.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivatives, Risk Management and Market Risk

SPS is exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

See Note 8 to the financial statements for further information.

SPS is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While SPS expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose SPS to certain credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the pension fund, and SPS' ability to earn a return on short-term investments.

Commodity Price Risk — SPS is exposed to commodity price risk in its electric operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products. Commodity price risk is also managed through the use of financial derivative instruments.

SPS' risk management policy allows it to manage commodity price risk per commission approved hedge plans.

Wholesale and Commodity Trading Risk — SPS conducts wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS' risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

Interest Rate Risk — SPS is subject to interest rate risk. SPS' risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

A 100-basis-point change in the benchmark rate on SPS' variable rate debt would have a $2 million and $3 million impact on pretax interest expense annually in 2021 and 2020, respectively.

Credit Risk — SPS is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. SPS maintains credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2021, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $3 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $3 million. At Dec. 31, 2020, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $1 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $1 million.

SPS conducts credit reviews for all counterparties and employs credit risk controls, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase SPS' credit risk.

Fair Value Measurements

SPS uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value. SPS' investments held in rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

Commodity Derivatives — SPS monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. Given the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2021.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2021.

See Note 8 to the financial statements for further information.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See Item 15-1 for an index of financial statements included herein.

See Note 12 to the financial statements for further information.

Management Report on Internal Control Over Financial Reporting

The management of SPS is responsible for establishing and maintaining adequate internal control over financial reporting. SPS' internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s and SPS' management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

SPS management assessed the effectiveness of SPS' internal control over financial reporting as of Dec. 31, 2021. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework (2013).* Based on our assessment, we believe that, as of Dec. 31, 2021, SPS' internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ ROBERT C. FRENZEL	/s/ BRIAN J. VAN ABEL
Robert C. Frenzel	Brian J. Van Abel
Chairman, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer and Director
Feb. 23, 2022	Feb. 23, 2022

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Southwestern Public Service Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Southwestern Public Service Company (the "Company") as of December 31, 2021 and 2020, the related statements of income, comprehensive income, common stockholder's equity and cash flows for each of the three years in the period ended December 31, 2021, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Assets and Liabilities - Impact of Rate Regulation on the Financial Statements — Refer to Notes 4 and 10 to the financial statements.

Critical Audit Matter Description

The Company is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric transmission and distribution companies in New Mexico and Texas. The Company is also subject to the jurisdiction of the Federal Energy Regulatory Commission for its wholesale electric operations, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with North American Electric Reliability Corporation standards, asset transactions and mergers and natural gas transactions in interstate commerce, (collectively with state utility regulatory agencies, the "Commissions"). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant and equipment, regulatory assets and liabilities, operating revenues and expenses, and income taxes.

The Company is subject to regulatory rate setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in assets required to deliver services to customers. Accounting for the Company's regulated operations provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. The Commissions' regulation of rates is premised on the full recovery of incurred costs and a reasonable rate of return on invested capital. Decisions by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. In the rate setting process, the Company's rates result in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant, and 3) a refund due to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the recognition of regulatory assets or liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company, regulatory statutes, interpretations, procedural schedules and memorandums, filings made by intervenors, experts' testimony and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances. We also evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects. If the full recovery of project costs is being challenged by intervenors, we evaluated management's assessment of the probability of a disallowance. We evaluated the external information and compared to the Company's recorded regulatory assets and liabilities for completeness.
- We obtained management's analysis and correspondence from counsel, as appropriate, regarding regulatory assets or liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 23, 2022

We have served as the Company's auditor since 2002.

Table of Contents

SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2021	2020	2019
Operating revenues	$ 2,465	$ 1,870	$ 1,826
Operating expenses			
Electric fuel and purchased power	1,432	835	875
Operating and maintenance expenses	271	275	285
Demand side management expenses	17	16	17
Depreciation and amortization	300	295	230
Taxes (other than income taxes)	79	90	72
Total operating expenses	2,099	1,511	1,479
Operating income	366	359	347
Other income (expense), net	1	(2)	2
Allowance for funds used during construction — equity	4	33	27
Interest charges and financing costs			
Interest charges — includes other financing costs of $4, $4 and $3, respectively	114	119	99
Allowance for funds used during construction — debt	(2)	(14)	(12)
Total interest charges and financing costs	112	105	87
Income before income taxes	259	285	289
Income tax (benefit) expense	(59)	(10)	26
Net income	$ 318	$ 295	$ 263

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2021	2020	2019
Operating activities			
Net income	$ 318	$ 295	$ 263
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	303	298	232
Deferred income taxes	(47)	22	29
Allowance for equity funds used during construction	(4)	(33)	(27)
Provision for bad debts	6	6	6
Changes in operating assets and liabilities:			
Accounts receivable	(29)	(14)	(9)
Accrued unbilled revenues	(10)	—	(1)
Inventories	(21)	(35)	(21)
Prepayments and other	16	(14)	3
Accounts payable	4	8	(9)
Net regulatory assets and liabilities	(154)	(115)	14
Other current liabilities	(1)	13	6
Pension and other employee benefit obligations	(18)	(16)	(18)
Other, net	(4)	(1)	5
Net cash provided by operating activities	359	414	473
Investing activities			
Utility capital/construction expenditures	(580)	(1,142)	(844)
Investments in utility money pool arrangement	(83)	(4)	(133)
Receipts from utility money pool arrangement	83	4	133
Net cash used in investing activities	(580)	(1,142)	(844)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(113)	250	(42)
Proceeds from issuance of long-term debt, net	247	343	292
Borrowings under utility money pool arrangement	539	561	296
Repayments under utility money pool arrangement	(448)	(561)	(296)
Capital contributions from parent	301	438	426
Dividends paid to parent	(310)	(313)	(333)
Net cash provided by financing activities	216	718	343
Net change in cash and cash equivalents	(5)	(10)	(28)
Cash, cash equivalents and restricted cash at beginning of period	6	16	44
Cash, cash equivalents and restricted cash at end of period	$ 1	$ 6	$ 16
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (108)	$ (98)	$ (84)
Cash received for income taxes, net	21	10	12
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 37	$ 99	$ 95
Inventory transfers to property, plant and equipment	6	31	23
Operating lease right-of-use assets	—	—	548
Allowance for equity funds used during construction	4	33	27

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE CO.
BALANCE SHEETS
(amounts in millions, except share and per share data)

	Dec. 31 2021	Dec. 31 2020
Assets		
Current assets		
Cash and cash equivalents	$ 1	$ 6
Accounts receivable, net	115	94
Accounts receivable from affiliates	9	9
Accrued unbilled revenues	125	114
Inventories	51	36
Regulatory assets	193	76
Derivative instruments	30	10
Prepaid taxes	3	18
Prepayments and other	21	20
Total current assets	548	383
Property, plant and equipment, net	7,838	7,603
Other assets		
Regulatory assets	380	357
Derivative instruments	6	9
Operating lease right-of-use assets	463	492
Other	27	15
Total other assets	876	873
Total assets	$ 9,262	$ 8,859
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 137	$ 250
Borrowings under utility money pool arrangement	91	—
Accounts payable	172	198
Accounts payable to affiliates	16	17
Regulatory liabilities	54	57
Taxes accrued	47	54
Accrued interest	30	29
Dividends payable to parent	58	54
Derivative instruments	4	4
Operating lease liabilities	30	28
Other	24	25
Total current liabilities	663	716
Deferred credits and other liabilities		
Deferred income taxes	702	725
Regulatory liabilities	709	718
Asset retirement obligations	116	112
Derivative instruments	6	9
Pension and employee benefit obligations	8	42
Operating lease liabilities	434	463
Other	8	12
Total deferred credits and other liabilities	1,983	2,081
Commitments and contingencies		
Capitalization		
Long-term debt	3,013	2,764
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at Dec. 31, 2021 and Dec. 31, 2020, respectively	—	—
Additional paid in capital	3,091	2,790
Retained earnings	513	509
Accumulated other comprehensive loss	(1)	(1)
Total common stockholder's equity	3,603	3,298
Total liabilities and equity	$ 9,262	$ 8,859

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
Balance at Dec. 31, 2018	100	$ —	$ 1,932	$ 606	$ (1)	$ 2,537
Net income				263		263
Common dividends declared to parent				(334)		(334)
Contribution of capital by parent			419			419
Balance at Dec. 31, 2019	100	$ —	$ 2,351	$ 535	$ (1)	$ 2,885
Net income				295		295
Common dividends declared to parent				(321)		(321)
Contribution of capital by parent			439			439
Balance at Dec. 31, 2020	100	$ —	$ 2,790	$ 509	$ (1)	$ 3,298
Net income				318		318
Common dividends declared to parent				(314)		(314)
Contribution of capital by parent			301			301
Balance at Dec. 31, 2021	100	$ —	$ 3,091	$ 513	$ (1)	$ 3,603

See Notes to Financial Statements

SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements

1. Summary of Significant Accounting Policies

General — SPS is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity.

SPS' financial statements are presented in accordance with GAAP. All of SPS' underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions. Certain amounts in the financial statements or notes have been reclassified for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

SPS has evaluated events occurring after Dec. 31, 2021 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — SPS uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — SPS accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, SPS may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on SPS' results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — SPS accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. SPS defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. SPS uses rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of SPS' tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which would be refundable to utility customers over the remaining life of the related assets. SPS anticipates that a tax rate increase would result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal investment tax credits related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

SPS follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. SPS recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

SPS reports interest and penalties related to income taxes within other (expense) income or interest charges in the statements of income.

Xcel Energy Inc. and its subsidiaries, including SPS, file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation in Regulated Operations — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

SPS records depreciation expense using the straight-line method over the plant's commission-approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are recovered in rates as authorized by the appropriate regulatory entities. The amount of removal costs is based on current factors used in existing depreciation rates. Depreciation expense, expressed as a percentage of average depreciable property, was 3.3% in 2021, 3.1% in 2020 and 2.9% in 2019.

See Note 3 for further information.

AROs — SPS accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 10 for further information.

Benefit Plans and Other Postretirement Benefits — SPS maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 9 for further information.

Environmental Costs — Environmental costs are recorded when it is probable SPS is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for SPS' expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 10 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. SPS recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized.

SPS does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. SPS presents its revenues net of any excise or sales taxes or fees.

SPS participates in SPP. SPS recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO are recorded on a net basis in cost of sales.

See Note 6 for further information.

Cash and Cash Equivalents — SPS considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. SPS establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

As of Dec. 31, 2021 and 2020, the allowance for bad debts was $12 million and $8 million, respectively.

Inventory — Inventory is recorded at average cost and consisted of the following:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Inventories		
Materials and supplies	$ 29	$ 27
Fuel	22	9
Total inventories	$ 51	$ 36

Fair Value Measurements — SPS presents cash equivalents, interest rate derivatives and commodity derivatives at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, SPS may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the pension and postretirement plan assets published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 8 and 9 for further information.

Derivative Instruments — SPS uses derivative instruments in connection with its utility commodity price and interest rate activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on expected recovery of derivative instrument settlements through fuel and purchased energy cost recovery mechanisms. Interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — SPS enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

See Note 8 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in SPS' rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including DSM programs) qualify as alternative revenue programs. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate or from other instances where the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs — SPS has implemented programs in its jurisdictions to assist customers in conserving energy and reducing peak demand on the electric system. These programs include commercial motor, air conditioner and lighting upgrades, as well as residential rebates for participation in air conditioner interruption and home weatherization.

The costs incurred for some DSM programs are deferred as permitted by the applicable regulatory jurisdiction. For those programs, costs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Revenues recognized for incentive programs designed for recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned. SPS recovers approved conservation program costs in base rate revenue or through a rider.

Emission Allowances — Emission allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. SPS reduces recoverable fuel and purchased power costs for the cost of RECs received. An inventory accounting model is used to account for RECs recognized on the balance sheet, however these assets are classified as regulatory assets if amounts are recoverable in future rates.

Sales of RECs are recorded in electric revenues on a gross basis. Cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Segment Information — SPS has only one reportable segment. SPS is a wholly owned subsidiary of Xcel Energy Inc. and operates in the regulated electric utility industry providing wholesale and retail electric service in the states of Texas and New Mexico.

2. Accounting Pronouncements

Recently Adopted

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

SPS implemented the guidance using a modified-retrospective approach, recognizing an immaterial cumulative effect charge (after tax) to retained earnings on Jan. 1, 2020. The Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on SPS' financial statements.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Property, plant and equipment, net		
Electric plant	$ 9,639	$ 9,229
Plant to be retired [(a)]	299	316
CWIP	171	146
Total property, plant and equipment	10,109	9,691
Less accumulated depreciation	(2,271)	(2,088)
Property, plant and equipment, net	$ 7,838	$ 7,603

(a) Includes expected retirement of Tolk and conversion of Harrington to natural gas.

Table of Contents

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric rates. SPS would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2021		Dec. 31, 2020	
Regulatory Assets			**Current**	**Noncurrent**	**Current**	**Noncurrent**
Pension and retiree medical obligations	9	Various	$ 11	$ 135	$ 12	$ 178
Texas revenue surcharges		One to two years	20	64	54	17
Excess deferred taxes — TCJA	7	Various	2	50	3	51
Recoverable deferred taxes on AFUDC		Plant lives	—	41	—	42
Net AROs [(a)]	1, 10	Various	—	40	—	33
Losses on reacquired debt		Term of related debt	1	19	1	20
Conservation programs [(b)]	1	One to two years	3	2	1	2
Deferred natural gas and electric energy/fuel costs		One to three years	146	4	—	—
Other		Various	10	25	5	14
Total regulatory assets			$ 193	$ 380	$ 76	$ 357

(a) Includes amounts recorded for future recovery of AROs.
(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2021		Dec. 31, 2020	
Regulatory Liabilities			**Current**	**Noncurrent**	**Current**	**Noncurrent**
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 15	$ 486	$ 6	$ 513
Plant removal costs	1, 10	Various	—	190	—	177
Revenue subject to refund		One to two years	6	4	4	4
Gain from asset sales		Various	—	2	—	2
Deferred natural gas and electric energy/fuel costs		Less than one year	—	—	35	—
Contract valuation adjustments [(b)]	1, 8	One to three years	27	1	7	—
Other		Various	6	26	5	22
Total regulatory liabilities			$ 54	$ 709	$ 57	$ 718

(a) Includes the revaluation of recoverable/regulated plant accumulated deferred income taxes and revaluation impact of non-plant accumulated deferred income taxes due to the TCJA.
(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements..

At Dec. 31, 2021 and 2020, SPS' regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, SPS' regulatory assets included $292 million and $114 million at Dec. 31, 2021 and 2020, respectively, of past expenditures not earning a return. Amounts are related to the Texas deferred fuel balance, losses on reacquired debt and certain rate case expenditures.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2021	Year Ended Dec. 31		
		2021	**2020**	**2019**
Borrowing limit	$ 100	$ 100	$ 100	$ 100
Amount outstanding at period end	91	91	—	—
Average amount outstanding	100	51	43	8
Maximum amount outstanding	100	100	100	100
Weighted average interest rate, computed on a daily basis	0.05 %	0.05 %	0.54 %	2.42 %
Weighted average interest rate at end of period	0.05	0.05	N/A	N/A

Commercial Paper — Commercial paper outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2021	Year Ended Dec. 31 2021	2020	2019
Borrowing limit	$ 500	$ 500	$ 500	$ 400
Amount outstanding at period end	137	137	250	—
Average amount outstanding	69	63	44	72
Maximum amount outstanding	137	342	250	316
Weighted average interest rate, computed on a daily basis	0.17 %	0.21 %	1.11 %	2.68 %
Weighted average interest rate at end of period	0.26	0.26	0.29	N/A

Letters of Credit — SPS may use letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. At both Dec. 31, 2021 and 2020, there were $2 million of letters of credit outstanding under the credit facility. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an aggregate amount exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of SPS' credit facility:

Debt-to-Total Capitalization Ratio [(a)] 2021	2020	Amount Facility May Be Increased (millions of dollars)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
47%	48%	$50	2

(a) The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.
(b) All extension requests are subject to majority bank group approval.

The credit facility has a cross-default provision that SPS would be in default on its borrowings under the facility if SPS or any of its future significant subsidiaries whose total assets exceed 15% of SPS' total assets default on indebtedness in an aggregate principal amount exceeding $75 million.

If SPS does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2021, SPS was in compliance with all financial covenants.

SPS had the following committed credit facility available as of Dec. 31, 2021 (in millions) of dollars:

Credit Facility [(a)]	Drawn [(b)]	Available
$500	$139	$361

(a) This credit facility matures in June 2024.
(b) Includes letters of credit and outstanding commercial paper.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the facility outstanding at Dec. 31, 2021 and 2020.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of SPS is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long-term debt obligations for SPS as of Dec. 31 (in millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	3.30 %	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds	4.40	Nov. 15, 2048	300	300
First mortgage bonds	3.75	June 15, 2049	300	300
First mortgage bonds [(b)]	3.15	May 1, 2050	350	350
First mortgage bonds [(a)]	3.15	May 1, 2050	250	—
Unamortized discount			(9)	(10)
Unamortized debt issuance cost			(28)	(26)
Total long-term debt			$ 3,013	$ 2,764

(a) 2020 financing re-opened in 2021.
(b) 2020 financing.

Maturities of long-term debt:

(Millions of Dollars)	
2022	$ —
2023	—
2024	350
2025	—
2026	—

Deferred Financing Costs — Deferred financing costs of approximately $28 million and $26 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2021 and 2020, respectively. SPS is amortizing these financing costs over the remaining maturity periods of the related debt.

Capital Stock — SPS has the following preferred stock:

Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2021 and 2020
10,000,000	1.00	—

Dividend Restrictions — SPS dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. SPS is required to be current on particular interest payments before dividends can be paid.

SPS' state regulatory commissions additionally impose dividend limitations, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2021:

Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual [(a)]
Low	High	2021
45.0 %	55.0 %	54.5 %

(a) Excludes short-term debt.

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization [(a)]
$ 513 million	$ 6,615 million	N/A

(a) SPS may not pay a dividend that would cause it to lose its investment grade bond rating.

6. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consisted of the following:

	Year Ended Dec. 31		
(Millions of Dollars)	2021	2020	2019
Major revenue types			
Revenue from contracts with customers:			
Residential	$ 375	$ 359	$ 352
C&I	842	739	800
Other	38	39	41
Total retail	1,255	1,137	1,193
Wholesale	873	345	361
Transmission	287	279	240
Other	6	4	3
Total revenue from contracts with customers	2,421	1,765	1,797
Alternative revenue and other	44	105	29
Total revenues	$ 2,465	$ 1,870	$ 1,826

7. Income Taxes

Federal Tax Loss Carryback Claims — In 2020, Xcel Energy identified certain expenses related to tax years 2009 - 2011 that qualify for an extended carryback claim. SPS is not expected to accrue any income tax expense related to this adjustment.

Federal Audit — SPS is a member of Xcel Energy affiliated group that files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's consolidated federal tax returns expire as follows:

Tax Year(s)	Expiration
2014 - 2016	December 2022
2018	September 2022

Additionally, the statute of limitations related to the federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to the additional federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2021, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2016. In April 2021, Texas began an audit of tax years 2016 - 2019. As of Dec. 31, 2021, no material adjustments have been proposed.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the timing of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	$ 4	$ 3
Unrecognized tax benefit — Temporary tax positions	4	4
Total unrecognized tax benefit	$ 8	$ 7

Changes in unrecognized tax benefits:

(Millions of Dollars)	2021	2020	2019
Balance at Jan. 1	$ 7	$ 5	$ 5
Additions based on tax positions related to the current year	1	1	—
Additions for tax positions of prior years	—	5	—
Reductions for tax positions of prior years	—	(4)	—
Balance at Dec. 31	$ 8	$ 7	$ 5

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	$ (7)	$ (6)

As the IRS progresses its review of the tax loss carryback claim and as state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $5 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2021	2020	2019
(Payable) receivable for interest related to unrecognized tax benefits at Jan. 1	$ (1)	$ 1	$ 1
Interest expense related to unrecognized tax benefits	—	(2)	—
(Payable) receivable for interest related to unrecognized tax benefits at Dec. 31	$ (1)	$ (1)	$ 1

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2021, 2020 or 2019.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2021	2020
Federal NOL carryforward	$ 336	$ —
Federal tax credit carryforwards	187	83
State NOL carryforwards	111	1

Federal carryforward periods expire between 2031 and 2041 and state carryforward periods expire starting 2034.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2021	2020 [a]	2019 [a]
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	2.5	2.3	2.2
Increases (decreases) in tax from:			
Wind PTCs	(39.7)	(18.3)	(7.9)
Plant regulatory differences [b]	(4.8)	(6.4)	(5.0)
Amortization of excess nonplant deferred taxes	(1.1)	(0.8)	(0.9)
Change in unrecognized tax benefits	0.5	0.3	0.2
Other, net	(1.2)	(1.6)	(0.6)
Effective income tax rate	(22.8)%	(3.5)%	9.0 %

[a] Prior periods have been reclassified to conform to current year presentation.

[b] Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2021	2020	2019
Current federal tax benefit	$ (11)	$ (31)	$ (4)
Current state tax (benefit) expense	(1)	(1)	1
Current change in unrecognized tax expense	—	—	—
Deferred federal tax (benefit) expense	(57)	13	22
Deferred state tax expense	9	8	6
Deferred change in unrecognized tax expense	1	1	1
Total income tax (benefit) expense	$ (59)	$ (10)	$ 26

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2021	2020	2019
Deferred tax (benefit) expense excluding items below	$ (23)	$ 53	$ 53
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(24)	(31)	(24)
Deferred tax (benefit) expense	$ (47)	$ 22	$ 29

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2021	2020 [a]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 942	$ 838
Operating lease assets	103	109
Regulatory assets	65	59
Deferred fuel costs	34	(9)
Pension expense	34	33
Other	2	2
Total deferred tax liabilities	$ 1,180	$ 1,032
Deferred tax assets:		
Operating lease liabilities	$ 103	$ 109
Regulatory liabilities	98	104
Tax credit carryforward	187	83
NOL carryforward	76	—
Other employee benefits	7	7
Other	7	4
Total deferred tax assets	478	307
Net deferred tax liability	$ 702	$ 725

[a] Prior periods have been reclassified to conform to current year presentation.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as FTRs, purchased from SPP. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of Dec. 31, 2021, accumulated other comprehensive loss related to settled interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings. As of Dec. 31, 2021, SPS had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Gross notional amounts of FTRs:

(Amounts in Millions) [a]	Dec. 31, 2021	Dec. 31, 2020
MWh of electricity	8	5

[a] Amounts are not reflective of net positions in the underlying commodities.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. At Dec. 31, 2021, two of the eight most significant counterparties for these activities, comprising $8 million or 24% of this credit exposure, had investment grade ratings from S&P, Moody's or Fitch Ratings. Five of the eight most significant counterparties, comprising $26 million or 76% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount or less than 1% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — Changes in the fair value of FTRs resulting in a pre-tax net gain of $28 million and $7 million in Dec. 31, 2021 and 2019, respectively and $7 million in pre-tax net losses in the year ended Dec. 31, 2020, were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains were $20 million and $6 million for the years ended Dec. 31, 2021 and 2019, respectively. For the year ended Dec. 31, 2020, FTR settlement losses were immaterial. Settlement gains and losses were recognized and recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2021, 2020 and 2019.

Table of Contents

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value			Fair Value Total	Netting (a)	Total	Fair Value			Fair Value Total	Netting (a)	Total
(Millions of Dollars)	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 27	$ 27	$ —	$ 27	$ —	$ —	$ 7	$ 7	$ —	$ 7
Total current derivative assets	$ —	$ —	$ 27	$ 27	$ —	27	$ —	$ —	$ 7	$ 7	$ —	7
PPAs (b)						3						3
Current derivative instruments						$ 30						$ 10
Noncurrent derivative assets												
PPAs (b)						$ 6						$ 9
Noncurrent derivative instruments						$ 6						$ 9
Current derivative liabilities												
Other derivative instruments:												
PPAs (b)						$ 4						$ 4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs (b)						$ 6						$ 9
Noncurrent derivative instruments						$ 6						$ 9

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2021 and 2020. At Dec. 31, 2021 and 2020, derivative assets and liabilities include no obligations to return cash collateral, respectively. At Dec. 31, 2021 and 2020, derivative assets and liabilities include no rights to reclaim cash collateral, respectively. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2021, 2020 and 2019:

	Year Ended Dec. 31		
(Millions of Dollars)	2021	2020	2019
Balance at Jan. 1	$ 7	$ 12	$ 14
Purchases	10	23	27
Settlements	(79)	(23)	(34)
Net transactions recorded during the period:			
Net gains (losses) recognized as regulatory assets	89	(5)	5
Balance at Dec. 31	$ 27	$ 7	$ 12

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for Dec. 31, 2021, 2020 and 2019.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2021		2020	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 3,013	$ 3,454	$ 2,764	$ 3,381

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2021 and 2020, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

9. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy, which includes SPS, has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits. The average annual interest crediting rates for these plans was 2.35, 2.37 and 3.12 percent in 2021, 2020, and 2019, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2021 and 2020 were $43 million and $43 million, respectively, of which $2 million was attributable to SPS in both years. In 2021 and 2020, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million and $6 million, respectively, of which immaterial amounts were attributable to SPS.

Xcel Energy, which includes SPS, investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as long-term projected return levels. 20 years or longer period, as well as long-term projected return levels. Xcel Energy and SPS continually review pension assumptions.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2021 were above the assumed level of 6.39%.
- Investment returns in 2020 were above the assumed level of 6.78%.
- Investment returns in 2019 were above the assumed level of 6.78%.
- In 2022, SPS's expected investment-return assumption is 6.39%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations consider many factors and generally result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, SPS' pension plan assets measured at fair value:

	Dec. 31, 2021 [(a)]					Dec. 31, 2020 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 20	$ —	$ —	$ —	$ 20	$ 31	$ —	$ —	$ —	$ 31
Commingled funds	202	—	—	169	371	211	—	—	160	371
Debt securities	—	148	1	—	149	—	110	1	—	111
Equity securities	10	—	—	—	10	11	—	—	—	11
Other	—	2	—	5	7	2	1	—	—	3
Total	$ 232	$ 150	$ 1	$ 174	$ 557	$ 255	$ 111	$ 1	$ 160	$ 527

(a) See Note 8 for further information on fair value measurement inputs and methods.

For each of the fair value hierarchy levels, SPS' proportionate allocation of the total postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2021 [(a)]					Dec. 31, 2020 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 3	$ —	$ —	$ —	$ 3	$ 3	$ —	$ —	$ —	$ 3
Insurance contracts	—	5	—	—	5	—	5	—	—	5
Commingled funds	6	—	—	7	13	7	—	—	7	14
Debt securities	—	22	—	—	22	—	22	—	—	22
Total	$ 9	$ 27	$ —	$ 7	$ 43	$ 10	$ 27	$ —	$ 7	$ 44

(a) See Note 8 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2021 or 2020.

Table of Contents

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2020 to Dec. 31, 2021, due primarily to benefit payments and increases in discount rates used in actuarial valuations. Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for SPS are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2021**	**2020**	**2021**	**2020**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 562	$ 519	$ 38	$ 44
Service cost	11	10	1	1
Interest cost	15	18	1	1
Plan amendments	—	—	—	—
Actuarial (gain) loss	(13)	45	(3)	(5)
Plan participants' contributions	—	—	—	1
Benefit payments	(30)	(30)	(3)	(4)
Obligation at Dec. 31	$ 545	$ 562	$ 34	$ 38
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 527	$ 458	$ 44	$ 44
Actual return on plan assets	46	84	1	3
Employer contributions	14	15	—	—
Plan participants' contributions	—	—	1	1
Benefit payments	(30)	(30)	(3)	(4)
Fair value of plan assets at Dec. 31	$ 557	$ 527	$ 43	$ 44
Funded status of plans at Dec. 31	$ 12	$ (35)	$ 9	$ 6
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent assets	12	—	9	6
Noncurrent liabilities	—	(35)	—	—
Net amounts recognized	$ 12	$ (35)	$ 9	$ 6

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	**2021**	**2020**	**2021**	**2020**
Discount rate for year-end valuation	3.08 %	2.71 %	3.09 %	2.65 %
Expected average long-term increase in compensation level	3.75 %	3.75 %	N/A	N/A
Mortality table	Pri-2012	Pri-2012	Pri-2012	Pri-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	5.30 %	5.50 %
Health care costs trend rate — initial: Post-65	N/A	N/A	4.90 %	5.00 %
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50 %	4.50 %
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50 %	4.50 %
Years until ultimate trend is reached	N/A	N/A	4	5

Accumulated benefit obligation for the pension plan was $506 million and $519 million as of Dec. 31, 2021 and 2020, respectively.

Table of Contents

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income (expense) in the statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	**2021**	**2020**	**2019**	**2021**	**2020**	**2019**
Service cost	$ 11	$ 10	$ 9	$ 1	$ 1	$ 1
Interest cost	15	18	20	1	1	2
Expected return on plan assets	(30)	(29)	(28)	(2)	(2)	(2)
Amortization of prior service credit	—	—	—	—	—	(1)
Amortization of net loss	14	12	11	(1)	—	—
Settlement charge [(a)]	—	—	2	—	—	—
Net periodic pension cost	10	11	14	(1)	—	—
Effects of regulation	—	2	1	—	—	—
Net benefit cost recognized for financial reporting	$ 10	$ 13	$ 15	$ (1)	$ —	$ —
Significant Assumptions Used to Measure Costs:						
Discount rate	2.71 %	3.49 %	4.31 %	2.65 %	3.47 %	4.32 %
Expected average long-term increase in compensation level	3.75	3.75	3.75	— %	—	—
Expected average long-term rate of return on assets	6.39	6.78	6.78	4.10	4.50	5.30

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2019, as a result of lump-sum distributions during each plan year, SPS recorded a total pension settlement charge of $2 million. A total of $1 million of that amount was recorded in the income statement in 2019. There were no settlement charges recorded to the qualified pension plans in 2021 or 2020.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2021**	**2020**	**2021**	**2020**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 143	$ 186	$ (19)	$ (18)
Prior service credit	(1)	(1)	(1)	(1)
Total	$ 142	$ 185	$ (20)	$ (19)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 11	$ 11	$ —	$ —
Noncurrent regulatory assets	131	174	—	—
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(19)	(18)
Total	$ 142	$ 185	$ (20)	$ (19)
Measurement date	Dec. 31, 2021	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2020

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2019 - 2022 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $50 million in January 2022, of which none was attributable to SPS.
- $131 million in 2021, of which $15 million was attributable to SPS.
- $150 million in 2020, of which $14 million was attributable to SPS.
- $154 million in 2019, of which $18 million was attributable to SPS.

For future years, Xcel Energy and SPS anticipate contributions will be made as necessary.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy's voluntary postretirement funding contributions were as follows:

- $9 million during 2022.
- $15 million during 2021.
- $11 million during 2020.
- $15 million during 2019.
- Amounts attributable to SPS were immaterial.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Domestic and international equity securities	33 %	35 %	15 %	15 %
Long-duration fixed income securities	37	35	—	—
Short-to-intermediate fixed income securities	11	13	71	72
Alternative investments	17	15	8	9
Cash	2	2	6	4
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year

Plan Amendments — In 2020 and 2019, there were no significant plan amendments made which affected the benefit obligation.

In 2021, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

Projected Benefit Payments

SPS' projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2022	$ 33	$ 3	$ —	$ 3
2023	31	2	—	2
2024	31	2	—	2
2025	32	2	—	2
2026	31	2	—	2
2027-2031	153	11	—	11

Defined Contribution Plans

Xcel Energy, which includes SPS, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for SPS was approximately $3 million in 2021, 2020 and 2019.

10. Commitments and Contingencies

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

Rate Matters

SPS is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the financial statements.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates. The timing of these refunds is uncertain.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. FERC has asked that this appeal be stayed until early 2022, in order to provide FERC with time to issue an order on SPS' April 2018 rehearing request. FERC's order is expected in the first quarter of 2022. The D.C. Circuit appeal may resume after that FERC order is issued.

Wind Operating Commitments — PUCT and NMPRC orders related to the Hale and Sagamore wind projects included certain operating and savings minimums. In general, annual generation must exceed a net capacity factor of 48%. If annual generation is below the guaranteed level, SPS would be obligated to refund an amount equal to foregone PTCs and fuel savings. Additionally, retail customer savings must exceed project costs included in base rates over the first ten years of operations. SPS would be required to refund excess costs, if any, after ten years of operations. As of Dec. 31, 2021, the full-year net capacity factor was 48.4%, resulting in no refund liability for 2021.

Contract Termination — SPS and LP&L are parties to a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the ERCOT (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million (lump sum or annual installments), to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The settlement agreement is subject to approval by the PUCT and FERC.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for SPS, which are normally recovered through the regulated rate process.

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. SPS may sometimes pay all or a portion of the cost to remediate sites where past activities of SPS' predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which SPS is alleged to have sent wastes to that site.

Historical MGP, Landfill and Disposal Sites

SPS is remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities from final resolution of these issues; however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Federal CWA Waters of the U.S. Rule — SPS is monitoring ongoing changes to the definition of Waters of the U.S. under the CWA. Regardless of which definition is applicable in the states in which we operate, SPS does not anticipate that compliance costs will be material.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. In October 2020, the EPA published a final rule revising the regulations. SPS anticipates that compliance costs will not be material and will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. Texas' first regional haze plan has undergone federal review.

All states are now subject to a second round of regional haze planning/rulemaking, focusing on additional reductions to meet reasonable progress requirements. Any additional impacts to SPS facilities are expected to be minimal.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the D.C. Circuit that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking. The EPA reaffirmed the rule in August 2020 with minor changes.

The 2020 EPA Action has been challenged. All pending actions could be consolidated and may proceed in the Fifth Circuit or the D.C. Circuit, where a parallel challenge has been filed. The timing of final decisions is unclear.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule referenced above are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule.

Implementation of the NAAQS for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with one exception. The EPA issued final designations, which found the area near the Harrington plant as "unclassifiable." The area near the Harrington plant was monitored for the three years ending in 2019 and the monitoring showed the area to be exceeding the standard.

To address this issue, 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.

SPS believes compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for SPS' assets.

SPS' AROs were as follows:

(Millions of Dollars)	2021 Jan. 1, 2021	2021 Accretion	2021 Dec. 31, 2021 [(a)]
Electric			
Steam and other production	$ 52	$ 2	$ 54
Wind	50	2	52
Distribution	10	—	10
Total liability	$ 112	$ 4	$ 116

(a) There were no ARO amounts incurred, settled or revised in 2021.

(Millions of Dollars)	2020 Jan. 1, 2020	Amounts Incurred [(a)]	Amounts Settled [(b)]	Accretion	Dec. 31, 2020 [(c)]
Electric					
Steam and other production	$ 51	$ —	$ (2)	$ 3	$ 52
Wind	16	33	—	1	50
Distribution	10	—	—	—	10
Total liability	$ 77	$ 33	$ (2)	$ 4	$ 112

(a) Amounts incurred related to the Sagamore wind farm placed in service in 2020.
(b) Amounts settled related to asbestos abatement projects.
(c) No AROs were revised in 2020.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of SPS' facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2021. Therefore, an ARO has not been recorded for these facilities.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent SPS' rights to use leased assets. The present value of future operating lease payments is recognized in current and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of SPS' leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the estimated incremental borrowing rate (weighted average of 4.4%). SPS has elected to utilize the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure. Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
PPAs	$ 500	$ 500
Other	45	50
Gross operating lease ROU assets	545	550
Accumulated amortization	(82)	(58)
Net operating lease ROU assets	$ 463	$ 492

Components of lease expense:

(Millions of Dollars)	2021	2020	2019
Operating leases			
PPA capacity payments	$ 53	$ 48	$ 48
Other operating leases [(a)]	4	3	5
Total operating lease expense [(b)]	$ 57	$ 51	$ 53

(a) Includes short-term lease expense of $1 million, $1 million and $2 million for 2021, 2020 and 2019, respectively.
(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense.

Commitments under operating leases as of Dec. 31, 2021:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases
2022	$ 46	$ 3	$ 49
2023	46	3	49
2024	46	3	49
2025	46	4	50
2026	46	4	50
Thereafter	312	40	352
Total minimum obligation	542	57	599
Interest component of obligation	(120)	(15)	(135)
Present value of minimum obligation	422	42	464
Less current portion			(30)
Noncurrent operating and finance lease liabilities			$ 434
Weighted-average remaining lease term in years			12

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.
(b) PPA operating leases contractually expire at various dates through 2033.

PPAs and Fuel Contracts

Non-Lease PPAs — SPS has entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2024, contain minimum energy purchase requirements.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts, were payments for capacity of $12 million, $12 million and $20 million in 2021, 2020 and 2019, respectively.

At Dec. 31, 2021, the estimated future payments for capacity that SPS is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity
2022	$ 12
2023	12
2024	6
2025	—
2026	—
Thereafter	—
Total	$ 30

Fuel Contracts — SPS has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal and natural gas requirements. These contracts expire between 2022 and 2033. SPS is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2021:

(Millions of Dollars)	Coal	Natural gas supply	Natural gas storage and transportation
2022	$ 211	$ 44	$ 32
2023	50	—	29
2024	31	—	16
2025	—	—	12
2026	—	—	6
Thereafter	—	—	14
Total	$ 292	$ 44	$ 109

VIEs

PPAs — Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that it purchases. SPS has determined that certain IPPs are VIEs. SPS is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

SPS evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance.

SPS had approximately 1,197 MW of capacity under long-term PPAs at both Dec. 31, 2021 and 2020 with entities that have been determined to be VIEs. These agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO Inc. under contracts that will expire in December 2022. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs. SPS has determined that TUCO is a VIE. SPS has concluded that it is not the primary beneficiary of TUCO, because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

11. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including SPS. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. SPS uses services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy, Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS have established a utility money pool arrangement.

See Note 5 for further information.

Significant affiliate transactions among the companies and related parties for the years ended Dec. 31:

(Millions of Dollars)	2021	2020	2019
Operating expenses:			
Other operating expenses — paid to Xcel Energy Services Inc.	$ 209	$ 200	$ 192

Accounts receivable and payable with affiliates at Dec. 31 were:

	2021		2020	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 2	$ —	$ 3	$ —
PSCo	7	—	6	—
Other subsidiaries of Xcel Energy Inc.	—	16	—	17
	$ 9	$ 16	$ 9	$ 17

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure. As of Dec. 31, 2021, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during SPS' most recent fiscal quarter ended Dec. 31, 2021 that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting. SPS maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. SPS has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level.

During the year and in preparation for issuing its report for the year ended Dec. 31, 2021 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, SPS conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, SPS did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in SPS' Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

This annual report does not include an attestation report of SPS' independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by SPS' independent registered public accounting firm pursuant to the rules of the SEC that permit SPS to provide only management's report in this annual report.

ITEM 9B — OTHER INFORMATION

None.

ITEM 9C — DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

Items 10, 11, 12 and 13 of Part III of Form 10-K have been omitted from this report for SPS in accordance with conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly-owned subsidiaries.

ITEM 10 — DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

ITEM 11 — EXECUTIVE COMPENSATION

ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s definitive Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item (aggregate fees billed to us by our principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34)) is contained in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

ITEM 15 — EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

1	Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2021.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Statements of Income — For each of the three years ended Dec. 31, 2021, 2020 and 2019.
	Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2021, 2020 and 2019.
	Statements of Cash Flows — For each of the three years ended Dec. 31, 2021, 2020 and 2019.
	Balance Sheets — As of Dec. 31, 2021 and 2020.
	Statements of Common Stockholder's Equity — For each of the three years ended Dec. 31, 2021, 2020 and 2019.
2	Schedule II — Valuation and Qualifying Accounts and Reserves for each of the years ended Dec. 31, 2021, 2020 and 2019.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	3.01
3.02*	By-Laws of SPS as Amended and Restated on Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	3.02
4.01*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	99.2
4.02*	Supplemental Indenture dated Oct. 1, 2003 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of 6% Series C and Series D Notes due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	4.04
4.03*	Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee, creating $200 million principal amount of 5.6% Series E Notes due 2016 and $250 million principal amount of 6% Series F Notes due 2036	SPS Form 8-K dated Oct. 3, 2006	4.01
4.04*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	4.01
4.05*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series due 2041	SPS Form 8-K dated Aug. 10, 2011	4.02

Table of Contents

4.06*	Supplemental Indenture dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	SPS Form 8-K dated June 9, 2014	4.02
4.07*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series due 2046	SPS Form 8-K dated Aug. 12, 2016	4.02
4.08*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series due 2047	SPS Form 8-K dated Aug. 9, 2017	4.02
4.09*	Supplemental Indenture dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 4.40% First Mortgage Bonds, Series due 2048	SPS Form 8-K dated Nov. 5, 2018	4.02
4.10*	Supplemental Indenture dated as of June 1, 2019 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.75% First Mortgage Bonds, Series due 2049	SPS Form 8-K dated June 18, 2019	4.02
4.11*	Supplemental Indenture No. 8, dated as of May 1, 2020 between SPS and U.S. Bank National Association, as Trustee, creating $600 million principal amount of 3.15% First Mortgage Bonds, Series due 2050	SPS Form 8-K dated May 18, 2020	4.02
10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.05
10.03*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.18
10.04*+	Fifth Amendment to Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	10.01
10.05*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	10.01
10.06*+	Eighth Amendment to Exhibit 10.02 dated March 31, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2020	10.02
10.07*+	Ninth Amendment to Exhibit 10.02 dated May 22, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2020	10.01
10.08*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.17
10.09*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	Appendix A
10.10*+	First Amendment to Exhibit 10.09 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	10.01
10.11*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	10.08
10.12*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.07
10.13*+	First Amendment to Exhibit 10.12 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.17
10.14*+	Second Amendment to Exhibit 10.12 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	10.22
10.15*+	Third Amendment to Exhibit 10.12 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	10.01
10.16*+	Fourth Amendment to Exhibit 10.12 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	10.1
10.17*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.34
10.18*+	Form of Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan for Awards of Restricted Stock Units and/or Performance Share Units	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.35
10.19*+	Form of Award Agreement for Restricted Stock Units and/or Performance Share Units under the Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement for awards since 2020	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	10.32
10.20*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	Appendix A
10.21*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 26, 2015	10.02
10.22*+	Summary of Non-Employee Director Compensation, effective as of Oct. 1, 2021	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2021	10.01
10.23*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.36
10.24*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	H-1
10.25*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.04
23.01	Consent of Independent Registered Public Accounting Firm.		
31.01	Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document		

101.SCH	Inline XBRL Schema
101.CAL	Inline XBRL Calculation
101.DEF	Inline XBRL Definition
101.LAB	Inline XBRL Label
101.PRE	Inline XBRL Presentation
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

SCHEDULE II

Southwestern Public Service Co. Valuation and Qualifying Accounts
Years Ended Dec. 31

	Allowance for bad debts		
(Millions of Dollars)	**2021**	**2020**	**2019**
Balance at Jan. 1	$ 8	$ 5	$ 6
Additions charged to costs and expenses	6	6	6
Additions charged to other accounts [(a)]	3	2	2
Deductions from reserves [(b)]	(5)	(5)	(9)
Balance at Dec. 31	$ 12	$ 8	$ 5

(a) Recovery of amounts previously written-off.
(b) Deductions related primarily to bad debt write-offs.

ITEM 16 — FORM 10-K SUMMARY

None.

Table of Contents

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

	SOUTHWESTERN PUBLIC SERVICE COMPANY
Feb. 23, 2022	/s/ BRIAN J. VAN ABEL
	Brian J. Van Abel Executive Vice President, Chief Financial Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

/s/ ROBERT C. FRENZEL	/s/ DAVID T. HUDSON
Robert C. Frenzel Chairman, Chief Executive Officer and Director (Principal Executive Officer)	David T. Hudson President and Director
/s/ BRIAN J. VAN ABEL	/s/ JEFFREY S. SAVAGE
Brian J. Van Abel Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	Jeffrey S. Savage Senior Vice President, Controller (Principal Accounting Officer)

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

SPS has not sent, and does not expect to send, an annual report or proxy statement to its security holder.

2022 Form 10-Q

For the Quarterly Period Ended

March 31, 2022

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2022

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-03789

Southwestern Public Service Company
(Exact Name of Registrant as Specified in its Charter)

New Mexico	**75-0575400**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
790 South Buchanan Street Amarillo Texas	**79101**
(Address of Principal Executive Offices)	(Zip Code)

(303) 571-7511
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 28, 2022
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

TABLE OF CONTENTS

This Form 10-Q is filed by SPS, a New Mexico corporation. SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

Table of Contents

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Other

BART	Best available retrofit technology
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
ETR	Effective tax rate
FTR	Financial transmission right
GAAP	United States generally accepted accounting principles
IPP	Independent power producing entity
LP&L	Lubbock Power and Light
OATT	Open access transmission tariff
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.

Measurements

MW	Megawatts

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed in SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 and subsequent filings with the SEC, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including potential impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Code of Conduct; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints, and their impact on capital expenditures and/or the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties; and regulatory changes and/or limitations related to the use of natural gas as an energy source.

Table of Contents

PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31	
	2022	2021
Operating revenues	$ 477	$ 934
Operating expenses		
Electric fuel and purchased power	237	693
Operating and maintenance expenses	72	71
Demand side management expenses	5	4
Depreciation and amortization	78	78
Taxes (other than income taxes)	25	21
Total operating expenses	417	867
Operating income	60	67
Other income, net	—	1
Allowance for funds used during construction — equity	—	1
Interest charges and financing costs		
Interest charges — includes other financing costs of $1 and $1, respectively	29	30
Total interest charges and financing costs	29	30
Income before income taxes	31	39
Income tax benefit	(21)	(19)
Net income	$ 52	$ 58

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31	
	2022	**2021**
Operating activities		
Net income	$ 52	$ 58
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	79	79
Deferred income taxes	(2)	(19)
Allowance for equity funds used during construction	—	(1)
Provision for bad debts	2	2
Changes in operating assets and liabilities:		
Accounts receivable	(26)	(1)
Accrued unbilled revenues	—	3
Inventories	(6)	(17)
Prepayments and other	(8)	21
Accounts payable	—	56
Net regulatory assets and liabilities	3	(95)
Other current liabilities	(3)	(3)
Pension and other employee benefit obligations	1	(15)
Other, net	(3)	(2)
Net cash provided by operating activities	89	66
Investing activities		
Utility capital/construction expenditures	(123)	(172)
Investments in utility money pool arrangement	—	(83)
Repayments from utility money pool arrangement	—	83
Net cash used in investing activities	(123)	(172)
Financing activities		
Proceeds from (repayments of) short-term borrowings, net	75	(250)
Proceeds from issuance of long-term debt, net	—	247
Borrowings under utility money pool arrangement	202	213
Repayments under utility money pool arrangement	(193)	(213)
Capital contributions from parent	8	304
Dividends paid to parent	(58)	(54)
Net cash provided by financing activities	34	247
Net change in cash, cash equivalents and restricted cash	—	141
Cash, cash equivalents and restricted cash at beginning of period	1	6
Cash, cash equivalents and restricted cash at end of period	$ 1	$ 147
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (21)	$ (19)
Cash received for income taxes, net	3	14
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 38	$ 54
Inventory transfers to property, plant and equipment	4	7
Allowance for equity funds used during construction	—	1

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	March 31, 2022	Dec. 31, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable, net	137	115
Accounts receivable from affiliates	10	9
Accrued unbilled revenues	125	125
Inventories	53	51
Regulatory assets	130	193
Derivative instruments	30	30
Prepaid taxes	20	3
Prepayments and other	11	21
Total current assets	517	548
Property, plant and equipment, net	7,891	7,838
Other assets		
Regulatory assets	447	380
Derivative instruments	10	6
Operating lease right-of-use assets	456	463
Other	28	27
Total other assets	941	876
Total assets	$ 9,349	$ 9,262
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 212	$ 137
Borrowings under utility money pool arrangement	100	91
Accounts payable	172	172
Accounts payable to affiliates	18	16
Regulatory liabilities	52	54
Taxes accrued	33	47
Accrued interest	38	30
Dividends payable to parent	53	58
Derivative instruments	4	4
Operating lease liabilities	30	30
Other	27	24
Total current liabilities	739	663
Deferred credits and other liabilities		
Deferred income taxes	703	702
Regulatory liabilities	721	709
Asset retirement obligations	117	116
Derivative instruments	5	6
Pension and employee benefit obligations	8	8
Operating lease liabilities	426	434
Other	7	8
Total deferred credits and other liabilities	1,987	1,983
Commitments and contingencies		
Capitalization		
Long-term debt	3,013	3,013
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at March 31, 2022 and Dec. 31, 2021, respectively	—	—
Additional paid in capital	3,099	3,091
Retained earnings	512	513
Accumulated other comprehensive loss	(1)	(1)
Total common stockholder's equity	3,610	3,603
Total liabilities and equity	$ 9,349	$ 9,262

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended March 31, 2022 and 2021						
Balance at Dec. 31, 2020	100	$ —	$ 2,790	$ 509	$ (1)	$ 3,298
Net income				58		58
Dividends declared to parent				(52)		(52)
Contributions of capital by parent			304			304
Balance at March 31, 2021	100	$ —	$ 3,094	$ 515	$ (1)	$ 3,608
Balance at Dec. 31, 2021	100	$ —	$ 3,091	$ 513	$ (1)	$ 3,603
Net income				52		52
Dividends declared to parent				(53)		(53)
Contributions of capital by parent			8			8
Balance at March 31, 2022	100	$ —	$ 3,099	$ 512	$ (1)	$ 3,610

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with GAAP, the financial position of SPS as of March 31, 2022 and Dec. 31, 2021; the results of SPS' operations, including the components of net income and changes in stockholder's equity for the three months ended March 31, 2022 and 2021; and SPS' cash flows for the three months ended March 31, 2022 and 2021.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2022 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2021 balance sheet information has been derived from the audited 2021 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021.

Notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021, filed with the SEC on Feb. 23, 2022.

Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

As of March 31, 2022, there was no material impact from the recent adoption of new accounting pronouncements, nor expected material impact from recently issued accounting pronouncements yet to be adopted, on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	March 31, 2022	Dec. 31, 2021
Accounts receivable, net		
Accounts receivable	$ 149	$ 127
Less allowance for bad debts	(12)	(12)
Accounts receivable, net	$ 137	$ 115

(Millions of Dollars)	March 31, 2022	Dec. 31, 2021
Inventories		
Materials and supplies	$ 34	$ 29
Fuel	19	22
Total inventories	$ 53	$ 51

(Millions of Dollars)	March 31, 2022	Dec. 31, 2021
Property, plant and equipment, net		
Electric plant	$ 9,734	$ 9,639
Plant to be retired [(a)]	285	299
CWIP	195	171
Total property, plant and equipment	10,214	10,109
Less accumulated depreciation	(2,323)	(2,271)
Property, plant and equipment, net	$ 7,891	$ 7,838

(a) Includes expected retirement of Tolk and conversion of Harrington to natural gas.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	100	91
Average amount outstanding	67	51
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	0.13 %	0.05 %
Weighted average interest rate at period end	0.19	0.05

Commercial Paper — Commercial paper outstanding for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	212	137
Average amount outstanding	233	63
Maximum amount outstanding	324	342
Weighted average interest rate, computed on a daily basis	0.39 %	0.21 %
Weighted average interest rate at period end	0.83	0.26

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. At both March 31, 2022 and Dec. 31, 2021, there were $2 million of letters of credit outstanding under the credit facility. Amounts approximate their fair value and are subject to fees.

Revolving Credit Facility — In order to issue its commercial paper, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper exceeding available capacity under this credit facility. The credit facility provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Table of Contents

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of March 31, 2022, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 214	$ 286

(a) Expires in June 2024.
(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of March 31, 2022 and Dec. 31, 2021.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consisted of the following:

	Three Months Ended March 31	
(Millions of Dollars)	**2022**	**2021**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 97	$ 91
Commercial and Industrial	222	189
Other	8	9
Total retail	327	289
Wholesale	69	558
Transmission	72	71
Other	3	2
Total revenue from contracts with customers	471	920
Alternative revenue and other	6	14
Total revenues	$ 477	$ 934

6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2021 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

Difference between the statutory rate and ETR:

	Three Months Ended March 31	
	2022	**2021**
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.5	2.6
Decreases in tax from:		
Wind PTCs	(87.2)	(65.5)
Plant regulatory differences [(a)]	(4.0)	(4.7)
Amortization of excess nonplant deferred taxes	(1.1)	(1.2)
Other (net)	1.1	(0.9)
Effective income tax rate	(67.7)%	(48.7)%

(a) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as FTRs, purchased from SPP. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

Table of Contents

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of March 31, 2022, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings. As of March 31, 2022, SPS had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Amounts in Millions [(a)]	March 31, 2022	Dec. 31, 2021
Megawatt hours of electricity	10	8

(a) Amounts are not reflective of net positions in the underlying commodities.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts, prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

At March 31, 2022, two of the eight most significant counterparties for these activities, comprising $8 million, or 21%, of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Five of the eight most significant counterparties, comprising $28 million, or 78%, of this credit exposure, were not rated by external ratings agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount of this credit exposure, had credit quality less than investment grade, based on internal analysis. All eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were no gains or immaterial losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three months ended March 31, 2022 and 2021.

Changes in the fair value of FTRs resulting in pre-tax net gains of $1 million and $2 million recognized for the three months ended March 31, 2022 and 2021, respectively, which were reclassified as regulatory assets or liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement losses of $12 million and gains of $4 million were recognized for the three months ended March 31, 2022, and 2021, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three months ended March 31, 2022 and 2021.

Table of Contents

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	March 31, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 28	$ 28	$ (1)	$ 27	$ —	$ —	$ 27	$ 27	$ —	$ 27
Total current derivative assets	$ —	$ —	$ 28	$ 28	$ (1)	27	$ —	$ —	$ 27	$ 27	$ —	27
PPAs (b)						3						3
Current derivative instruments						$ 30						$ 30
Noncurrent derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 5	$ 5	$ —	$ 5	$ —	$ —	$ —	$ —	$ —	$ —
Total noncurrent derivative assets	$ —	$ —	$ 5	$ 5	$ —	5	$ —	$ —	$ —	$ —	$ —	—
PPAs (b)						5						6
Noncurrent derivative instruments						$ 10						$ 6
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 1	$ 1	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total current derivative liabilities	$ —	$ —	$ 1	$ 1	$ (1)	—	$ —	$ —	$ —	$ —	$ —	—
PPAs (b)						4						4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs (b)						$ 5						$ 6
Noncurrent derivative instruments						$ 5						$ 6

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at March 31, 2022 and Dec. 31, 2021. At March 31, 2022 and Dec. 31, 2021, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the three months ended March 31, 2022 and 2021:

	Three Months Ended March 31	
(Millions of Dollars)	**2022**	**2021**
Balance at Jan 1	$ 27	$ 7
Purchases	4	—
Settlements	(33)	(9)
Net transactions recorded during the period:		
Net gains (losses) recognized as regulatory assets and liabilities	34	14
Balance at March 31	$ 32	$ 12

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three months ended March 31, 2022 and 2021.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	March 31, 2022		Dec. 31, 2021	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt	$ 3,013	$ 3,057	$ 3,013	$ 3,454

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of March 31, 2022 and Dec. 31, 2021 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

Table of Contents

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended March 31	
	2022	2021
(Millions of Dollars)	Pension Benefits	
Service cost	$ 2	$ 2
Interest cost [(a)]	4	4
Expected return on plan assets [(a)]	(8)	(7)
Amortization of net loss [(a)]	3	4
Net periodic benefit cost	$ 1	$ 3
Effects of regulation	1	—
Net benefit cost recognized for financial reporting	$ 2	$ 3

(a) The components of net periodic cost other than the service cost component are included in the line item "Other income (expense), net" in the statements of income or capitalized on the balance sheets as a regulatory asset.

In January 2022, contributions of $50 million were made across four of Xcel Energy's pension plans, none of which was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2022.

9. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

Rate Matters and Other

SPS is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the financial statements.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C. Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. In February 2022, FERC issued an order rejecting SPS' request for hearing. SPS has appealed that order. That appeal has been combined with SPS' prior appeal.

Contract Termination — SPS and LP&L have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the Electric Reliability Council of Texas (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million, to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The settlement agreement is subject to approval by the PUCT and FERC.

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites

SPS is remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities from final resolution of these issues, however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Air

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes sulfur dioxide emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

Table of Contents

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether sulfur dioxide emission reductions beyond those required in the BART alternative rule referenced above are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule, but could impose additional requirements as part of a BART reconsideration or as part of the second planning period.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

	Three Months Ended March 31	
(Millions of Dollars)	**2022**	**2021**
Operating leases		
PPA capacity payments	$ 13	$ 13
Other operating leases [(a)]	2	1
Total operating lease expense [(b)]	$ 15	$ 14

(a) Includes immaterial short-term lease expense for 2022 and 2021.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in operating and maintenance expense and electric fuel and purchased power.

Commitments under operating leases as of March 31, 2022:

(Millions of Dollars)	PPA Operating Leases	Other Operating Leases	Total Operating Leases
Total minimum obligation	$ 532	$ 55	$ 587
Interest component of obligation	(115)	(16)	(131)
Present value of minimum obligation	$ 417	$ 39	456
Less current portion			(30)
Noncurrent operating and finance lease liabilities			$ 426

Variable Interest Entities

Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs at both March 31, 2022 and Dec. 31, 2021 with entities that have been determined to be variable interest entities. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

ITEM 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for SPS is omitted per conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in General Instruction H(2)(a) of Form 10-Q for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing earnings.

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that adjusts measures calculated and presented in accordance with GAAP.

SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. We use this non-GAAP financial measure to evaluate and provide details of SPS' core earnings and underlying performance.

We believe this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of SPS. For the three months ended March 31, 2022 and 2021, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

SPS' net income was approximately $52 million for the three months ended March 31, 2022 compared with approximately $58 million for the prior year. The decrease was primarily due to taxes (other than income taxes) and impacts associated with Winter Storm Uri, partially offset by favorable sales.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas and coal. However, these price fluctuations generally have minimal impact on earnings impact due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes.

Electric Revenues, Fuel and Purchased Power and Electric Margin

	Three Months Ended March 31	
(Millions of Dollars)	**2022**	**2021**
Electric revenues [(a)]	$ 477	$ 934
Electric fuel and purchased power [(a)]	(237)	(693)
Electric margin	$ 240	$ 241

(a) The decrease in revenue and electric fuel and purchased power is primarily due to Winter Storm Uri in 2021, resulting in higher fuel prices, as well as additional long-term energy sales/purchases market adjustments and SPP market transactions.

Table of Contents

Changes in electric margin:

(Millions of Dollars)	Three Months Ended March 31, 2022 vs. 2021
Regulatory rate outcomes (Texas and New Mexico)	$ 12
Sales and demand	13
PTCs flowed back to customers (offset by lower ETR)	(9)
Proprietary commodity trading, net of sharing [(a)]	(4)
Other (net)	(13)
Total decrease	$ (1)

(a) Includes $4 million of trading margin recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri.

Non-Fuel Operating Expense and Other Items

Taxes (other than income taxes) — Taxes (other than income taxes) increased $4 million for the first quarter, primarily driven by an increase in property tax expense.

Income Taxes — Income tax benefit increased $2 million for the first quarter. The increase was primarily driven by lower pretax earnings in 2022 and an increase in wind PTCs. Wind PTCs are largely credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

In April 2022, the Internal Revenue Service published inflation factors used to determine the PTC rate. As a result, the 2022 PTC rate on the sale of electricity produced from wind is 2.7 cents per kilowatt hour, compared to 2.5 cents for 2021.

See Note 6 to the financial statements for further information.

Public Utility Regulation and Other

The FERC and state and local regulatory commissions regulate SPS. SPS is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in utility rates through commission filings. Changes in operating costs can affect SPS' financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and demand side management efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2021 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending and Recently Concluded Regulatory Proceedings

2021 New Mexico Electric Rate Case — In January 2021, SPS filed an electric rate case with the NMPRC with a current requested base rate increase of $84 million.

In February 2022, the NMPRC approved an uncontested stipulation without modification, which reflected a $62 million rate increase, a change in the depreciation life of the Tolk coal plant to 2032, an equity ratio of 54.72% and a ROE of 9.35% for reconciliation statements and determining the revenue requirements for the Sagamore and Hale wind projects. New rates went into effect on Feb. 26, 2022.

2021 Texas Electric Rate Case — In 2021, SPS filed an electric rate case with the PUCT and its municipalities seeking an increase in base rates of approximately $140 million. The request was based on a ROE of 10.35%, an equity ratio of 54.60%, a rate base of approximately $3.3 billion and a historic test year based on the 12-months ended Dec. 31, 2020.

In January 2022, SPS and intervenors filed a blackbox settlement. Key terms include:

- Base rate increase of $89 million effective back to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for allowance for funds used during construction purposes only.
- Depreciation lives for Tolk moved up to 2034 and Harrington coal assets moved up to 2024.

In February 2022, the Administrative Law Judge issued an order approving interim rates effective March 1, 2022. A PUCT decision is expected in the second quarter of 2022.

Other

Supply Chain

SPS' ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Manufacturing processes have experienced disruptions related to scarcity of certain raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, labor shortages and the impact of international conflicts/issues. SPS continues to monitor the availability of materials and has sought to mitigate impacts by seeking alternative suppliers as necessary.

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, SPS incurred net natural gas, fuel and purchased energy costs of approximately $100 million (largely deferred as regulatory assets) in the first quarter.

SPS has electric fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, February cost increases were deferred for future recovery with recovery proposed over a period of up to two years to significantly mitigate the impact to customer bills. SPS currently has approval for recovery of Winter Storm Uri costs in New Mexico.

Regulatory Overview — In 2021, SPS filed to recover $88 million of Winter Storm Uri costs over 24 months, as part of the Texas fuel surcharge filing.

In January 2022, SPS and other parties filed a stipulation for interim rates. The filing covers all fuel under-collections occurring between January 2020 and August 2021, totaling $121 million. The settlement does not address the prudence of Winter Storm Uri costs nor the retention of $11 million related to market sales during the event. These items will be reviewed through the triennial Fuel Reconciliation proceeding and are subject to a final PUCT decision. Interim rates, designed to collect up to $110 million over a period of 30 months, began on Feb. 1, 2022.

Environmental

Affordable Clean Energy

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for greenhouse gas reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision would allow the EPA to proceed with alternate regulation of coal-fired power plants. However, the Court of Appeals decision has been appealed to the U.S Supreme Court, where the Court heard argument in February and is expected to rule by June on the nature and extent of the EPA's greenhouse gas regulatory authority. If any new rules require additional investment, SPS believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of March 31, 2022, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2021, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

Table of Contents

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation, dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	3.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Southwestern Public Service Company

4/28/2022	By:	/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer
		(Duly Authorized Officer and Principal Financial Officer)

2022 Form 10-Q

For the Quarterly Period Ended

June 30, 2022

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2022

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-03789

Southwestern Public Service Company

(Exact Name of Registrant as Specified in its Charter)

New Mexico	**75-0575400**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
790 South Buchanan Street Amarillo Texas	**79101**
(Address of Principal Executive Offices)	(Zip Code)

(303) 571-7511

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 28, 2022
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

TABLE OF CONTENTS

This Form 10-Q is filed by SPS, a New Mexico corporation. SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

Table of Contents

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries
Federal and State Regulatory Agencies	
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission
Other	
ACE	Affordable Clean Energy
BART	Best available retrofit technology
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
CPP	Clean Power Plan
ETR	Effective tax rate
FTR	Financial transmission right
GAAP	United States generally accepted accounting principles
IPP	Independent power producing entity
LP&L	Lubbock Power and Light
OATT	Open access transmission tariff
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
Measurements	
MW	Megawatts

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed in SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 and subsequent filings with the SEC, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including potential impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints, and their impact on capital expenditures and/or the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes and costs of potential regulatory penalties; and regulatory changes and/or limitations related to the use of natural gas as an energy source.

Table of Contents

PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended June 30		Six Months Ended June 30	
	2022	2021	2022	2021
Operating revenues	$ 658	$ 498	$ 1,135	$ 1,432
Operating expenses				
Electric fuel and purchased power	282	252	519	945
Operating and maintenance expenses	87	71	159	142
Demand side management expenses	6	4	11	8
Depreciation and amortization	132	78	210	156
Taxes (other than income taxes)	33	18	58	39
Total operating expenses	540	423	957	1,290
Operating income	118	75	178	142
Other income, net	1	—	1	1
Allowance for funds used during construction — equity	1	1	1	2
Interest charges and financing costs				
Interest charges — includes other financing costs of $1, $1, $2 and $2, respectively	46	29	75	59
Allowance for funds used during construction — debt	(1)	(1)	(1)	(1)
Total interest charges and financing costs	45	28	74	58
Income before income taxes	75	48	106	87
Income tax benefit	(18)	(20)	(39)	(39)
Net income	$ 93	$ 68	$ 145	$ 126

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Six Months Ended June 30	
	2022	2021
Operating activities		
Net income	$ 145	$ 126
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	211	158
Deferred income taxes	(19)	(39)
Allowance for equity funds used during construction	(1)	(2)
Provision for bad debts	4	3
Changes in operating assets and liabilities:		
Accounts receivable	(56)	(28)
Accrued unbilled revenues	(27)	(20)
Inventories	(15)	(16)
Prepayments and other	11	21
Accounts payable	35	6
Net regulatory assets and liabilities	(30)	(96)
Other current liabilities	8	1
Pension and other employee benefit obligations	1	(16)
Other, net	(2)	(2)
Net cash provided by operating activities	265	96
Investing activities		
Utility capital/construction expenditures	(260)	(334)
Investments in utility money pool arrangement	—	(83)
Repayments from utility money pool arrangement	—	83
Net cash used in investing activities	(260)	(334)
Financing activities		
Repayments of short-term borrowings, net	(137)	(250)
Proceeds from issuance of long-term debt, net	196	247
Borrowings under utility money pool arrangement	258	324
Repayments under utility money pool arrangement	(349)	(261)
Capital contributions from parent	209	304
Dividends paid to parent	(110)	(130)
Net cash provided by financing activities	67	234
Net change in cash, cash equivalents and restricted cash	72	(4)
Cash, cash equivalents and restricted cash at beginning of period	1	6
Cash, cash equivalents and restricted cash at end of period	$ 73	$ 2
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (71)	$ (54)
Cash received for income taxes, net	26	17
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 36	$ 39
Inventory transfers to property, plant and equipment	7	6
Allowance for equity funds used during construction	1	2

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	June 30, 2022	Dec. 31, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 73	$ 1
Accounts receivable, net	164	115
Accounts receivable from affiliates	12	9
Accrued unbilled revenues	152	125
Inventories	60	51
Regulatory assets	185	193
Derivative instruments	287	30
Prepaid taxes	3	3
Prepayments and other	61	21
Total current assets	997	548
Property, plant and equipment, net	7,938	7,838
Other assets		
Regulatory assets	392	380
Derivative instruments	5	6
Operating lease right-of-use assets	449	463
Other	30	27
Total other assets	876	876
Total assets	$ 9,811	$ 9,262
Liabilities and Equity		
Current liabilities		
Short-term debt	$ —	$ 137
Borrowings under utility money pool arrangement	—	91
Accounts payable	205	172
Accounts payable to affiliates	19	16
Regulatory liabilities	312	54
Taxes accrued	48	47
Accrued interest	31	30
Dividends payable to parent	59	58
Derivative instruments	4	4
Operating lease liabilities	30	30
Other	82	24
Total current liabilities	790	663
Deferred credits and other liabilities		
Deferred income taxes	691	702
Regulatory liabilities	716	709
Asset retirement obligations	119	116
Derivative instruments	4	6
Pension and employee benefit obligations	7	8
Operating lease liabilities	419	434
Other	8	8
Total deferred credits and other liabilities	1,964	1,983
Commitments and contingencies		
Capitalization		
Long-term debt	3,210	3,013
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at June 30, 2022 and Dec. 31, 2021, respectively	—	—
Additional paid in capital	3,301	3,091
Retained earnings	547	513
Accumulated other comprehensive loss	(1)	(1)
Total common stockholder's equity	3,847	3,603
Total liabilities and equity	$ 9,811	$ 9,262

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended June 30, 2022 and 2021						
Balance at March 31, 2021	100	$ —	$ 3,094	$ 515	$ (1)	$ 3,608
Net income				68		68
Dividends declared to parent				(79)		(79)
Balance at June 30, 2021	100	$ —	$ 3,094	$ 504	$ (1)	$ 3,597
Balance at March 31, 2022	100	$ —	$ 3,099	$ 512	$ (1)	$ 3,610
Net income				93		93
Dividends declared to parent				(58)		(58)
Contributions of capital by parent			202			202
Balance at June 30, 2022	100	$ —	$ 3,301	$ 547	$ (1)	$ 3,847

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Six Months Ended June 30, 2022 and 2021						
Balance at Dec. 31, 2020	100	$ —	$ 2,790	$ 509	$ (1)	$ 3,298
Net income				126		126
Dividends declared to parent				(131)		(131)
Contributions of capital by parent			304			304
Balance at June 30, 2021	100	$ —	$ 3,094	$ 504	$ (1)	$ 3,597
Balance at Dec. 31, 2021	100	$ —	$ 3,091	$ 513	$ (1)	$ 3,603
Net income				145		145
Dividends declared to parent				(111)		(111)
Contributions of capital by parent			210			210
Balance at June 30, 2022	100	$ —	$ 3,301	$ 547	$ (1)	$ 3,847

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with GAAP, the financial position of SPS as of June 30, 2022 and Dec. 31, 2021; the results of SPS' operations, including the components of net income and changes in stockholder's equity for the three and six months ended June 30, 2022 and 2021; and SPS' cash flows for the six months ended June 30, 2022 and 2021.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2022 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2021 balance sheet information has been derived from the audited 2021 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021.

Notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021, filed with the SEC on Feb. 23, 2022.

Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

As of June 30, 2022, there was no material impact from the recent adoption of new accounting pronouncements, nor expected material impact from recently issued accounting pronouncements yet to be adopted, on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	June 30, 2022	Dec. 31, 2021
Accounts receivable, net		
Accounts receivable	$ 176	$ 127
Less allowance for bad debts	(12)	(12)
Accounts receivable, net	$ 164	$ 115

(Millions of Dollars)	June 30, 2022	Dec. 31, 2021
Inventories		
Materials and supplies	$ 35	$ 29
Fuel	25	22
Total inventories	$ 60	$ 51

(Millions of Dollars)	June 30, 2022	Dec. 31, 2021
Property, plant and equipment, net		
Electric plant	$ 9,892	$ 9,639
Plant to be retired [(a)]	275	299
CWIP	164	171
Total property, plant and equipment	10,331	10,109
Less accumulated depreciation	(2,393)	(2,271)
Property, plant and equipment, net	$ 7,938	$ 7,838

(a) Amounts includes Tolk and conversion of Harrington to natural gas and are reported net of accumulated depreciation.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	—	91
Average amount outstanding	65	51
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	0.44 %	0.05 %
Weighted average interest rate at period end	N/A	0.05

Commercial Paper — Commercial paper outstanding for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	—	137
Average amount outstanding	150	63
Maximum amount outstanding	264	342
Weighted average interest rate, computed on a daily basis	0.97 %	0.21 %
Weighted average interest rate at period end	N/A	0.26

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. At both June 30, 2022 and Dec. 31, 2021, there were $2 million of letters of credit outstanding under the credit facility. Amounts approximate their fair value and are subject to fees.

Revolving Credit Facility — In order to issue its commercial paper, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper exceeding available capacity under this credit facility. The credit facility provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Table of Contents

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of June 30, 2022, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]		Drawn [(b)]		Available	
$	500	$	2	$	498

(a) Expires in June 2024.

(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of June 30, 2022 and Dec. 31, 2021.

Long-Term Borrowings

During the six months ended June 30, 2022, SPS issued $200 million of 5.15% first mortgage bonds due June 1, 2052.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consisted of the following:

	Three Months Ended June 30	
(Millions of Dollars)	**2022**	**2021**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 100	$ 85
Commercial and Industrial	264	201
Other	13	10
Total retail	377	296
Wholesale	109	118
Transmission	74	72
Other	3	2
Total revenue from contracts with customers	563	488
Alternative revenue and other	95	10
Total revenues	$ 658	$ 498

	Six Months Ended June 30	
(Millions of Dollars)	**2022**	**2021**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 197	$ 176
Commercial and Industrial	486	389
Other	21	19
Total retail	704	584
Wholesale	178	676
Transmission	146	143
Other	6	5
Total revenue from contracts with customers	1,034	1,408
Alternative revenue and other	101	24
Total revenues	$ 1,135	$ 1,432

6. Income Taxes

Reconciliation between the statutory rate and ETR:

	Six Months Ended June 30	
	2022	**2021**
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.5	2.6
Increases (decreases) in tax from:		
Wind PTCs [(a)]	(55.8)	(61.6)
Plant regulatory differences [(b)]	(4.0)	(5.0)
Amortization of excess nonplant deferred taxes	(1.1)	(1.2)
Other (net)	0.6	(0.6)
Effective income tax rate	(36.8)%	(44.8)%

(a) Wind PTCs are credited to customers (reduction to revenue) and do not materially impact net income.

(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred taxes are offset by corresponding revenue reductions.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated and may result in Level 3 classification.

Table of Contents

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The values of these instruments are derived from, and designed to offset, the costs of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of these instruments. FTRs are recognized at estimated fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3.

If costs of electric transmission congestion increase or decrease for a given path, the value of that particular instrument will likewise increase or decrease. Net congestion costs, including the impact of FTR settlements, are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of June 30, 2022, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings. As of June 30, 2022, SPS had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Amounts in Millions [(a)]	June 30, 2022	Dec. 31, 2021
Megawatt hours of electricity	18	8

(a) Amounts are not reflective of net positions in the underlying commodities.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts, prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

At June 30, 2022, two of the eight most significant counterparties for these activities, comprising $10 million, or 26%, of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Five of the eight most significant counterparties, comprising $29 million, or 74%, of this credit exposure, were not rated by external ratings agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount of this credit exposure, had credit quality less than investment grade, based on internal analysis. All eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were immaterial losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three and six months ended June 30, 2022, respectively. There were no gains or immaterial losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three and six months ended June 30, 2021, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains $92 million and gains of $93 million were recognized for the three and six months ended June 30, 2022, respectively, were reclassified as regulatory assets or liabilities. Changes in the fair value of FTRs resulting in pre-tax net gains of $8 million and $10 million recognized for the three and six months ended June 30, 2021, respectively, were reclassified as regulatory assets or liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement losses of $24 million and losses of $34 million were recognized for the three and six months ended June 30, 2022, respectively, and were recorded to electric fuel and purchased power. FTR settlement losses of $4 million and gains of $11 million were recognized for the three and six months ended June 30, 2021, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate. All FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.

SPS had immaterial derivative instruments designated as fair value hedges during the three and six months ended June 30, 2022 and 2021.

Table of Contents

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	June 30, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity (b)	$ —	$ —	$ 284	$ 284	$ —	$ 284	$ —	$ —	$ 27	$ 27	$ —	$ 27
Total current derivative assets	$ —	$ —	$ 284	$ 284	$ —	284	$ —	$ —	$ 27	$ 27	$ —	27
PPAs (c)						3						3
Current derivative instruments						$ 287						$ 30
Noncurrent derivative assets												
PPAs (c)						$ 5						$ 6
Noncurrent derivative instruments						$ 5						$ 6
Current derivative liabilities												
PPAs (c)						$ 4						$ 4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs (c)						$ 4						$ 6
Noncurrent derivative instruments						$ 4						$ 6

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at June 30, 2022 and Dec. 31, 2021. At June 30, 2022 and Dec. 31, 2021, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) Amounts relate to FTR instruments administered by SPP (annual auctions occurring in the second quarter). These instruments are utilized/intended to offset the impacts of transmission system congestion. Higher congestion costs have led to an increase in the fair value of FTRs. Due to regulatory recovery, changes in fair value are deferred as a regulatory asset or liability and do not have a material impact on net income.

(c) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the three and six months ended June 30, 2022 and 2021:

	Three Months Ended June 30	
(Millions of Dollars)	2022	2021
Balance at April 1	$ 32	$ 12
Purchases/Issuances (a)	232	9
Settlements (a)	(85)	(12)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities (a)	105	32
Balance at June 30	$ 284	$ 41

	Six Months Ended June 30	
(Millions of Dollars)	2022	2021
Balance at Jan. 1	$ 27	$ 7
Purchases/Issuances (a)	237	9
Settlements (a)	(94)	(21)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities (a)	114	46
Balance at June 30	$ 284	$ 41

(a) Relates primarily to FTR instruments administered by SPP (annual auctions occurring in the second quarter). These instruments are utilized/intended to offset the impacts of transmission system congestion. Higher congestion costs have led to an increase in the fair value of FTRs. Due to regulatory recovery, changes in fair value are deferred as a regulatory asset or liability and do not have a material impact on net income.

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and six months ended June 30, 2022 and 2021.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	June 30, 2022		Dec. 31, 2021	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 3,210	$ 2,890	$ 3,013	$ 3,454

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of June 30, 2022 and Dec. 31, 2021 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

Table of Contents

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2022	2021	2022	2021
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 3	$ 3	$ —	$ —
Interest cost [(a)]	4	4	1	—
Expected return on plan assets [(a)]	(7)	(8)	(1)	(1)
Amortization of net loss [(a)]	2	3	—	—
Net periodic benefit cost	$ 2	$ 2	$ —	$ (1)
Effects of regulation	(1)	1	—	—
Net benefit cost recognized for financial reporting	$ 1	$ 3	$ —	$ (1)

	Six Months Ended June 30			
	2022	2021	2022	2021
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 5	$ 5	$ —	$ —
Interest cost [(a)]	8	8	1	—
Expected return on plan assets [(a)]	(15)	(15)	(1)	(1)
Amortization of net loss (gain) [(a)]	5	7	—	—
Net periodic benefit cost	$ 3	$ 5	$ —	$ (1)
Effects of regulation	—	1	—	—
Net benefit cost recognized for financial reporting	$ 3	$ 6	$ —	$ (1)

(a) The components of net periodic cost other than the service cost component are included in the line item "Other income, net" in the statements of income or capitalized on the balance sheets as a regulatory asset.

In January 2022, contributions of $50 million were made across four of Xcel Energy's pension plans, none of which was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2022.

9. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

Other Litigation — In 2019, SPS and Xcel Energy Services, Inc. were served with a lawsuit related to a traffic accident that resulted in two fatalities in New Mexico. An estimate of a probable loss contingency of approximately $50 million was recorded as of June 30, 2022 within Other current liabilities. In July 2022, a confidential settlement was reached. No impact to earnings has or is expected to occur, as the amounts are expected to be reimbursed by SPS' insurers. An offsetting asset has been recorded to reflect the reimbursement within Prepayments and other current assets.

Rate Matters and Other

SPS is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the financial statements.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C. Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. In February 2022, FERC issued an order rejecting SPS' request for hearing. SPS has appealed that order. That appeal has been combined with SPS' prior appeal.

Contract Termination — SPS and LP&L have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the Electric Reliability Council of Texas (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million, to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The agreement is subject to approval by the PUCT and FERC.

Table of Contents

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites

SPS is remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities from final resolution of these issues, however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Air

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes sulfur dioxide emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether sulfur dioxide emission reductions beyond those required in the BART alternative rule referenced above are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule, but could impose additional requirements as part of a BART reconsideration or as part of the second planning period.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

	Three Months Ended June 30	
(Millions of Dollars)	**2022**	**2021**
Operating leases		
PPA capacity payments	$ 13	$ 13
Other operating leases [(a)]	1	1
Total operating lease expense [(b)]	$ 14	$ 14

(a) Includes immaterial short-term lease expense for 2022 and 2021.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in operating and maintenance expense and electric fuel and purchased power.

	Six Months Ended June 30	
(Millions of Dollars)	**2022**	**2021**
Operating leases		
PPA capacity payments	$ 26	$ 26
Other operating leases [(a)]	3	2
Total operating lease expense [(b)]	$ 29	$ 28

(a) Includes immaterial short-term lease expense for 2022 and 2021.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in operating and maintenance expense and electric fuel and purchased power.

Commitments under operating leases as of June 30, 2022:

(Millions of Dollars)	PPA Operating Leases	Other Operating Leases	Total Operating Leases
Total minimum obligation	$ 520	$ 55	$ 575
Interest component of obligation	(111)	(15)	(126)
Present value of minimum obligation	$ 409	$ 40	449
Less current portion			(30)
Noncurrent operating lease liabilities			$ 419

Variable Interest Entities

Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs at both June 30, 2022 and Dec. 31, 2021 with entities that have been determined to be variable interest entities. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

ITEM 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for SPS is omitted per conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in General Instruction H(2)(a) of Form 10-Q for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing earnings.

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that adjusts measures calculated and presented in accordance with GAAP.

SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. We use this non-GAAP financial measure to evaluate and provide details of SPS' core earnings and underlying performance.

We believe this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of SPS. For the three and six months ended June 30, 2022 and 2021, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Table of Contents

Results of Operations

SPS' net income was approximately $145 million for the six months ended June 30, 2022 compared with approximately $126 million for the prior year. The increase reflects the impact of regulatory outcomes, strong sales growth and favorable weather.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas and coal. However, these price fluctuations generally have minimal impact on earnings impact due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes.

Electric revenues, fuel and purchased power and electric margin and explanation of the changes are listed as follows:

(Millions of Dollars)	Six Months Ended June 30 2022	2021
Electric revenues [(a)]	$ 1,135	$ 1,432
Electric fuel and purchased power [(a)]	(519)	(945)
Electric margin	$ 616	$ 487

(a) The decrease in revenue and electric fuel and purchased power is primarily due to Winter Storm Uri in 2021 (higher fuel prices, as well as additional long-term energy sales/purchases market adjustments and SPP market transactions).

(Millions of Dollars)	Six Months Ended June 30, 2022 vs. 2021
Revenue recognition for the Texas rate case surcharge [(a)]	$ 85
Regulatory rate outcomes (Texas and New Mexico)	50
Sales and demand	33
Estimated impact of weather	9
PTCs flowed back to customers (offset by lower ETR)	(19)
Proprietary commodity trading, net of sharing [(b)]	(5)
Other (net)	(24)
Total increase	$ 129

(a) Recognition of revenue from the Texas rate case outcome is largely offset by recognition of previously deferred costs, see Public Utility Regulation and Other for additional information.

(b) Includes $4 million of trading margin recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri.

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses increased $17 million year-to-date. The increase is primarily due to recognition of previously deferred amounts related to the Texas Electric Rate Case.

Depreciation and Amortization — Depreciation and amortization increased $54 million year-to-date. The increase is primarily due to the recognition of previously deferred amounts related to the Texas Electric Rate Case and the implementation of new depreciation rates in Texas.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $19 million year-to-date, largely due to an increase in property taxes and the recognition of previously deferred amounts related to the Texas Electric Rate Case.

Interest Charges — Interest expenses increased $16 million year-to-date, largely due to the recognition of previously deferred amounts related to the Texas Electric Rate Case and increased long-term debt levels to fund capital investments and deferred balances related to Winter Storm Uri.

Public Utility Regulation and Other

The FERC and state and local regulatory commissions regulate SPS. SPS is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in utility rates through commission filings. Changes in operating costs can affect SPS' financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and demand side management efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2021 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending and Recently Concluded Regulatory Proceedings

2021 Texas Electric Rate Case — In 2021, SPS filed an electric rate case with the PUCT and its municipalities seeking an increase in base rates of approximately $140 million. In May 2022, the PUCT approved a settlement between SPS and intervening parties, which reflects the following terms:

- Base rate increase of $89 million effective retroactively to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for AFUDC purposes only.
- Depreciation lives for Tolk accelerated to 2034 and Harrington coal assets accelerated to 2024.

In July 2022, SPS filed to surcharge the final under-recovered amount, estimated to be approximately $85 million, substantially offset by the recognition of previously deferred costs. The impact of the retroactive amounts is as follows:

(Millions of Dollars)	Six Months Ended June 30, 2022
Revenue surcharge accrual	$ 85
Depreciation and amortization	(43)
O&M expenses	(16)
Interest expense	(12)
Taxes other than income taxes	(10)
Fuel and purchased power	(2)

Other

Supply Chain

SPS' ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Manufacturing processes have experienced disruptions related to scarcity of certain raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, labor shortages and the impact of international conflicts/issues. SPS continues to monitor the availability of materials and has sought to mitigate impacts by seeking alternative suppliers as necessary.

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, SPS incurred net natural gas, fuel and purchased energy costs of approximately $100 million (largely deferred as regulatory assets).

SPS has electric fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, February cost increases were deferred for future recovery proposed over a period of up to two years to significantly mitigate the impact to customer bills. SPS currently has approval for recovery of Winter Storm Uri costs in New Mexico.

Texas Regulatory Overview — In 2021, SPS filed to recover $88 million of Winter Storm Uri costs over 24 months, as part of the Texas fuel surcharge filing, with total under-recovered costs of $121 million.

In April 2022, interim rates designed to recover $121 million over 30 months were implemented. The interim rate recovery does not address the prudence of costs nor the retention of approximately $10 million related to market sales during the event. These items will be reviewed through the triennial Fuel Reconciliation proceeding and are subject to a final PUCT decision.

In July 2022, the intervenors filed recommendations in the Fuel Reconciliation proceeding. The Texas Industrial Energy Consumers and PUCT staff recommended disallowances of approximately $10 million (off-system sales margins). The Office of Public Utility Counsel recommended disallowances of approximately $15 million (off-system sales margins and adjustment to energy loss factors). The Alliance of Xcel Municipalities recommended disallowances of approximately $100 million (natural gas storage, contracted capability and off-system sales margins).

A hearing is scheduled to begin in August and a recommendation from the ALJ is expected in the fourth quarter of 2022.

Environmental

Affordable Clean Energy

In July 2019, the EPA adopted the ACE rule, which requires states to develop plans by 2022 for greenhouse gas reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the ACE rule. That decision essentially held that EPA's previous economy-wide regulatory approach taken in the 2015 CPP was consistent with the Clean Air Act. If upheld, that decision would have allowed the EPA to proceed with alternate regulation of coal-fired power plants consistent with the CPP approach. However, the Court of Appeals decision was appealed to the U.S Supreme Court. In a June 30, 2022, ruling, the Supreme Court held that a CPP economy-wide approach is not consistent with the Clean Air Act. Thus, if EPA is to proceed with new rules, they must be consistent with this ruling and be more similar to the ACE rule "inside the fenceline" approach. If any new rules require additional investment, SPS believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of June 30, 2022, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting.

Table of Contents

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2021, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation, dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	3.02
4.01*	Supplemental Indenture No. 9 dated as of May 1, 2022 between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as trustee, creating $200 million principal amount of 5.15% First Mortgage Bonds, Series No. 9 due 2052	SPS Form 8-K dated May 31, 2022	4.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Southwestern Public Service Company

7/28/2022	By:	/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer
		(Duly Authorized Officer and Principal Financial Officer)

2022 Form 10-Q

For the Quarterly Period Ended

September 30, 2022

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended Sept. 30, 2022

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-03789

Southwestern Public Service Company
(Exact Name of Registrant as Specified in its Charter)

New Mexico	**75-0575400**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
790 South Buchanan Street Amarillo Texas	**79101**
(Address of Principal Executive Offices)	(Zip Code)

(303) 571-7511
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 27, 2022
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

TABLE OF CONTENTS

This Form 10-Q is filed by SPS, a New Mexico corporation. SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

Table of Contents

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Other

ACE	Affordable Clean Energy
AMT	Alternative minimum tax
CEO	Chief executive officer
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFO	Chief financial officer
COVID-19	Novel coronavirus
ETR	Effective tax rate
FTR	Financial transmission right
GAAP	United States generally accepted accounting principles
IPP	Independent power producing entity
IRA	Inflation Reduction Act
ITC	Investment tax credit
LP&L	Lubbock Power and Light
NOx	Nitrogen Oxides
OATT	Open access transmission tariff
PFAS	Per- and PolyFluoroAlkyl Substances
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.

Measurements

MW	Megawatts

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed in SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 and subsequent filings with the SEC, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including potential workforce impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including recessionary conditions, inflation rates, monetary fluctuations, supply chain constraints, and their impact on capital expenditures and/or the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes and costs of potential regulatory penalties; regulatory changes and/or limitations related to the use of natural gas as an energy source; and our ability to execute on our strategies or achieve expectations related to environmental, social and governance matters, including as a result of evolving legal, regulatory and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets.

Table of Contents

PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2022	2021	2022	2021
Operating revenues	$ 741	$ 575	$ 1,876	$ 2,007
Operating expenses				
Electric fuel and purchased power	362	250	881	1,195
Operating and maintenance expenses	79	66	238	208
Demand side management expenses	7	5	18	13
Depreciation and amortization	89	71	299	227
Taxes (other than income taxes)	26	20	84	59
Total operating expenses	563	412	1,520	1,702
Operating income	178	163	356	305
Other (expense) income, net	(3)	—	(2)	1
Allowance for funds used during construction — equity	1	1	2	3
Interest charges and financing costs				
Interest charges — includes other financing costs of $1, $1, $3 and $3, respectively	33	28	108	87
Allowance for funds used during construction — debt	—	—	(1)	(1)
Total interest charges and financing costs	33	28	107	86
Income before income taxes	143	136	249	223
Income tax expense (benefit)	5	2	(34)	(37)
Net income	$ 138	$ 134	$ 283	$ 260

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Nine Months Ended Sept. 30	
	2022	2021
Operating activities		
Net income	$ 283	$ 260
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	302	229
Deferred income taxes	21	(31)
Allowance for equity funds used during construction	(2)	(3)
Provision for bad debts	6	6
Changes in operating assets and liabilities:		
Accounts receivable	(69)	(66)
Accrued unbilled revenues	(28)	(20)
Inventories	(14)	(14)
Prepayments and other	(5)	21
Accounts payable	49	6
Net regulatory assets and liabilities	(73)	(113)
Other current liabilities	30	19
Pension and other employee benefit obligations	1	(16)
Other, net	(2)	(2)
Net cash provided by operating activities	499	276
Investing activities		
Utility capital/construction expenditures	(405)	(446)
Investments in utility money pool arrangement	(133)	(83)
Repayments from utility money pool arrangement	113	83
Net cash used in investing activities	(425)	(446)
Financing activities		
Repayments of short-term borrowings, net	(137)	(232)
Proceeds from issuance of long-term debt, net	196	247
Borrowings under utility money pool arrangement	262	539
Repayments under utility money pool arrangement	(353)	(439)
Capital contributions from parent	210	304
Dividends paid to parent	(250)	(254)
Net cash (used in) provided by financing activities	(72)	165
Net change in cash, cash equivalents and restricted cash	2	(5)
Cash, cash equivalents and restricted cash at beginning of period	1	6
Cash, cash equivalents and restricted cash at end of period	$ 3	$ 1
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (94)	$ (75)
Cash received for income taxes, net	45	19
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 40	$ 39
Inventory transfers to property, plant and equipment	8	6
Allowance for equity funds used during construction	2	3

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	Sept. 30, 2022	Dec. 31, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 3	$ 1
Accounts receivable, net	171	115
Accounts receivable from affiliates	15	9
Investments in money pool arrangements	20	—
Accrued unbilled revenues	153	125
Inventories	58	51
Regulatory assets	274	193
Derivative instruments	237	30
Prepaid taxes	13	3
Prepayments and other	67	21
Total current assets	1,011	548
Property, plant and equipment, net	8,006	7,838
Other assets		
Regulatory assets	352	380
Derivative instruments	4	6
Operating lease right-of-use assets	441	463
Other	31	27
Total other assets	828	876
Total assets	$ 9,845	$ 9,262
Liabilities and Equity		
Current liabilities		
Short-term debt	$ —	$ 137
Borrowings under utility money pool arrangement	—	91
Accounts payable	216	172
Accounts payable to affiliates	24	16
Regulatory liabilities	262	54
Taxes accrued	61	47
Accrued interest	41	30
Dividends payable to parent	69	58
Derivative instruments	4	4
Operating lease liabilities	31	30
Other	81	24
Total current liabilities	789	663
Deferred credits and other liabilities		
Deferred income taxes	738	702
Regulatory liabilities	723	709
Asset retirement obligations	120	116
Derivative instruments	3	6
Pension and employee benefit obligations	7	8
Operating lease liabilities	411	434
Other	9	8
Total deferred credits and other liabilities	2,011	1,983
Commitments and contingencies		
Capitalization		
Long-term debt	3,210	3,013
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at September 30, 2022 and Dec. 31, 2021, respectively	—	—
Additional paid in capital	3,301	3,091
Retained earnings	535	513
Accumulated other comprehensive loss	(1)	(1)
Total common stockholder's equity	3,835	3,603
Total liabilities and equity	$ 9,845	$ 9,262

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended Sept. 30, 2022 and 2021						
Balance at June 30, 2021	100	$ —	$ 3,094	$ 504	$ (1)	$ 3,597
Net income				134		134
Dividends declared to parent				(122)		(122)
Contributions of capital by parent			(3)			(3)
Balance at Sept. 30, 2021	100	$ —	$ 3,091	$ 516	$ (1)	$ 3,606
Balance at June 30, 2022	100	$ —	$ 3,301	$ 547	$ (1)	$ 3,847
Net income				138		138
Dividends declared to parent				(150)		(150)
Balance at Sept. 30, 2022	100	$ —	$ 3,301	$ 535	$ (1)	$ 3,835

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Nine Months Ended Sept. 30, 2022 and 2021						
Balance at Dec. 31, 2020	100	$ —	$ 2,790	$ 509	$ (1)	$ 3,298
Net income				260		260
Dividends declared to parent				(253)		(253)
Contributions of capital by parent			301			301
Balance at Sept. 30, 2021	100	$ —	$ 3,091	$ 516	$ (1)	$ 3,606
Balance at Dec. 31, 2021	100	$ —	$ 3,091	$ 513	$ (1)	$ 3,603
Net income				283		283
Dividends declared to parent				(261)		(261)
Contributions of capital by parent			210			210
Balance at Sept. 30, 2022	100	$ —	$ 3,301	$ 535	$ (1)	$ 3,835

See Notes to Financial Statements

Table of Contents

SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with GAAP, the financial position of SPS as of Sept. 30, 2022 and Dec. 31, 2021; the results of SPS' operations, including the components of net income and changes in stockholder's equity for the three and nine months ended Sept. 30, 2022 and 2021; and SPS' cash flows for the nine months ended Sept. 30, 2022 and 2021.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2022 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2021 balance sheet information has been derived from the audited 2021 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021.

Notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021, filed with the SEC on Feb. 23, 2022.

Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2021 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

As of Sept. 30, 2022, there was no material impact from the recent adoption of new accounting pronouncements, nor expected material impact from recently issued accounting pronouncements yet to be adopted, on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	Sept. 30, 2022	Dec. 31, 2021
Accounts receivable, net		
Accounts receivable	$ 184	$ 127
Less allowance for bad debts	(13)	(12)
Accounts receivable, net	$ 171	$ 115

(Millions of Dollars)	Sept. 30, 2022	Dec. 31, 2021
Inventories		
Materials and supplies	$ 38	$ 29
Fuel	20	22
Total inventories	$ 58	$ 51

(Millions of Dollars)	Sept. 30, 2022	Dec. 31, 2021
Property, plant and equipment, net		
Electric plant	$ 9,947	$ 9,639
Plant to be retired [(a)]	270	299
CWIP	230	171
Total property, plant and equipment	10,447	10,109
Less accumulated depreciation	(2,441)	(2,271)
Property, plant and equipment, net	$ 8,006	$ 7,838

(a) Amounts include Tolk and conversion of Harrington to natural gas and are reported net of accumulated depreciation.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	—	91
Average amount outstanding	—	51
Maximum amount outstanding	4	100
Weighted average interest rate, computed on a daily basis	2.27 %	0.05 %
Weighted average interest rate at period end	N/A	0.05

Commercial Paper — Commercial paper outstanding for SPS:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	—	137
Average amount outstanding	—	63
Maximum amount outstanding	—	342
Weighted average interest rate, computed on a daily basis	N/A	0.21 %
Weighted average interest rate at period end	N/A	0.26

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. At both Sept. 30, 2022 and Dec. 31, 2021, there were $2 million of letters of credit outstanding under the credit facility. Amounts approximate their fair value and are subject to fees.

Revolving Credit Facility — In order to issue its commercial paper, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper exceeding available capacity under this credit facility. The credit facility provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Table of Contents

In September 2022, SPS entered into an amended five-year credit agreement with a syndicate of banks, with substantially the same terms and conditions as the prior credit agreements. The maturity was extended from June 2024 to September 2027.

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of Sept. 30, 2022, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 2	$ 498

(a) Expires in September 2027.
(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of Sept. 30, 2022 and Dec. 31, 2021.

Long-Term Borrowings

During the nine months ended Sept. 30, 2022, SPS issued $200 million of 5.15% first mortgage bonds due June 1, 2052.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consisted of the following:

	Three Months Ended Sept. 30	
(Millions of Dollars)	**2022**	**2021**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 159	$ 126
Commercial and Industrial	325	241
Other	17	11
Total retail	501	378
Wholesale	149	109
Transmission	80	75
Other	—	2
Total revenue from contracts with customers	730	564
Alternative revenue and other	11	11
Total revenues	$ 741	$ 575

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2022**	**2021**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 356	$ 302
Commercial and Industrial	811	631
Other	38	30
Total retail	1,205	963
Wholesale	327	785
Transmission	226	218
Other	6	6
Total revenue from contracts with customers	1,764	1,972
Alternative revenue and other	112	35
Total revenues	$ 1,876	$ 2,007

6. Income Taxes

Reconciliation between the statutory rate and ETR:

	Nine Months Ended Sept. 30	
	2022	**2021**
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.3	2.5
Decreases:		
Wind PTCs [(a)]	(31.8)	(32.9)
Plant regulatory differences [(b)]	(3.7)	(4.9)
Amortization of excess nonplant deferred taxes	(0.9)	(1.1)
Other (net)	(0.6)	(1.2)
Effective income tax rate	(13.7)%	(16.6)%

(a) Wind PTCs are credited to customers (reduction to revenue) and do not materially impact net income.
(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred taxes are offset by corresponding revenue reductions.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated and may result in Level 3 classification.

Table of Contents

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The values of these instruments are derived from, and designed to offset, the costs of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of these instruments. FTRs are recognized at fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3.

If costs of electric transmission congestion increase or decrease for a given path, the value of that particular instrument will likewise increase or decrease. Net congestion costs, including the impact of FTR settlements, are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of Sept. 30, 2022, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings. As of Sept. 30, 2022, SPS had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Amounts in Millions [(a)]	Sept. 30, 2022	Dec. 31, 2021
Megawatt hours of electricity	12	8

(a) Amounts are not reflective of net positions in the underlying commodities.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts, prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

At Sept. 30, 2022, two of the eight most significant counterparties for these activities, comprising $9 million, or 27%, of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Five of the eight most significant counterparties, comprising $25 million, or 72%, of this credit exposure, were not rated by external ratings agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount of this credit exposure, had credit quality less than investment grade, based on internal analysis. All eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income — Changes in the fair value of FTRs resulting in pre-tax net losses of $13 million and gains of $80 million for the three and nine months ended Sept. 30, 2022, respectively, were recognized as regulatory assets or liabilities. Changes in the fair value of FTRs resulting in pre-tax net gains of $5 million and $15 million for the three and nine months ended Sept. 30, 2021, respectively, were recognized as regulatory assets or liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement losses of $8 million and gains of $26 million for the three and nine months ended Sept. 30, 2022, respectively, were recorded to electric fuel and purchased power. FTR settlement losses of $4 million and gains of $13 million for the three and nine months ended Sept. 30, 2021, respectively, were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate.

All FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.

SPS had immaterial derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2022 and 2021.

Table of Contents

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	Sept. 30, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity (b)	$ —	$ —	$ 234	$ 234	$ —	$ 234	$ —	$ —	$ 27	$ 27	$ —	$ 27
Total current derivative assets	$ —	$ —	$ 234	$ 234	$ —	234	$ —	$ —	$ 27	$ 27	$ —	27
PPAs (c)						3						3
Current derivative instruments						$ 237						$ 30
Noncurrent derivative assets												
PPAs (c)						$ 4						$ 6
Noncurrent derivative instruments						$ 4						$ 6
Current derivative liabilities												
PPAs (c)						$ 4						$ 4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs (c)						$ 3						$ 6
Noncurrent derivative instruments						$ 3						$ 6

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement. At Sept. 30, 2022 and Dec. 31, 2021, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. Counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) Amounts relate to FTR instruments administered by SPP (annual auctions occurring in the second quarter). These instruments are utilized/intended to offset the impacts of transmission system congestion. Higher congestion costs have led to an increase in the fair value of FTRs. Due to regulatory recovery, fair values for FTRs are offset/deferred as a regulatory asset or liability and do not have a material impact on net income.

(c) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2022 and 2021:

	Three Months Ended Sept. 30	
(Millions of Dollars)	2022	2021
Balance at July 1	$ 284	$ 41
Purchases/Issuances (a)	4	2
Settlements (a)	(22)	(18)
Net transactions recorded during the period:		
Net (losses) gains recognized as regulatory assets and liabilities (a)	(32)	12
Balance at Sept. 30	$ 234	$ 37

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2022	2021
Balance at Jan. 1	$ 27	$ 7
Purchases/Issuances (a)	241	11
Settlements (a)	(116)	(39)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities (a)	82	58
Balance at Sept. 30	$ 234	$ 37

(a) Relates primarily to FTR instruments administered by SPP (annual auctions occurring in the second quarter). These instruments are utilized/intended to offset the impacts of transmission system congestion. Higher congestion costs have led to an increase in the fair value of FTRs. Due to regulatory recovery, changes in fair value are deferred as a regulatory asset or liability and do not have a material impact on net income.

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2022 and 2021.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	Sept. 30, 2022		Dec. 31, 2021	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 3,210	$ 2,656	$ 3,013	$ 3,454

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Sept. 30, 2022 and Dec. 31, 2021 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

Table of Contents

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2022	2021	2022	2021
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 2	$ 3	$ —	$ —
Interest cost [(a)]	4	3	—	—
Expected return on plan assets [(a)]	(8)	(7)	—	—
Amortization of net loss (gain) [(a)]	3	4	(1)	—
Settlement charge [(b)]	2	—	—	—
Net periodic benefit cost	$ 3	$ 3	$ (1)	$ —
Effects of regulation	(1)	(1)	—	—
Net benefit cost recognized for financial reporting	$ 2	$ 2	$ (1)	$ —

	Nine Months Ended Sept. 30			
	2022	2021	2022	2021
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 7	$ 8	$ —	$ —
Interest cost [(a)]	12	11	1	—
Expected return on plan assets [(a)]	(23)	(22)	(1)	(1)
Amortization of net loss (gain) [(a)]	8	11	(1)	—
Settlement charge [(b)]	2	—	—	—
Net periodic benefit cost	$ 6	$ 8	$ (1)	$ (1)
Effects of regulation	(1)	—	—	—
Net benefit cost recognized for financial reporting	$ 5	$ 8	$ (1)	$ (1)

(a) The components of net periodic cost other than the service cost component are included in the line item "Other income, net" in the statements of income or capitalized on the balance sheets as a regulatory asset.

(b) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In the third quarter as a result of lump-sum distributions during the 2022 plan year, SPS recorded a pension settlement charge of $2 million, the majority of which was not recognized in earnings due to the effects of regulation.

In January 2022, contributions of $50 million were made across four of Xcel Energy's pension plans, none of which was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2022.

9. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

Other Litigation — In 2019, SPS and Xcel Energy Services, Inc. were served with a lawsuit related to a traffic accident that resulted in two fatalities in New Mexico. A loss contingency of approximately $50 million was recorded as of Sept. 30, 2022 within Other current liabilities. In July 2022, a confidential settlement was reached. No impact to earnings has or is expected to occur, as the amounts are expected to be reimbursed by SPS' insurers. An offsetting asset has been recorded to reflect the reimbursement within Prepayments and other current assets.

Rate Matters and Other

SPS is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the financial statements.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C. Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. In February 2022, FERC issued an order rejecting SPS' request for hearing. SPS has appealed that order. That appeal has been combined with SPS' prior appeal.

Table of Contents

Contract Termination — SPS and LP&L have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the Electric Reliability Council of Texas (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million, to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The agreement is subject to approval by the PUCT and FERC. Approval steps are in process, but approval timing from the PUCT is uncertain.

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites

SPS is remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities from final resolution of these issues, however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Air

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes sulfur dioxide emission limitations which would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. SPS appealed the EPA's decision and obtained a stay of the final rule.

In 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration (leaving the stay in effect). In a future rulemaking, the EPA may address whether further sulfur dioxide emission reductions are necessary.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

	Three Months Ended Sept. 30	
(Millions of Dollars)	**2022**	**2021**
Operating leases		
PPA capacity payments	$ 13	$ 13
Other operating leases [(a)]	1	—
Total operating lease expense [(b)]	$ 14	$ 13

(a) Includes immaterial short-term lease expense for 2022 and 2021.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in operating and maintenance expense and electric fuel and purchased power.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2022**	**2021**
Operating leases		
PPA capacity payments	$ 39	$ 40
Other operating leases [(a)]	4	2
Total operating lease expense [(b)]	$ 43	$ 42

(a) Includes short-term lease expense of $1 million for 2022 and 2021, respectively.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in operating and maintenance expense and electric fuel and purchased power.

Commitments under operating leases as of Sept. 30, 2022:

(Millions of Dollars)	**PPA Operating Leases**	**Other Operating Leases**	**Total Operating Leases**
Total minimum obligation	$ 508	$ 54	$ 562
Interest component of obligation	(106)	(14)	(120)
Present value of minimum obligation	$ 402	$ 40	442
Less current portion			(31)
Noncurrent operating lease liabilities			$ 411

Variable Interest Entities

Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs at both Sept. 30, 2022 and Dec. 31, 2021 with entities that have been determined to be variable interest entities. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

ITEM 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for SPS is omitted per conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in General Instruction H(2)(a) of Form 10-Q for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing earnings.

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that adjusts measures calculated and presented in accordance with GAAP.

SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. We use this non-GAAP financial measure to evaluate and provide details of SPS' core earnings and underlying performance.

We believe this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of SPS. For the three and nine months ended Sept. 30, 2022 and 2021, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Table of Contents

Results of Operations

SPS' net income was approximately $283 million for the nine months ended Sept. 30, 2022 compared with approximately $260 million for the prior year. The increase largely reflects regulatory rate outcomes, strong sales growth and favorable weather, partially offset by higher depreciation, O&M expenses and interest charges.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas and coal. However, these price fluctuations generally have minimal impact on earnings impact due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes.

Electric revenues, fuel and purchased power and electric margin and explanation of the changes are listed as follows:

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2022**	**2021**
Electric revenues [(a)]	$ 1,876	$ 2,007
Electric fuel and purchased power [(a)]	(881)	(1,195)
Electric margin	$ 995	$ 812

(a) The decrease in revenue and electric fuel and purchased power is primarily due to Winter Storm Uri in 2021 (higher fuel prices, as well as additional long-term energy sales/purchases market adjustments and SPP market transactions).

(Millions of Dollars)	**Nine Months Ended Sept. 30, 2022 vs. 2021**
Regulatory rate outcomes (Texas and New Mexico)	$ 100
Revenue recognition for the Texas rate case surcharge [(a)]	85
Sales and demand	41
Estimated impact of weather	18
Proprietary commodity trading, net of sharing [(b)]	(5)
PTCs flowed back to customers (offset by lower ETR)	(25)
Other (net)	(31)
Total increase	$ 183

(a) Recognition of revenue from the Texas rate case outcome is largely offset by recognition of previously deferred costs, see Public Utility Regulation and Other for additional information.

(b) Includes $4 million of trading margin recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri.

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses increased $30 million year-to-date. The increase is primarily due to recognition of previously deferred amounts related to the Texas Electric Rate Case, additional investments in technology and customer programs and inflation. These increases were partially offset by a reduction in employee benefits costs.

Depreciation and Amortization — Depreciation and amortization increased $72 million year-to-date. The increase is primarily due to the recognition of previously deferred amounts related to the Texas Electric Rate Case, normal system expansion and the implementation of new depreciation rates in Texas and New Mexico.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $25 million year-to-date, largely due to an increase in property taxes and the recognition of previously deferred amounts related to the Texas Electric Rate Case.

Interest Charges — Interest expenses increased $21 million year-to-date, largely due to the recognition of previously deferred amounts related to the Texas Electric Rate Case and increased long-term debt levels to fund capital investments.

Public Utility Regulation and Other

The FERC and state and local regulatory commissions regulate SPS. SPS is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in utility rates through commission filings. Changes in operating costs can affect SPS' financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and demand side management efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2021 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending and Recently Concluded Regulatory Proceedings

2021 Texas Electric Rate Case — In 2021, SPS filed an electric rate case with the PUCT and its municipalities seeking an increase in base rates of approximately $140 million. In May 2022, the PUCT approved a settlement between SPS and intervening parties, which reflects the following terms:

- Base rate increase of $89 million effective retroactively to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for AFUDC purposes only.
- Depreciation lives for Tolk accelerated to 2034 and Harrington coal assets accelerated to 2024.

In July 2022, SPS filed to surcharge the final under-recovered amount, estimated to be approximately $85 million, substantially offset by the recognition of previously deferred costs. The impact of the retroactive amounts is as follows:

(Millions of Dollars)	**Nine Months Ended Sept. 30, 2022**
Revenue surcharge accrual	$ 85
Depreciation and amortization	(43)
O&M expenses	(16)
Interest expense	(12)
Taxes other than income taxes	(10)
Fuel and purchased power	(2)

Table of Contents

Other

Supply Chain

SPS' ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Manufacturing processes have experienced disruptions related to scarcity of certain raw materials and interruptions in production and shipping. For example, availability of certain types of transformers has been significantly impacted and in some cases may result in delays in new customer connections as we work to address the shortage. These disruptions have been further exacerbated by inflationary pressures, labor shortages and the impact of international conflicts/issues. SPS continues to monitor the situation as it remains fluid and seeks to mitigate the impacts by securing alternative suppliers, modifying design standards, and adjusting the timing of work.

Inflation Reduction Act — In August 2022, the IRA was signed into law.

Key provisions impacting SPS include:

- Extends current PTC and ITC for renewable technologies (e.g., wind and solar).
- Restores full value of the PTC and ITC for qualifying facilities placed in-service after 2021.
- Creates a PTC for solar, clean hydrogen and nuclear.
- Establishes an ITC for energy storage, microgrids, interconnection facilities, etc.
- Allows companies to monetize or sell credits to unrelated parties.

SPS anticipates the IRA will drive significant customer savings for both new and existing Company owned renewable projects, assuming appropriate regulatory mechanisms and development of a market for the sale of tax credits. The IRA is expected to allow SPS to monetize tax credits more efficiently with the incremental benefits passed through to customers.

In addition, the IRA created a new corporate AMT. SPS does not anticipate AMT having a material cash impact based on current estimates and our interpretation of AMT application.

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, SPS incurred net natural gas, fuel and purchased energy costs of approximately $100 million (largely deferred as regulatory assets).

In 2021, SPS filed to recover $88 million of Winter Storm Uri costs over 24 months, as part of the Texas fuel surcharge filing, with total under-recovered costs of $121 million.

In April 2022, interim rates designed to recover $121 million over 30 months were approved. The interim rate recovery does not address the prudence of costs nor the retention of $10 million related to market sales during the event. These items will be reviewed through the triennial Fuel Reconciliation proceeding and are subject to a final PUCT decision.

In July 2022, the intervenors filed recommendations in the Fuel Reconciliation proceeding. The Texas Industrial Energy Consumers and PUCT staff recommended disallowances of approximately $10 million (off-system sales margins). The Office of Public Utility Counsel recommended disallowances of approximately $15 million (off-system sales margins and adjustment to energy loss factors). The Alliance of Xcel Municipalities recommended disallowances of approximately $100 million (natural gas storage, contracted capability and off-system sales margins).

A recommendation from the ALJ is expected in the fourth quarter of 2022 and a final decision is anticipated in the first quarter of 2023.

Environmental

Clean Air Act

In April 2022 the EPA proposed regulations under the "Good Neighbor" provisions of the Clean Air Act. The proposed rules impose a Federal Implementation Plan that establishes an allowance trading program for NOx, potentially impacting SPS generating facilities. Facilities without NOx controls will have to secure additional allowances, install NOx controls, or develop a strategy of operations that utilizes the existing allowance allocations. The EPA has indicated that it intends for the rule to be final by the end of 2022 with initial applicability for the 2023 ozone season. While the financial impacts of the proposed regulation are uncertain, SPS anticipates that costs will be recoverable through regulatory mechanisms.

CERCLA

PFAS are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. SPS does not manufacture PFAS but because PFAS are so ubiquitous in products and the environment, it may impact our operations. In September 2022, the EPA proposed to designate two types of PFAS as “hazardous substances” under the CERCLA, specifically perfluorooctanoic acid and perfluorooctanesulfonic acid. This proposed rule could result in new obligations for investigation and cleanup wherever PFAS are found to be present. The impact the proposed regulation may have on electric and gas utilities is currently uncertain.

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of Sept. 30, 2022, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2021, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation, dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	3.02
10.01*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, among Southwestern Public Service Company, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank PLC, as Syndication Agents, and Citibank, N.A., MUFG Bank, Ltd. and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated September 19, 2022	99.04
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Southwestern Public Service Company

10/27/2022	By:	/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer
		(Duly Authorized Officer and Principal Financial Officer)

THIS FILING IS
Item 1: ☐ An Initial (Original) Submission OR ☑ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

Exact Legal Name of Respondent (Company)	Year/Period of Report End of: 2021/ Q4

Southwestern Public Service Company	

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

N RAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain

Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Southwestern Public Service Company		02 Year/ Period of Report End of: 2021/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 790 South Buchanan Street, Amarillo, TX 79101		
05 Name of Contact Person Brian J. Van Abel		06 Title of Contact Person Executive Vice President, Chief Financial Officer
07 Address of Contact Person (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401		
08 Telephone of Contact Person, Including Area Code (612) 330-6747	09 This Report is An Original / A Resubmission (1) ☐ An Original (2) ☑ A Resubmission	10 Date of Report (Mo, Da, Yr) 05/24/2022

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Brian J. Van Abel	03 Signature Brian J. Van Abel	04 Date Signed (Mo, Da, Yr) 05/24/2022
02 Title Executive Vice President, Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Brian J. Van Abel

Executive Vice President and Chief Financial Officer

414 Nicollet Mall Minneapolis, MN 55401

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: NM

Date of Incorporation: 1921-08-17

Incorporated Under Special Law: N/A

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Southwestern Public Service Company (SPS) is an operating utility engaged primarily in the generation, purchase, transmission, distribution, and sale of electricity with operations in the states of Texas and New Mexico.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Southwestern Public Service Company (SPS) is a wholly-owned subsidiary of Xcel Energy, Inc.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
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Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	President	David T. Hudson	310,000	2021-01-01	2021-12-31
2	Chairman and Chief Executive Officer	Ben Fowke	[(a)]112,258	2021-01-01	2021-08-18
3	Executive Vice President, Chief Financial Officer	Brian J. Van Abel	85,530	2021-01-01	2021-12-31
4	Executive Vice President, General Counsel	Amanda J. Rome	69,523	2021-01-01	2021-12-31
5	Executive Vice President, Chief Human Resources Officer	Darla Figoli	64,657	2021-01-01	2021-12-31
6	Chairman and Chief Executive Officer	Robert C. Frenzel	[(b)]62,366	2021-08-18	2021-12-31
7	Executive Vice President, Chief Operating Officer	Robert C. Frenzel	[(c)]60,195	2021-01-01	2021-08-17
8	Executive Vice President, Chief Generations Officer	Timothy J. O'Connor	47,379	2021-08-18	2021-12-31
9	Executive Vice President, Chief Operations Officer	Timothy J. O'Connor	[(d)]39,667	2021-08-18	2021-12-31
10	Salaries represent Southwestern Public Co. allocation of officers' salaries greater than $50,000 for the period of time that was served as an officer for Southwestern Public Service Co.				

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OfficerSalary
Ben Fowke retired as Chairman and Chief Executive Officer effective August 18, 2021.
(b) Concept: OfficerSalary
Robert C. Frenzel was elected Chairman and Chief Executive Officer effective August 18, 2021.
(c) Concept: OfficerSalary
Robert C. Frenzel was elected Chairman and Chief Executive Officer effective August 18, 2021.
(d) Concept: OfficerSalary
Timothy J. O'Connor was elected Executive Vice President, Chief Operations Officer effective August 18, 2021.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	David T. Hudson, President	790 South Buchanan Street, Amarillo, TX 79170	true	false
2	[(a)] Ben Fowke, Chairman and Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	true
3	[(b)] Robert C. Frenzel, Chairman and Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	true
4	Brian J. Van Abel, Executive Vice Presndent and Chief Financial Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false
5	Robert C. Frenzel, Executive Vice President and Chief Operating Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector
Ben Fowke retired as Chairman and Chief Executive Officer effective August 18, 2021.
(b) Concept: NameAndTitleOfDirector
Robert C. Frenzel was elected Chairman and Chief Executive Officer effective August 18, 2021.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	FERC Electric Tariff, First Revised Volume No. 1. (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	(a) ER08-313-005
2	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 (Xcel Energy Operating Companies Joint Open Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.) Compliance Filing - corrected certificates of concurrence to the Xcel Energy Operating Companies Joint OATT.	(b) ER10-2075
3	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	(c) ER11-3505
4	FERC Electric Rate Schedule No. 102, Tariff ID 1000 (Public Service Company of New Mexico)	(d) ER11-3442
5	FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	(e) ER11-4082
6	FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	(f) ER11-4084
7	SPS FERC Electric Rate Schedule Second Revised No. 118, Tariff ID 1000. (Wholesale Full Requirements Service to Cap Rock Energy Corporation, now Sharyland Utilities.)	(g) EL05-19-000, et al., and ER05-168-000, et al.
8	FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	(h) EL05-19-000, ER05-168-000 and ER06-274-000
9	FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	(i) ER11-3228
10	FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	(j) ER11-3598
11	FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	(k) ER13-1451
12	FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	(l) ER13-1453
13	FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	(m) ER13-1455
14	FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	(n) ER13-1458
15	FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	(o) ER14-187
16	FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	(p) ER14-189
17	FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	(q) ER14-192

18	FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	[r] ER14-2921
19	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency)	[s] ER15-561
20	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	[t] ER-15-949
21	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001 (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[u] ER16-236
22	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	[v] ER16-520
23	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[w] ER16-1420
24	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[x] ER16-2597 and ER16-2598
25	FERC Electric Rate Schedule No. 136, Tariff ID 1001 (Tri-County Electric Cooperative, Inc.)	[y] ER17-267
26	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[z] ER18-1521
27	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[aa] ER18-2319
28	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[ab] ER19-675
29	FERC Electric Rate Schedule No. 138, Tariff ID 1001 (Lubbock Power & Light)	[ac] ER19-1727
30	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 137, and 138, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Tri-County Electric Cooperative, Inc., Lubbock Power & Light)	[ad] ER20-2824, EL21-58 and ER22-200
31	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 137, and 138, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Tri-County Electric Cooperative, Inc., Lubbock Power & Light)	[ae] ER21-73
32	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[af] ER21-2961
33	FERC Electric Tariff, First Revised Volume No. 1. (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[ag] ER08-313-002, 003, 004; ER08-923-001, 002, 003; ER08-1307-001, 002; ER08-1308-002, 003, 006; ER08- 1357-001, 002; ER08-1358-001, 002; ER08-1359-001, 002
34	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[ah] ER11-114
35	Second Revised FERC Rate Schedule No. 102, Tariff ID 1000 (Public Service Company of New Mexico)	[ai] ER10-260
36	SPS FERC Third Revised Rate Schedule Nos. 114, 115, 116, and 117, Tariff ID 1000. (Central Valley Electric Cooperative, Inc., Farmers Electric Cooperative of New Mexico, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc., respectively. Referred to as the New Mexico Cooperatives.)	[aj] EL05-19-000, et al., and ER05-168-000, et al.
37	FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	[ak] ER11-4083
38	FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	[al] ER11-4085

39	FERC Electric Rate Schedule No. 118, Tariff ID 1000 (Sharyland Utilities)	[am] ER11-2921
40	FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	[an] ER10-1426
41	First Revised FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	[ao] ER10-515
42	FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative, Inc.)	[ap] ER12-1122
43	FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	[aq] ER13-1452
44	FERC Electric Rate Schedule No. 118. Tariff ID 1000 (Sharyland Utilities)	[ar] ER13-1454
45	FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	[as] ER13-1456
46	FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	[at] ER14-186
47	FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	[au] ER14-188
48	FERC Electric Rate Schedule No. 118, Tariff ID 1000 (Sharyland Utilities)	[av] ER14-190
49	FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	[aw] ER14-191
50	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency)	[ax] ER14-2923
51	FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	[ay] ER15-562
52	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	[az] EL05-19, ER05-168, ER06-274, EL05-151, EL12-59, EL13-78, EL15-8, ER14-192, and ER15-949
53	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[ba] ER16-512
54	FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	[bb] ER16-920
55	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	[bc] ER16-1431
56	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 and 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	[bd] ER17-236 and ER17-238
57	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 136, and 137, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency, Tri-County Electric Cooperative, Inc.)	[be] ER18-228
58	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[bf] ER18-2410
59	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	[bg] ER19-404
60		[bh] ER19-1613

	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 136, and 137, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency, Tri-County Electric Cooperative, Inc.)	
61	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 136, 137, and 138, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency, Tri-County Electric Cooperative, Inc., Lubbock Power & Light)	(bi) ER20-277
62	FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	(bj) ER20-2829, EL21-58 and ER22-201
63	FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 137, and 138, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Tri-County Electric Cooperative, Inc., Lubbock Power & Light)	(bk) ER21-271

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ProceedingDocketNumber

SPS filing to implement a transmission formula rate. (Accession No. 20071210-0247.) Commission Order approving uncontested settlement to implement a transmission formula rate, except the issue of classifying radial transmission facilities, issued December 2, 2009, effective January 1, 2009 - 129 FERC 61,193 (2009) (Accession No. 20091202-3038.)

(b) Concept: ProceedingDocketNumber

Baseline Electronic Tariff Filing of the Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Second Revised Volume No. 1 and Related Tariff Records (Accession No. 20100730-5185.) Amended filing on September 28, 2010 (Accession No. 20100928-5287.) Letter order accepting filing and amendment issued October 25, 2010 effective July 30, 2010 (Accession No. 20101025-3018.)

(c) Concept: ProceedingDocketNumber

SPS submitted revised Attachment O-SPS formula rate template. The revised template converts the SPP Base Plan revenue requirement calculation from a historical basis to a projected basis along with a corresponding true-up to actual costs. The SPP Base Plan Upgrade revenue requirement is a component of of the SPS Annual Transmission Revenue Requirement (Accession No. 20110503-5076.) Letter order approving the revised tariff sheets issued July 1, 2011 effective July 5, 2011 (Accession No. 20110701-3027.)

(d) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Interruptible Power Service to Public Service Company of New Mexico (Accession No. 20110427-5155.) Letter order issued June 21, 2011 accepting the revised formula rate template effective January 1, 2010 (Accession No. 20110621-3042.)

(e) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Central Valley Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)

(f) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Lea County Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)

(g) Concept: ProceedingDocketNumber

Offer of settlement dated July 7, 2010 (Accession No. 20100708-0001.) Commission Order approving uncontested settlement issued on December 20, 2010 - 133 FERC 61,243 (2010) (Accession No. 20101220-3044.)

(h) Concept: ProceedingDocketNumber

Offer of uncontested partial settlement (Accession No. 20071204-0162.) Commission Order approving uncontested partial settlement subject to modification issued on April 21, 2008 - 123 FERC 61,054 (2008) (Accession No. 20080421-3030.)

(i) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Partial Requirements Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20110330-5101.) Letter Order issued May 4, 2011 accepting the revised formula rate template, effective January 1, 2010 (Accession No. 20110504-3040.)

(j) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Total Requirements Power Service to West Texas Municipal Power Agency (Accession No. 20110519-5016.) Letter Order issued June 24, 2011 accepting the revised formula rate template, effective January 1, 2010 (Accession No. 20110624-3044.)

(k) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Central Valley Electric Cooperative, Inc. (Accession No. 20130510-5095.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3018.)

(l) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Roosevelt County Electric Cooperative, Inc. (Accession No. 20130510-5097.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3021.)

(m) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20130510-5099.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3022.)

(n) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Farmers Electric Cooperative, Inc. (Accession No. 20130510-5102.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3024.)

(o) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to Farmers Electric Cooperative, Inc. (Accession No. 20131028-5002.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3018.)

(p) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to Roosevelt County Electric Cooperative, Inc. (Accession No. 20131028-5004.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3020.)

(q) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20131028-5007.) Commission Order approving revised formula rate template issued December 27, 2013 - 145 FERC 61,281 (2013) (Accession No. 20131227-3016.)

(r) Concept: ProceedingDocketNumber

Revised Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause and Revised Formula Rate Template for Partial Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20140922-5086.) Amended filing (Accession No. 20141007-5134.) Letter Order issued November 19, 2014 accepting revised template, effective March 1, 2014 (Accession No. 20141119-3046.)

(s) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to Central Valley Electric Cooperative, Inc., Farmers' Cooperative of New Mexico, Inc., Lea County Electric Cooperative, Inc., Roosevelt County Electric Cooperative, Inc., and West Texas Municipal Power Agency (Accession No. 20141203-5058.) Letter Order issued January 28, 2015 accepting revised template, effective January 1, 2014 (Accession No. 20150128-3055.)

(t) Concept: ProceedingDocketNumber

SPS CP Filing for Requirements Customers (Accession No. 20150130-5301). Offer of Settlement filed August 28, 2015 (Accession No. 20150828-5323). Letter Order issued October 29, 2015 accepting uncontested settlement re Golden Spread Electric Cooperative, Inc. et. al. (Accession No 20151029-3063). Compliance filing to implement tariff revisions as detailed in the Offer of Settlement (Accession No. 20151214-5234). Letter Order issued January 29, 2016 accepting revised templates (Accession No. 20160129-3034).

(u) Concept: ProceedingDocketNumber

Revisions to the tariff records to modify the SPS Transmission Formula Rates included in the Xcel Energy Tariff, dated November 2, 2015 to modify the manner in which SPS calculates average Accumulated Deferred Income Tax balances, in order to comply with Section 1.167(l)-1(h)(6)(ii) of IRS regulations, effective January 1, 2016 (Accession No. 20151102-5207). Additional revisions to the tariff records, in response to December 23, 2015 Deficiency Letter dated February 12, 2016 (Accession No. 20160212-5061). Order accepting tariff revisions, subject to conditions, dated April 12, 2016 (Accession No. 20160412-3053). Compliance Filings to implement tariff revisions effective January 1, 2016, and due to the transition to a new electronic tariff software product, the tariff revisions needed to also be effective April 16, 2016 (Docket No. ER16-1686), dated May 12, 1012 (Accession Nos. 20160512-5197 and 20160512-5202). Letter order accepting filings issued August 9, 2016 effective January 1, 2016 and April 16, 2016 (Accession No. 20160809-3024.)

(v) Concept: ProceedingDocketNumber

Revised formula rate template for Requirements customers to include a calculation to provide a rate base credit for certain unfunded reserves, dated December 14, 2015 (Accession No. 20151214-5245). Letter order issued January 29, 2016 approving filing effective January 1, 2016 (Accession No. 20161029-3035).

(w) Concept: ProceedingDocketNumber

Administrative filing to re-Baseline the Tariff Records currently filed under SPS's Tariff ID 2000 (SPS Transmission Tariffs) to new Tariff ID 2001 (Transmission and Service Agreements Tariff). This filing is to facilitate the transition to a new electronic tariff filing software, dated April 15, 2016 (Accession No. 20160415-5088). Letter order accepting filing issued June 7, 2016, effective April 16, 2016 (Accession No. 20160607-3006).

(x) Concept: ProceedingDocketNumber

Revisions to the Tariff Records to modify the SPS Transmission Formula Rates included in the Xcel Energy Tariff, dated September 16, 2016, to reflect a new SAP general ledger accounting system adopted by Xcel Energy Services Inc. and the Xcel Energy Operating Companies for fiscal year 2016, and other ministerial clean-up revisions to Attachment O-SPS (Accession Nos. 20160916-5048 and 20160916-5052) . Letter orders accepting tariff revisions effective January 1, 2016 April 16, 2016, dated November 9, 2016 (Accession Nos. 20161109-3044 and 20161109-3045).

(y) Concept: ProceedingDocketNumber

Revisions to Transaction Agreement with Tri-County Electric Cooperative, Inc. to convert to a Production Formula Rate, dated November 1, 2016 (Accession No. 20161101-5097). Letter order accepting filing effective January 1, 2017, dated February 17, 2017 (Accession No. 20170217-3013).

(z) Concept: ProceedingDocketNumber

Request for waiver of Formula Rate Implementation Procedures applicable to SPS's Attachment O in the Xcel Energy Tariff. The waiver allows SPS to revise the federal income rate input in its 2018 projected net revenue requirements to reflect the reduction in the federal rate (Accession No. 20180504-5171). Order granting request for waiver effective January 1, 2018 (Accession No. 20180531-5131).

(aa) Concept: ProceedingDocketNumber

Revisions to the tariff records to modify the calculation of Accumulated Deferred Income Tax ("ADIT") balances in the Transmission Formula Rate included in the Xcel Energy Tariff to comply with Section 1.167(l)-1(h)(6)(ii) of the IRS regulations. The revisions eliminate the "two step averaging" in calculating the projected annual transmission revenue requirement, estimated rates and formula rate true-up. (Accession No. 20180827-5098). Order on Paper Hearing and Accepting Proposed Tariff Revisions effective January 1, 2019, that will apply to true-up calculations to reflect the revisions as of June 27, 2018 (Accession No. 20181220-2032).

(ab) Concept: ProceedingDocketNumber

Revisions to the tariff records to the Xcel Energy Tariff to revise Attachment O-SPS to establish a new formula rate mechanism to calculate a monthly Wholesale Distribution Service Charge applied to SPS' transmission service customers that take delivery of energy from SPS at distribution voltage (less than 69 kV) delivery points (Accession No. 20181221-5281). Offer of Partial Settlement with Golden Spread Electric Cooperative filed February 21, 2020 (Accession No. 20200221-5045). Letter order approving Partial Settlement with Golden Spread Electric Cooperative dated May 26, 2020 (Accession No. 20200526-3064). Offer of Partial Settlement with Lubbock Power and Light filed May 29, 2020 (Accession No. 20200529-5150). Letter order approving Partial Settlement with Lubbock Power and Light dated September 1, 2020 (Accession No. 20200901-3061). Letter order accepting tariff revisions effective August 1, 2019, dated September 1, 2020 (Accession No. 20200901-3069).

(ac) Concept: ProceedingDocketNumber

Revisions to the Transaction Agreement between SPS and Lubbock Power & Light under which SPS will provide partial requirements service to LP&L commencing June 1, 2019 Revisions have been made to the Production Formula Rate Template, Implementation Procedures and the Fuel Clause (Accession No. 20190430-5314). Letter order accepting filing effective June 1, 2019, dated June 28, 2019 (Accession No. 20190628-3074).

(ad) Concept: ProceedingDocketNumber

Revisions to the Production Formula Rate Template to exclude costs associated with SPS's Advanced Grid Intelligence and Security ("AGIS") initiative from the determination of SPS's wholesale revenue requirement effective January 1, 2020 (Accession No. 20200904-5124). SPS filed a motion requesting to withdraw the filing and terminate the proceedings (Accession No. 20201203-5045). Order accepting motion to withdraw and institute a proceeding pursuant to Section 206 of the FPA (Docket No. EL21-58), establish a refund date, and establish hearing and settlement judge proceedings (Accession No. 20210422-3101). Offer of Settlement filed October 25, 2021, and new proceeding opened (Docket No. ER22-200) (Accession No. 20211025-5098).

(ae) Concept: ProceedingDocketNumber

Revisions to the Production Formula Rate Template, Implementation Procedure and the Fuel Clause to allow SPS to recover the costs of the Sagamore Wind Project. SPS is proposing (i) revisions effective January 1, 2020, to ensure that no costs associated with the Sagamore Wind Project are recovered from the production customers for the period of January through November 2020 ("removal revisions"); and (ii) effective December 1, 2020, revisions to include the costs benefits associated with the Sagamore Wind Project ("inclusion revisions") (Accession No. 20201008-5092). Letter order approving the removal revisions effective January 1, 2020 and the inclusion revisions effective December 1, 2020, dated December 7, 2020 (Accession No. 20201207-2052).

(af) Concept: ProceedingDocketNumber

Revisons to the tariff records to the Xcel Energy Tariff to revise Attachment O - SPS to implement a one-time credit to transmission customers in Zone 11 of the Southwest Power Pool, Inc. ("SPP"), related to the transition of a portion of Lubbock Power & Light load from SPP to the Electric Reliability Council of Texas ("ERCOT") (Accession No. 20210929-5080). Letter order approving the revisions effective October 1, 2021, dated November 24, 2011 (Accession No. 20211124-3035).

(ag) Concept: ProceedingDocketNumber

Settlement filed June 30, 2010 resolving all the remaining issues in the above dockets. Specifically, issues regarding the classification of certain SPS transmission facilities referred to as radial lines (Accession No. 20100701-0022.) Commission Order approving settlement, issued August 26, 2010 - 132 FERC 61,170 (2010) (Accession No. 20100826-3005.)

(ah) Concept: ProceedingDocketNumber

SPS submitted revised tariff records contained in Attachment O-SPS to the Xcel Energy Operating Companies Joint OATT. Certain terms and conditions of the settlement filed June 30, 2010 in Docket ER08-313 referenced above required changes to the SPS Transmission Formulaic Rates compared to the formula template currently on file (Accession No. 20101014-5060.) Letter order approving the revised tariff sheets issued December 21, 2010 (Accession No. 20101221- 3035.)

(ai) Concept: ProceedingDocketNumber

SPS submitted revisions to Interconnection Agreement between SPS and Public Service Company of New Mexico and to change the rates for interruptible power from a fixed production rate to a formula rate (Accession No. 20100204-0004.) Letter order issued January 5, 2010 accepting revised Interconnection Agreement and formula rate effective November 1, 2009 (Accession No. 20100105-3030.)

(aj) Concept: ProceedingDocketNumber

Offer of settlement dated January 19, 2010 (Accession No. 20100119-0048.) Commission Order approving uncontested settlement issued on June 22, 2010 - 131 FERC 61,260 (2010) (Accession No. 20100622-3002.)

(ak) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Farmers Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)

(al) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Roosevelt County Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)

(am) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Sharyland Utilities (Accession No. 20110218-5139.) Letter Order issued April 18, 2011 accepting the revised formula rate template, effective August 1, 2010. (Accession No. 20110418-3029.)

(an) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Partial Requirements Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20100611-0216.) Letter order issued August 3, 2010 accepting the revised formula rate template, effective July 1, 2008 (Accession No. 20100803-3036.)

(ao) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Service to West Texas Municipal Power Agency (Accession No. 20091231-0038.) Letter order issued February 18, 2010 accepting the Revised Transaction Agreement & Master Power and Sale Agreement, including the formula rate template, effective January 1, 2010 (Accession No. 20100218-3058.) (Accession No. 20100218-3058.)

(ap) Concept: ProceedingDocketNumber

Expanded Electric Rate Schedule for Partial Revenue Requirements to Golden Spread Electric (Accession No. 20120221-5133.) Letter Order issued April 17, 2012 accepting the expanded service and formula rate template, effective April 20, 2012 (Accession No. 20120417-3003.)

(aq) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Lea County Electric Cooperative, Inc. (Accession No. 20130510-5096.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3019.)

(ar) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to Sharyland Utilities (Accession No. 20130510-5098.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3020.)

(as) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Full Requirements Power Service to West Texas Municipal Power Agency (Accession No. 20130510-5100.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3023.)

(at) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to Central Valley Electric Cooperative, Inc. (Accession No. 20131028-5001.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3017.)

(au) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to Lea County Electric Cooperative, Inc. (Accession No. 20131028-5003.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3019.)

(av) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to Sharyland Utilities (Accession No. 20131028-5005.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3021.)

(aw) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Requirements Power Service to West Texas Municipal Power Agency (Accession No. 20131028-5006.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3022.)

(ax) Concept: ProceedingDocketNumber

Revised Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause and Revised Formula Rate Template for Requirements Power Service to Central Valley Electric Cooperative, Inc., Farmers' Electric Cooperative of New Mexico, Inc., Lea County Electric Cooperative, Inc., Roosevelt County Electric Cooperative, Inc., and West Texas Municipal Power Agency (Accession No. 20140922-5088.) Amended filing (Accession No. 20141007-5136.) Letter Order issued November 19, 2014 accepting revised template, effective March 1, 2014 (Accession No. 20141119-3045.)

(ay) Concept: ProceedingDocketNumber

Revised Formula Rate Template for Partial Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20141203-5059.) Letter Order issued January 28, 2015 accepting revised template, effective January 1, 2014 (Accession No. 20150128-3054.)

(az) Concept: ProceedingDocketNumber

Consolidation of Affected Dockets and Offer of Settlement (Accession No. 20150828-5323). Letter Order issued October 29, 2015 accepting uncontested settlement re Golden Spread Electric Cooperative, Inc. et. al. (Accession No 20151029-3063).

(ba) Concept: ProceedingDocketNumber

Compliance filing to implement changes to Transmission Formula Rate Template associated with uncontested settlement in Docket No. ER05-19, et. al. (Accession No. 20151029-3063). Letter Order issued January 29, 2016 accepting compliance filing (Accession No. 20160129-3036).

(bb) Concept: ProceedingDocketNumber

Filing to correct certain metadata associated with eTariff records filed in Docket ER13-1455 (Accession No. 20160210-5050). Amended filing to change effective date to April 20, 2012 (Accession No. 20160422-5144). Letter order issued June 9, 2016 approving filing effective April 20, 2012 (Accession No. 20160609-3042).

(bc) Concept: ProceedingDocketNumber

Administrative filing to re-Baseline the Tariff Records currently filed under SPS's Tariff ID 1000 (SPS Market Tariffs) to new Tariff ID 1001 (Production Tariffs). This filing is to facilitate the transition to a new electronic tariff filing software, dated April 15, 2016 (Accession No. 20160415-5177). Letter order accepting filing issued June 7, 2016, effective April 16, 2016 (Accession No. 20160607-3006).

(bd) Concept: ProceedingDocketNumber

Revisions to the Production Tariff records dated October 31, 2016 to reflect a new SAP general ledger accounting system adopted by Xcel Energy Services Inc. and the Xcel Energy Operating Companies for fiscal year Operating Companies for fiscal year 2016, and 2016, and other ministerial clean-up revisions (Accession Nos. 20161031-5200 and 20161031-5222). Submission of additional revisions to the Production Tariff records dated December 23, 2016 (Accession Nos. 20161223-5096 and 20161223-5102). Letter order accepting tariff revisions effective January 1, 2016 and April 16, 2016, dated February 15, 2017 (Accession No. 20170215-3030).

(be) Concept: ProceedingDocketNumber

Revisions to the Production Formula Rate Template Implementation Procedures to update the wholesale depreciation rates used to calculate the depreciation expense, based on a new depreciation study, effective January 1, 2018. (Accession No. 20171101-5294). Letter order accepting compliance filing to implement Settlement revisions to the Production Formula Rate Template effective January 1, 2018, dated June 21, 2019 (Accession No. 20190621-3057).

(bf) Concept: ProceedingDocketNumber

Revisions to the tariff records to the Xcel Energy Tariff to clearly identify the calculation of the operation and maintenance expenses charged to interconnecting generators under Section 10.5 of the pro forma Large Generator Interconnection Agreement and Section 4.1.2 of the pro forma Small Generator Interconnection Agreement (Accession No. 20180911-5120). Order accepting tariff revisions effective January 1, 2019, dated March 15, 2019 (Accession No. 20190315-3054).

(bg) Concept: ProceedingDocketNumber

Revisions to the tariff records to the Xcel Energy Tariff to revise Attachment O-SPS as follows: 1) update transmission depreciation rates; 2) revise the Template's Base Upgrade revenue requirement calculation to use the weighted average transmission depreciation rate; 3) revise the Template to recover certain wholesale regulatory commission expenses; 4) correct the allocation of transmission-specific ADIT; and 5) revise the methodology for calculating ADIT to amortize the "excess" ADIT caused by the TCJA and include the amortization in the income tax calculation, effective February 1, 2019 (Accession No. 20181127-5093). Offer of Settlement filed December 23, 2019 (Accession No. 20191223-5059). Letter order approving Settlement dated April 20, 2020 (Accession No. 20200420-3061). Letter order accepting tariff revisions effective February 1, 2019 dated September 1, 2020 (Accession No. 20200901-3026).

(bh) Concept: ProceedingDocketNumber

Revisions to the Production Formula Rate Template that will 1) permit SPS to allocate the capital investment costs and operations and maintenance cost associated with the Hale Wind Project using an energy allocator rather than a demand allocator; 2) permit SPS to pass-through to customer the benefits of production tax credits; and 3) establish initial depreciation rates for the Hale Wind Project (Accession No. 20190418-5116). Letter order accepting filing effective June 1, 2019, dated June 17, 2019 (Accession No. 20190617-3045).

(bi) Concept: ProceedingDocketNumber

Revisions to the Production Formula Rate Template, Implementation Procedures and the Fuel Clause to update the wholesale depreciation rates and to request revisions to implement the Margin Credit which is a 75%-25% margin sharing arrangement, effective January 1, 2020 (Accession No. 20191101-5075). Offer of Settlement filed April 1, 2021 (Accession No. 20210401-5300). Letter order approving Settlement dated May 28, 2021 (Accession No. 20210528-3033). Letter order accepting tariff revisions effective January 1, 2020, dated September 1, 2021 (Accession No. 20210901-3001). Letter order accepting Errata compliance filing effective January 1, 2020, dated March 1, 2022 (Accession No. 20220301-3045).

(bj) Concept: ProceedingDocketNumber

Revisions to the tariff records to the Xcel Energy Tariff to revise Attachment O - SPS, to exclude costs associated with SPS's Advanced Grid Intelligence and Security ("AGIS") initiative from the determination of SPS's wholesale revenue requirement effective January 1, 2020 (Accession No. 20200904-5124). SPS filed a motion requesting to withdraw the filing and terminate the proceedings (Accession No. 20201203-5047). Order accepting motion to withdraw and institute a proceeding pursuant to Section 206 of the FPA (Docket No. EL21-58), establish a refund date, and establish hearing and settlement judge proceedings (Accession No. 20210422-3101). Offer of Settlement filed October 25, 2021, and new proceeding opened (Docket No. ER22-201) (Accession No. 20211025-5099).

(bk) Concept: ProceedingDocketNumber

Revisions to the Production Formula Rate Template to allow SPS to recover Southwest Power Pool, Inc. ("SPP") administration service costs. Beginning January 1, 2021, SPP began separating its administrative service costs into four different categories of charges. Two of these categories should be reflected in the Production Templates. (Accession No. 20201030-3075). Letter order approving the revisions effective January 1, 2021, dated December 11, 2020 (Accession No. 20201211-3019).

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20211201-5272	12/01/2021	ER08-313-000	Informational Filing: Annual Update of 2021 Transmission Formula Rate, under ER08-313, et al.	Xcel Energy Operating Companies FERC Electric Tariff, Second Revised Volume No. 1 - Attachment O - SPS Southwestern Public Service Company Formulaic Rates
2	20220104-5192	01/04/2022	ER08-313-000	Errata Informational Filing: Annual Update of 2021 Transmission Formula Rate, under ER08-313, et al.	Xcel Energy Operating Companies FERC Electric Tariff, Second Revised Volume No. 1 - Attachment O - SPS Southwestern Public Service Company Formulaic Rates
3	20210526-5293	05/26/2021	EL05-19-000	Informational Filing: Annual Update of Formula Rates for Service to Central Valley Electric Cooperative Inc., Farmers Electric Cooperative of New Mexico Inc., Lea County Electric Cooperative Inc., Roosevelt County Electric Cooperative Inc., Tri-County Electric Cooperative Inc., and Lubbock Power & Light. (The Annual Update informational filing indicates the calculation of estimated rates for service to these customers for the upcoming rate year July 1, 2021 to June 30, 2022).	FERC Electric Rate Schedule No. 114
4			ER05-168-000		FERC Electric Rate Schedule No. 115
5			ER17-267-000		FERC Electric Rate Schedule No. 116
6			ER19-1727-000		FERC Electric Rate Schedule No. 117
7					FERC Electric Rate Schedule No. 136
8					FERC Electric Rate Schedule No. 138

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1		Not Applicable		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

Muleshoe, TX - Utility Electric - Expiration 3/8/2031 Sudan, TX - Utility Electric - Expiration 9/7/2031
None.
None.
None.
None.
See Note 3 of the Financial Statements on page 123 for disclosures regarding short-term borrowings, long-term debt and other financing instruments.
None.
Union Employees - 2.5% increase effective Nov. 1, 2021. Non-Union Employees - Base pay increase of 3.00 percent effective March 16, 2021.
See Note 7 of the Financial Statements on page 123 for further information on material legal proceedings.
None.
None.
Effective January 8, 2021, Wendy B. Mahling resigned as Vice President, Corporate Secretary. Effective March 16, 2021, Amy L. Schneider elected as Vice President, Corporate Secretary. Effective June 28, 2021, Paul A. Johnson elected as Vice President, Treasurer. Effective July 2, 2021, Sarah W. Soong resigned as Vice President, Treasurer. Effective August 18, 2021, Ben Fowke retired as Chairman and Chief Executive Officer. Effective August 18, 2021, Robert C. Frenzel elected as Chief Executive Officer. Effective August 18, 2021, Timothy J. O'Connor elected as Executive Vice President, Chief Operations Officer.
Not applicable as proprietary capital ratio is greater than 30 percent.

Page 108-109

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	[a]10,836,801,681	10,447,148,046
3	Construction Work in Progress (107)	200	170,971,664	146,724,801
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,007,773,345	10,593,872,847
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	2,896,834,618	2,676,883,920
6	Net Utility Plant (Enter Total of line 4 less 5)		8,110,938,727	7,916,988,927
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		8,110,938,727	7,916,988,927
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,840,206	5,435,620
19	(Less) Accum. Prov. for Depr. and Amort. (122)		980,293	789,699
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		4,754,749	4,042,176
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		[b]20,486,000	

29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		6,317,896	9,476,848
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		36,418,558	18,164,945
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)			
36	Special Deposits (132-134)			
37	Working Fund (135)		100,500	100,500
38	Temporary Cash Investments (136)		1,150,637	5,711,231
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		86,332,547	76,286,142
41	Other Accounts Receivable (143)		48,083,261	52,941,701
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		12,024,228	8,424,050
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		9,299,204	8,977,359
45	Fuel Stock (151)	227	21,738,911	9,329,532
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	23,244,700	21,575,849
49	Merchandise (155)	227	124,865	133,143
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	[g]6,168,263	[g]4,757,404
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		12,653,496	8,157,913
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		716,617	707,842

61	Accrued Utility Revenues (173)		124,903,622	114,790,216
62	Miscellaneous Current and Accrued Assets (174)		2	
63	Derivative Instrument Assets (175)		36,307,019	19,755,912
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		6,317,896	9,476,848
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		352,481,520	305,323,846
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		27,825,411	26,167,614
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	475,971,038	402,517,026
73	Prelim. Survey and Investigation Charges (Electric) (183)		(7,566)	11,493
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	74,937,761	12,479,591
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		20,206,334	21,047,893
82	Accumulated Deferred Income Taxes (190)	234	463,260,511	296,589,324
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		1,062,193,489	758,812,941
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		9,562,032,294	8,999,290,659

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlant

Includes operating leases in accordance with Accounting Standards Codification (ASC) Topic 842 and FERC Docket No. AI19-1-000.

Account 101.1		
Finance Lease Asset	$	—
Operating Right of Use Asset		463,485,261
Total	$	463,485,261

(b) Concept: OtherSpecialFunds

The balance is comprised of SPS's overfunded pension and benefit plan amounts in accordance with FERC Order AI07-1-000.

(c) Concept: AllowanceInventoryAndWithheld

The balance is comprised of Texas Renewable Energy Credit Allowances of $6,168,263

(d) Concept: AllowanceInventoryAndWithheld

The balance is comprised of Texas Renewable Energy Credit Allowances of $4,757,404

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	100	100
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		362,132,084	362,132,084
7	Other Paid-In Capital (208-211)	253	2,737,601,661	2,436,497,706
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	9,033,435	9,033,435
11	Retained Earnings (215, 215.1, 216)	118	513,099,266	509,364,134
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(1,208,905)	(1,349,978)
16	Total Proprietary Capital (lines 2 through 15)		3,602,590,771	3,297,610,611
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	2,700,000,000	2,450,000,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	350,000,000	350,000,000
22	Unamortized Premium on Long-Term Debt (225)		8,069,653	8,401,871
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		17,611,855	18,111,472
24	Total Long-Term Debt (lines 18 through 23)		3,040,457,798	2,790,290,399
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		[a]433,972,235	463,486,285
27	Accumulated Provision for Property Insurance (228.1)			

28	Accumulated Provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)		1,396,000	36,803,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		230,887	344,390
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		5,689,651	9,254,379
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		116,195,197	111,597,896
35	Total Other Noncurrent Liabilities (lines 26 through 34)		557,483,970	621,485,950
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		137,000,000	250,000,000
38	Accounts Payable (232)		178,553,628	203,563,055
39	Notes Payable to Associated Companies (233)		91,000,000	
40	Accounts Payable to Associated Companies (234)		15,897,820	17,470,065
41	Customer Deposits (235)		5,374,612	5,625,500
42	Taxes Accrued (236)	262	47,439,373	50,627,311
43	Interest Accrued (237)		29,812,443	28,168,541
44	Dividends Declared (238)		58,237,900	54,068,000
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		5,943,097	6,129,256
48	Miscellaneous Current and Accrued Liabilities (242)		1,059,188	1,162,317
49	Obligations Under Capital Leases-Current (243)		[b]29,513,027	28,168,814
50	Derivative Instrument Liabilities (244)		9,254,376	12,819,104
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		5,689,651	9,254,379
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		603,395,813	648,547,584
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	30	52,443
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	22,720,538	23,793,334

60	Other Regulatory Liabilities (254)	278	573,391,119	597,650,663
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	1,035,635	1,073,958
63	Accum. Deferred Income Taxes-Other Property (282)		[c]928,978,570	818,073,359
64	Accum. Deferred Income Taxes-Other (283)		231,978,050	200,712,358
65	Total Deferred Credits (lines 56 through 64)		1,758,103,942	1,641,356,115
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		9,562,032,294	8,999,290,659

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ObligationsUnderCapitalLeaseNoncurrent

Includes operating leases in accordance with Accounting Standards Codification (ASC) Topic 842 and FERC Docket No. AI19-1-000.

(b) Concept: ObligationsUnderCapitalLeasesCurrent

Includes operating leases in accordance with Accounting Standards Codification (ASC) Topic 842 and FERC Docket No. AI19-1-000.

(c) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	12/31/2020	410.1 & Adjustments	12/31/2021
Electric Distribution Plant	$ 268,333,157	$ 3,033,882	$ 271,367,039
Electric General Plant	54,326,834	(1,097,742)	53,229,092
Electric Intangible Plant	1,437,433	1,035,706	2,473,139
Electric Production Plant	347,317,018	69,320,282	416,637,300
Electric Transmission Plant	631,821,181	15,815,069	647,636,250
Electric Transmission-Production Plant	1,854,175	1,795,502	3,649,677
Non-Utility	3,050,947	(9,919)	3,041,028
Regulatory Difference - Prior Flow Thru	(532,054,329)	22,014,747	(510,039,582)
Regulatory Difference - AFUDC Equity	41,986,944	(1,002,316)	40,984,628
TOTAL Electric Plant	$ 818,073,360	$ 110,905,211	$ 928,978,571

FERC Account	Description	Page No.	Plant-Related Ending Balance
282	Accumulated Deferred Income Taxes - Other Property	275	$ 928,978,571
	Less: Non-utility Accumulated Deferred Income Taxes		(3,041,028)
	Unblended ADIT Adjustment Total Company - Wholesale Jurisdiction		(40,851,107)
	Wholesale Jurisdiction Accumulated Deferred Income Taxes		$ 885,086,436
	Other items included in Plant-282 Balance:		
	Texas Gross Margin Tax		(16,707,928)
	Restructuring Meters		(451,167)

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	2,280,498,583	1,733,917,146			2,280,498,583	1,733,917,146				
3	Operating Expenses											
4	Operation Expenses (401)	320	(a)1,449,481,714	(i)1,015,368,224			1,449,481,714	1,015,368,224				
5	Maintenance Expenses (402)	320	56,876,253	51,848,886			56,876,253	51,848,886				
6	Depreciation Expense (403)	336	303,401,608	254,485,113			303,401,608	254,485,113				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	2,987,233	2,121,474			2,987,233	2,121,474				
8	Amort. & Depl. of Utility Plant (404-405)	336	24,920,299	25,915,894			24,920,299	25,915,894				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											

12	Regulatory Debits (407.3)		[b]2,723,448	[j]4,969,783			2,723,448	4,969,783				
13	(Less) Regulatory Credits (407.4)		[c]26,208,109	[k]65,649,002			26,208,109	65,649,002				
14	Taxes Other Than Income Taxes (408.1)	262	87,916,885	87,010,184			87,916,885	87,010,184				
15	Income Taxes - Federal (409.1)	262	[d](11,097,493)	[l](31,502,626)			(11,097,493)	(31,502,626)				
16	Income Taxes - Other (409.1)	262	[e](653,167)	[m](1,575,461)			(653,167)	(1,575,461)				
17	Provision for Deferred Income Taxes (410.1)	234, 272	173,009,231	127,163,377			173,009,231	127,163,377				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	221,308,664	104,247,526			221,308,664	104,247,526				
19	Investment Tax Credit Adj. - Net (411.4)	266	[f](52,413)	[n](52,421)			(52,413)	(52,421)				
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		[g]1,558,887	[o]133,935			1,558,887	133,935				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		4,548,910	3,652,390			4,548,910	3,652,390				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,844,986,848	1,369,374,354			1,844,986,848	1,369,374,354				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		435,511,735	364,542,792			435,511,735	364,542,792				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)		200,505	162,362								
34	(Less) Expenses of Nonutility Operations (417.1)		306,938	270,031								
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		1,534,841	844,877								
38	Allowance for Other Funds Used During Construction (419.1)		4,054,895	33,470,912								
39	Miscellaneous Nonoperating Income (421)		1,405,367	15,140								
40	Gain on Disposition of Property (421.1)		331	[p](10,465)								
41			6,889,001	34,212,795								

	TOTAL Other Income (Enter Total of lines 31 thru 40)											
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		15	109,478								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		419,138	413,634								
46	Life Insurance (426.2)		[b](32,946)	[g](23,429)								
47	Penalties (426.3)		54,962	69,403								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		680,221	575,905								
49	Other Deductions (426.5)		207,888	194,204								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,329,278	1,339,195								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	23,232	20,864								
53	Income Taxes-Federal (409.2)	262	355,084	83,408								
54	Income Taxes-Other (409.2)	262	203,553	[e](3,332)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	77,136	244,626								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272										
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		659,005	345,566								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,900,718	32,528,034								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		119,478,806	108,742,729								
63	Amort. of Debt Disc. and Expense (428)		1,888,510	1,711,774								
64	Amortization of Loss on Reaquired Debt (428.1)		841,559	815,500								
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		152,595	470,970								
68	Other Interest Expense (431)		1,719,233	4,862,816								

69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,745,281	14,319,063								
70	Net Interest Charges (Total of lines 62 thru 69)		122,335,422	102,284,726								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		318,077,031	294,786,100								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		318,077,031	294,786,100								

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OperationExpense

Includes $17 million of demand-side management program expenses.

(b) Concept: RegulatoryDebits

NM RPS Rider Amort	$	2,168,059
TX Restruct Recoverable Meter		34,899
NM Z2 Amort		520,490
	$	2,723,448

(c) Concept: RegulatoryCredits

TX 47527 Revenue Surcharge Accrual	$	13,825,765
ARO Reg Credits Electric		7,536,143
2019 Over Recovery Amort		2,757,010
2019 TOTI Amort		1,966,895
Amort of Inc Capital RL		53,949
2019 Over Recovery Interest Amort		68,347
	$	26,208,109

(d) Concept: IncomeTaxesOperatingIncome

Unnatural balances in FERC 409.1 are not uncommon as the provision accruals may result in a tax benefit instead of a tax expense throughout the year.

(e) Concept: IncomeTaxesUtilityOperatingIncomeOther

Unnatural balances in FERC 409.1 are not uncommon as the provision accruals may result in a tax benefit instead of a tax expense throughout the year.

(f) Concept: InvestmentTaxCreditAdjustments

Unnatural balances in FERC 411.4 are not uncommon as the provision accruals may result in a tax benefit instead of a tax expense throughout the year.

(g) Concept: GainsFromDispositionOfAllowances

Column c & g		**Current Year**
TX REC Sale	$	1,558,940
NM REC Sale		(61)
SO2 Auction		18
SO2 Sharing		(10)
	$	1,558,887

(h) Concept: LifeInsurance

Income on Company owned life insurance.

(i) Concept: OperationExpense

Includes $16 million of demand-side management program expenses.

(j) Concept: RegulatoryDebits

TX 47527 TCRF Billings	$	(100)
Hale Excess Over Revenue Requirement		(77,703)
NM RPS Rider Amort		2,266,136
TX Restruct Recoverable Meter		34,899
NM Z2 Amort		520,490
TX Z2 Amort		(396,466)
SPS TX 2019 RETAIL		2,622,527
	$	4,969,783

(k) Concept: RegulatoryCredits

ARO Reg Credits Electric	$	5,773,864
Amort of Inc Capital RL		53,949
NM Lg Cust Cap Amort		2,395,569
TX 49831 Cost Deferrals		56,369,134
TX 47527 Settlement		186
NM 2018 Over recovery and interest		1,056,300
	$	65,649,002

(l) Concept: IncomeTaxesOperatingIncome

Unnatural balances in FERC 409.1 are not uncommon as the provision accruals may result in a tax benefit instead of a tax expense throughout the year.

(m) Concept: IncomeTaxesUtilityOperatingIncomeOther

Unnatural balances in FERC 409.1 are not uncommon as the provision accruals may result in a tax benefit instead of a tax expense throughout the year.

(n) Concept: InvestmentTaxCreditAdjustments

Unnatural balances in FERC 411.4 are not uncommon as the provision accruals may result in a tax benefit instead of a tax expense throughout the year.

(o) Concept: GainsFromDispositionOfAllowances

Column d & h		Previous Year
TX REC Sale	$	22,751
NM REC Sale		(35)
2018 REC Sale		111,157
SO2 Auction		21
SO2 Sharing		41
	$	133,935

(p) Concept: GainOnDispositionOfProperty

Correcting entry to appropriately classify gain recognized from 2017 sale of property.

(q) Concept: LifeInsurance

Income on Company owned life insurance.

(r) Concept: IncomeTaxesOther

Unnatural balances for FERC 409 are relatively common because there is not an account for income tax benefits. Therefore, all income tax benefits and detriments are recorded in current tax expense.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		509,364,134	534,982,517
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Reclassification of Tax Effects from Account 219			(171,783)
9	TOTAL Credits to Retained Earnings (Acct. 439)			[a](171,783)
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		318,077,031	294,786,100
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1			(314,341,900)	(320,232,700)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(314,341,900)	(320,232,700)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		513,099,266	509,364,134
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			

46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		513,099,266	509,364,134
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AdjustmentsToRetainedEarningsCredit

On May 7, 2020 the FERC issued guidance in Docket No. A120-2-000 approving use of Account 439, Adjustments to Retained Earnings, to record the cumulative adjustment to beginning retained earnings for the implementation of Accounting Standards Update (ASU) No. 2016-13, Financial Instruments - Credit Losses (Topic 326).

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	318,077,031	294,786,100
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	310,937,751	260,258,977
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Assets and Liabilities	2,730,069	2,527,274
5.2	Impairment of Software and Others	(23,484,661)	(60,679,219)
5.3	Amortization of Premium, Discount, and Debt Expense	24,920,299	25,915,894
8	Deferred Income Taxes (Net)	(48,222,297)	23,160,477
9	Investment Tax Credit Adjustment (Net)	(52,413)	(52,421)
10	Net (Increase) Decrease in Receivables	(1,702,509)	(21,010,959)
11	Net (Increase) Decrease in Inventory	(19,666,951)	(34,371,273)
12	Net (Increase) Decrease in Allowances Inventory	(1,410,859)	(1,003,500)
13	Net Increase (Decrease) in Payables and Accrued Expenses	6,800,444	22,365,881
14	Net (Increase) Decrease in Other Regulatory Assets	(100,296,334)	(66,680,641)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(17,613,890)	(56,242,056)
16	(Less) Allowance for Other Funds Used During Construction	4,054,895	33,470,912
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Change in Accrued Utility Revenues	(10,113,406)	58,860
18.2	Change in Other Current Assets and Liabilities	(7,672,267)	(3,440,369)
18.3	Net Derivative Gains (Losses)	(2,753,910)	(139,535)
18.4	Change in Other Noncurrent Liabilities and Deferred Amounts	(67,044,247)	61,074,441

22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	359,376,955	413,057,019
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(583,140,907)	(1,174,567,049)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(404,586)	(808,339)
30	(Less) Allowance for Other Funds Used During Construction	(4,054,895)	(33,470,912)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(579,490,598)	(1,141,904,476)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Other: Investments in Utility Money Pool	(83,000,000)	(4,000,000)
53.2	Other: Repayments from Utility Money Pool	83,000,000	4,000,000
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(579,490,598)	(1,141,904,476)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	246,621,093	342,679,668

62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Capital Contributions from Parent	301,103,956	438,100,228
64.2	Other: Borrowings Under Utility Money Pool	539,000,000	561,000,000
66	Net Increase in Short-Term Debt (c)	(113,000,000)	250,000,000
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	973,725,049	1,591,779,896
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other: Repayments Under Utility Money Pool	(448,000,000)	(561,000,000)
76.2	Taxes Paid for Equity Based Awards		(318,637)
76.3	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(310,172,000)	(312,446,775)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	215,553,049	718,014,484
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(4,560,594)	(10,832,973)
88	Cash and Cash Equivalents at Beginning of Period	[(a)]5,811,731	16,644,704
90	Cash and Cash Equivalents at End of Period	[(b)]1,251,137	[(c)]5,811,731

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: CashAndCashEquivalents

Cash (131)	$	—
Working Fund (135)		100,500
Temporary Cash Investments (136)		5,711,231
	$	5,811,731

(b) Concept: CashAndCashEquivalents

Cash (131)	$	—
Working Fund (135)		100,500
Temporary Cash Investments (136)		1,150,637
	$	1,251,137

(c) Concept: CashAndCashEquivalents

Cash (131)	$	—
Working Fund (135)		100,500
Temporary Cash Investments (136)		5,711,231
	$	5,811,731

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

NOTES TO FINANCIAL STATEMENTS (Continued)

1. Use this space to paste the disclosure required by instruction 1 of Page 122.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the Southwest Public Service Company's (SPS) Annual Report on Federal Energy Regulatory Commission (FERC) Form 1 for the year ended Dec. 31, 2021, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Business and System of Accounts - SPS is a wholly-owned subsidiary of Xcel Energy Inc. that is principally engaged in the generation, purchase, transmission, distribution and sale of electricity. SPS is subject to regulation by the FERC and state utility commissions.

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Deferred financing costs are included as deferred debits in the FERC presentation in contrast to the GAAP presentation in which they are included as a deduction from the carrying amount of long-term debt.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits.
- Unrecognized tax benefits are recorded for temporary adjustments in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to its GAAP presentation as taxes accrued and other noncurrent liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation within the utility plant accounts in the FERC presentation and regulatory liabilities in the GAAP presentation.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for FERC presentation; however the net margin is reported as net sales for GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income and deductions for FERC presentation and reported as operating expenses for GAAP presentation.
- Income tax expense related to utility operations is shown as a component of utility operating expenses in the FERC presentation, in contrast to its GAAP presentation as a below-the-line deduction from operating income.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP. While for FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Non-service cost components of net periodic benefit costs that are reported on the income statement are recorded as operation expenses in the FERC presentation and as other income, net for GAAP presentation. Non-service costs that are eligible for capitalization are recorded as a component of net utility plant in the FERC presentation and as regulatory assets for GAAP.

If GAAP were followed these financial statement line items would have values greater/(lesser) than those shown by FERC presentation of:

(Millions of Dollars)		
Balance Sheet:		
Net utility plant	$	(273)
Current assets		196
Current liabilities		60
Other long-term assets		(223)
Long-term debt and other long-term liabilities		(360)
Statement of Income:		
Operating revenue	$	185
Operating expenses		254
Other income and deductions		—
Interest charges		(10)
Statement of Cash Flows:		
Cash provided by operating activities	$	—
Cash used in investing activities		(1)
Cash provided by financing activities		—

Use of Estimates — SPS uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — SPS accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, SPS may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on SPS' results of operations, financial condition and cash flows.

See Note 2 for further information.

Income Taxes — SPS accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. SPS defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. SPS uses rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of SPS' tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which would be refundable to utility customers over the remaining life of the related assets. SPS anticipates that a tax rate increase would result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal investment tax credits related to public utility

property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

SPS follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. SPS recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

SPS reports interest and penalties related to income taxes within other (expense) income or interest charges in the statements of income.

Xcel Energy Inc. and its subsidiaries, including SPS, file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 4 for further information.

Utility Plant and Depreciation in Regulated Operations — Utility plant is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and allowance for funds used during construction (AFUDC). The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Utility plant is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in utility plant that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

SPS records depreciation expense using the straight-line method over the plant's commission-approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are recovered in rates as authorized by the appropriate regulatory entities. The amount of removal costs is based on current factors used in existing depreciation rates. Depreciation expense, expressed as a percentage of average depreciable property, was 3.3% in 2021 and 3.1% in 2020.

AROs — SPS accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 7 for further information.

Benefit Plans and Other Postretirement Benefits — SPS maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 6 for further information.

Environmental Costs — Environmental costs are recorded when it is probable SPS is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for SPS' expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 7 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. SPS recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized.

SPS does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. SPS presents its revenues net of any excise or sales taxes or fees.

SPS participates in Southwest Power Pool, Inc. (SPP). SPS recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through regional transmission organizations (RTOs) are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO are recorded on a net basis in cost of sales.

Cash and Cash Equivalents — SPS considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. SPS establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

As of Dec. 31, 2021 and 2020, the allowance for bad debts was $12 million and $8 million, respectively.

Inventory — Inventory is recorded at average cost.

Fair Value Measurements — SPS presents cash equivalents, interest rate derivatives and commodity derivatives at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, SPS may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the pension and postretirement plan assets published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 5 and 6 for further information.

Derivative Instruments — SPS uses derivative instruments in connection with its utility commodity price and interest rate activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on expected recovery of derivative instrument settlements through fuel and purchased energy cost recovery mechanisms. Interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — SPS enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

Commodity Trading Operations — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of the commodity trading margins from Public Service Company of Colorado (PSCo) are apportioned to NSP-Minnesota and SPS. Commodity trading activities are not associated with energy produced from PSCo's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income

(for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in SPS' rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including demand side management (DSM) programs) qualify as alternative revenue programs. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate or from other instances where the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

Conservation Programs — SPS has implemented programs in its jurisdictions to assist customers in conserving energy and reducing peak demand on the electric system. These programs include commercial motor, air conditioner and lighting upgrades, as well as residential rebates for participation in air conditioner interruption and home weatherization.

The costs incurred for some DSM programs are deferred as permitted by the applicable regulatory jurisdiction. For those programs, costs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Revenues recognized for incentive programs designed for recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned. SPS recovers approved conservation program costs in base rate revenue or through a rider.

Emission Allowances — Emission allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

Renewable Energy Credits (RECs) — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. SPS reduces recoverable fuel and purchased power costs for the cost of RECs received. An inventory accounting model is used to account for RECs recognized on the balance sheet, however these assets are classified as regulatory assets if amounts are recoverable in future rates.

Sales of RECs are recorded in electric revenues on a gross basis. Cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Segment Information — SPS has only one reportable segment. SPS is a wholly owned subsidiary of Xcel Energy Inc. and operates in the regulated electric utility industry providing wholesale and retail electric service in the states of Texas and New Mexico.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2021 up to Feb. 23, 2022, the date of SPS' GAAP financial statements were issued, and has updated such evaluation for disclosure purposed through the date of this filing. These financial statements contain all necesary adjustments and disclosures resulting from that evaluation.

2. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric rates. SPS would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	Remaining Amortization Period	Dec. 31, 2021	Dec. 31, 2020
Pension and retiree medical obligations	Various	$ 142	$ 185
Excess deferred taxes — TCJA	Various	51	53
Recoverable deferred taxes on AFUDC	Plant lives	41	42
Net AROs [(a)]	Various	40	33
Conservation programs [(b)]	One to two years	3	1
Deferred natural gas and electric energy/fuel costs	One to three years	150	—
Other	Various	49	89
Total regulatory assets		$ 476	$ 403

(a) Includes amounts recorded for future recovery of AROs.
(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	Remaining Amortization Period	Dec. 31, 2021	Dec. 31, 2020
Deferred income tax adjustments and TCJA refunds [(a)]	Various	$ 492	$ 518
Gain from asset sales	Various	2	2
Deferred natural gas and electric energy/fuel costs	Various	—	35
Conservation programs	Less than one year	5	4
Other	Various	74	39
Total regulatory liabilities		$ 573	$ 598

(a) Includes the revaluation of recoverable/regulated plant accumulated deferred income taxes and revaluation impact of non-plant accumulated deferred income taxes due to the TCJA.

At Dec. 31, 2021 and 2020, SPS' regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, SPS' regulatory assets included $292 million and $114 million at Dec. 31, 2021 and 2020, respectively, of past expenditures not earning a return. Amounts are related to the Texas deferred fuel balance, losses on reacquired debt and certain rate case expenditures.

3. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for SPS:

	Year Ended Dec. 31	
(Amounts in Millions, Except Interest Rates)	2021	2020
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	91	—
Average amount outstanding	51	43
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	0.05 %	0.54 %
Weighted average interest rate at period end	0.05	N/A

Commercial Paper — Commercial paper outstanding for SPS:

	Year Ended Dec. 31	
(Amounts in Millions, Except Interest Rates)	2021	2020
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	137	250
Average amount outstanding	63	44
Maximum amount outstanding	342	250
Weighted average interest rate, computed on a daily basis	0.21 %	1.11 %
Weighted average interest rate at period end	0.26	0.29

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. At both Dec. 31, 2021 and 2020, there were $2 million of letters of credit outstanding under the credit facility. Amounts approximate their fair value and are subject to fees.

Credit Facility — In order to issue its commercial paper, SPS must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of SPS' credit facility:

Debt to Capitalization Ratio [(a)]		Amount Facility May Be Increased (millions of dollars)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
2021	2020		
47%	48%	$50	2

(a) The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal 65%.
(b) All extension requests are subject to majority bank group approval.

All extension requests are subject to majority bank group approval.

The credit facility has a cross-default provision that SPS would be in default on its borrowings under the facility if SPS or any of its future significant subsidiaries whose total assets exceed 15% of SPS' total assets default on indebtedness in an aggregate principal amount exceeding $75 million.

If SPS does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2021, SPS was in compliance with all financial covenants.

SPS had the following committed credit facility available as of Dec. 31, 2021 (in millions) of dollars:

Credit Facility [a]	Drawn [b]	Available
$ 500	$ 139	$ 361

[a] This credit facility matures in June 2024.
[b] Includes letters of credit and outstanding commercial paper.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the facility outstanding at Dec. 31, 2021 and 2020.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of SPS is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long-term debt obligations for SPS as of Dec. 31 (in millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	3.30%	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds	4.40	Nov. 15, 2048	300	300
First mortgage bonds	3.75	June 15, 2049	300	300
First mortgage bonds [b]	3.15	May 1, 2050	350	350
First mortgage bonds [a]	3.15	May 1, 2050	250	0
Unamortized discount			(9)	(10)
Unamortized debt issuance cost			(28)	(26)
Total long-term debt			$ 3,013	$ 2,764

[a] 2020 financing re-opened in 2021.
[b] 2020 financing.

Maturities of long-term debt:

(Millions of Dollars)	
2022	$ —
2023	—
2024	350
2025	—
2026	—

Capital Stock — SPS has the following preferred stock:

Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2021 and 2020
10,000,000	1	—

Dividend Restrictions — SPS dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. SPS is required to be current on particular interest payments before dividends can be paid.

SPS' state regulatory commissions additionally impose dividend limitations, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2021:

Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual [a]
Low	High	2021
45.0%	55.0%	54.5%

[a] Excludes short-term debt.

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization [a]
$513 million	$6,615 million	N/A

[a] SPS may not pay a dividend that would cause it to lose its investment grade bond rating.

4. Income Taxes

Federal Tax Loss Carryback Claims — In 2020, Xcel Energy identified certain expenses related to tax years 2009 - 2011 that qualify for an extended carryback claim. SPS is not expected to accrue any income tax expense related to this adjustment.

Federal Audits — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Years	Expiration
2014 — 2016	December 2022
2018	September 2022

Additionally, the statute of limitations related to certain federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to a federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2021, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2016. In April 2021, Texas began an audit of tax years 2016 - 2019. As of Dec. 31, 2021, no material adjustments have been proposed.

Uncertainty in Income Taxes – The FERC has not fully adopted the guidance for uncertainty in income taxes. Accordingly, NS-Wisconsin has recorded its unrecognized tax benefits for temporary adjustments, including NOL and tax credit carryforwards, in accounts established for accumulated deferred income taxes.

Unrecognized Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the effective tax rate (ETR). In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the timing of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	$ 4	$ 3
Unrecognized tax benefit — Temporary tax positions	4	4
Total unrecognized tax benefit	$ 8	$ 7

Changes in unrecognized tax benefits:

(Millions of Dollars)	2021	2020
Balance at Jan. 1	$ 7	$ 5
Additions based on tax positions related to the current year	1	1
Additions for tax positions of prior years	—	5
Reductions for tax positions of prior years	—	(4)
Balance at Dec. 31	$ 8	$ 7

Unrecognized tax benefits were reduced by tax benefits associated with net operating loss (NOL) and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	$ (7)	$ (6)

As the Internal Revenue Service (IRS) progresses its review of the tax loss carryback claim and as state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $5 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2021	2020
(Payable) receivable for interest related to unrecognized tax benefits at Jan. 1	$ (1)	$ 1
Interest expense related to unrecognized tax benefits	—	(2)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (1)	$ (1)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2021 or 2020.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2021	2020
Federal NOL carryforward	$ 336	$ —
Federal tax credit carryforwards	190	85
State NOL carryforwards	111	1

Federal carryforward periods expire between 2031 and 2041 and state carryforward periods expire starting 2034.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2021	2020 [(a)]
Federal statutory rate	21.0%	21.0%
State income tax on pretax income, net of federal tax effect	2.5	2.3
Increases (decreases) in tax from:		
Wind PTCs	(39.7)	(18.3)
Plant regulatory differences [(b)]	(4.7)	(6.4)
Amortization of excess nonplant deferred taxes	(1.1)	(0.8)
Other, net	(1.0)	(1.3)
Effective income tax rate	(23.0)%	(3.5)%

(a) Prior periods have been reclassified to conform to current year presentation.
(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2021	2020
Current federal tax benefit	$ (11)	$ (31)
Current state tax benefit	(1)	(1)
Current change in unrecognized tax expense (benefit)	1	(1)
Deferred federal tax (benefit) expense	(57)	15
Deferred state tax expense	9	8
Total income tax benefit	$ (59)	$ (10)

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2021	2020
Deferred tax (benefit) expense excluding items below	$ (24)	$ 55
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(24)	(31)
Tax benefit allocated to other comprehensive income, net of adoption of Financial Accounting Standards Board (FASB) Accounting Standard Codification (ASC) Topic 326, and other	—	(1)
Deferred tax (benefit) expense	$ (48)	$ 23

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2021	2020 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 1,047	$ 944
Operating lease assets	103	109

Regulatory assets	(58)	(68)
Deferred fuel costs	34	—
Pension expense	34	33
Other	2	2
Total deferred tax liabilities	$ 1,162	$ 1,020
Deferred tax assets:		
Operating lease liabilities	$ 103	$ 109
Regulatory liabilities	(25)	(24)
Differences between book and tax bases of property	91	92
Tax credit carryforward	190	85
NOL carryforward	76	—
Other employee benefits	7	7
Deferred fuel costs	—	9
Other	21	19
Total deferred tax assets	463	297
Net deferred tax liability	$ 699	$ 723

(a) Prior periods have been reclassified to conform to current year presentation.

In December 2017, SPS remeasured our deferred tax assets and liabilities to the new federal corporate income tax rate of 21%. After filing the 2017 tax return, we completed a final remeasurement of our 2017 deferred tax assets and liabilities to the new corporate tax rate. SPS received guidance from all jurisdictions in 2018-2020 and started the amortization of the deficient and excess accumulated deferred income tax (ADIT) for those jurisdictions. The Protected ADITs, which are required by IRS normalization rules to be provided to customers, are amortized according to the rules of the Average Rate Assumption Method (ARAM) with amortization occurring over the remaining book life of the individual assets. The Unprotected ADITs, are amortized according to each jurisdiction. The Nonplant Unprotected have amortization periods of 5 years. While, Plant Unprotected will use ARAM.

The amount of deficient and excess accumulated deferred income tax assets and liabilities that are considered protected and unprotected as of December 31, 2021 and 2020 is reflected below.

(Millions of Dollars)	Dec. 31, 2021		Dec. 31, 2020	
Account	182.3	254	182.3	254
Projected				
Plant	$ —	$ 426	$ —	$ 443
Nonplant	51	—	51	—
Unprotected				
Plant	—	57	—	61
Nonplant	1	9	2	14
Total				
Plant	$ —	$ 483	$ —	$ 504
Nonplant	$ 52	$ 9	$ 53	$ 14

Excess and deficient accumulated deferred income taxes in 2021 were amortized in the Statement of Income as follows:

(Millions of Dollars)	Dec. 31, 2021
Protected	
Plant	$ (10)
Nonplant	1
Unprotected	
Plant	(3)
Nonplant	(4)
Total	
Plant	$ (13)
Nonplant	$ (3)

5. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by SPS include transmission congestion instruments, generally referred to as financial transmission rights (FTRs), purchased from Southwest Power Pool, Inc (SPP). FTRs purchased from a regional transmission organization (RTO) are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of Sept. 30, 2021, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

(Amounts in Millions) [(a)]	Dec. 31, 2021	Dec. 31, 2020
Megawatt hours (MWh) of electricity	8	5

(a) Amounts are not reflective of net positions in the underlying commodities.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts, prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the balance sheets.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

SPS' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. At Dec. 31, 2021, two of the eight most significant counterparties for these activities, comprising $8 million or 24% of this credit exposure, had investment grade ratings from S&P, Moody's or Fitch Ratings. Five of the eight most significant counterparties, comprising $26 million or 76% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount or less than 1% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — Changes in the fair value of FTRs resulting in a pre-tax net gain of $28 million in Dec. 31, 2021 and $7 million in pre-tax net losses in the year ended Dec. 31, 2020, were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains were $20 million for the year ended Dec. 31, 2021. For the year ended Dec. 31, 2020, FTR settlement losses were immaterial. Settlement gains and losses were recognized and recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2021 or 2020

Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis:

	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 27	$ 27	$ —	$ 27	$ —	$ —	$ 7	$ 7	$ —	$ 7
Total current derivative assets	$ —	$ —	$ 27	$ 27	$ —	27	$ —	$ —	$ 7	$ 7	$ —	7
Purchase Power Agreements (PPAs) [(b)]						3						3
Current derivative instruments						$ 30						$ 10
Noncurrent derivative assets												
PPAs						$ 6						$ 9
Noncurrent derivative instruments						$ 6						$ 9

	Sept. 30, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative liabilities												
Other derivative instruments:												
PPAs [(b)]						$ 4						$ 4
Current derivative instruments						$ 4						$ 4
Noncurrent derivative liabilities												
PPAs [(b)]						$ 6						$ 9
Noncurrent derivative instruments						$ 6						$ 9

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2021 and 2020. At Dec. 31, 2021 and 2020, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2021 and 2020:

	Year Ended Dec. 31	
(Millions of Dollars)	2021	2020
Balance at Jan. 1	$ 7	$ 12
Purchases	10	23
Settlements	(79)	(23)
Net transactions recorded during the period:		
Net gains (losses) recognized as regulatory assets and liabilities	89	(5)
Balance at Dec. 31	$ 27	$ 7

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for Dec. 31, 2021 or 2020.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	Dec. 31, 2021		Dec. 31, 2020	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 3,040	$ 3,454	$ 2,790	$ 3,381

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2021 and 2020 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

6. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy, which includes SPS, has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits. The average annual interest crediting rates for these plans was 2.35 and 2.37 percent in 2021 and 2020, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

2020, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2021 and 2020 were $43 million and $43 million, respectively, of which $2 million was attributable to SPS in both years. In 2021 and 2020, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million and $6 million, respectively, of which immaterial amounts were attributable to SPS.

Xcel Energy, which includes SPS, investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as long-term projected return levels. 20 years or longer period, as well as long-term projected return levels. Xcel Energy and SPS continually review pension assumptions.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2021 were above the assumed level of 6.39%.
- Investment returns in 2020 were above the assumed level of 6.78%.
- In 2022, SPS's expected investment-return assumption is 6.39%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations consider many factors and generally result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, SPS' pension plan assets measured at fair value:

	Dec. 31, 2021 (a)					Dec. 31, 2020 (a)				
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**
Cash equivalents	$ 20	$ —	$ —	$ —	$ 20	$ 31	$ —	$ —	$ —	$ 31
Commingled funds	202	—	—	169	371	211	—	—	160	371
Debt securities	—	148	1	—	149	—	110	1	—	111
Equity securities	10	—	—	—	10	11	—	—	—	11
Other	—	2	—	5	7	2	1	—	—	3
Total	$ 232	$ 150	$ 1	$ 174	$ 557	$ 255	$ 111	$ 1	$ 160	$ 527

(a) See Note 5 for further information on fair value measurement inputs and methods.

For each of the fair value hierarchy levels, SPS' proportionate allocation of the total postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2021 (a)					Dec. 31, 2020 (a)				
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**
Cash equivalents	$ 3	$ —	$ —	$ —	$ 3	$ 3	$ —	$ —	$ —	$ 3
Insurance contracts	—	5	—	—	5	—	5	—	—	5
Commingled funds	6	—	—	7	13	7	—	—	7	14
Debt securities	—	22	—	—	22	—	22	—	—	22
Total	$ 9	$ 27	$ —	$ 7	$ 43	$ 10	$ 27	$ —	$ 7	$ 44

(a) See Note 5 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2021 or 2020.

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2020 to Dec. 31, 2021, due primarily to benefit payments and increases in discount rates used in actuarial valuations. Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for SPS are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2021**	**2020**	**2021**	**2020**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 562	$ 519	$ 38	$ 44
Service cost	11	10	1	1
Interest cost	15	18	1	1
Plan amendments	—	—	—	—
Actuarial (gain) loss	(13)	45	(3)	(5)
Plan participants' contributions	—	—	—	1
Benefit payments	(30)	(30)	(3)	(4)
Obligation at Dec. 31	$ 545	$ 562	$ 34	$ 38
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 527	$ 458	$ 44	$ 44
Actual return on plan assets	46	84	1	3
Employer contributions	14	15	—	—
Plan participants' contributions	—	—	1	1
Benefit payments	(30)	(30)	(3)	(4)
Fair value of plan assets at Dec. 31	$ 557	$ 527	$ 43	$ 44
Funded status of plans at Dec. 31	$ 12	$ (35)	$ 9	$ 6
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent assets	12	—	9	6
Noncurrent liabilities	—	(35)	—	—
Net amounts recognized	$ 12	$ (35)	$ 9	$ 6

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	**2021**	**2020**	**2021**	**2020**
Discount rate for year-end valuation	3.08	2.71	3.09	2.65
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	Pri-2012	Pri-2012	Pri-2012	Pri-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	5.30	5.50
Health care costs trend rate — initial: Post-65	N/A	N/A	4.90	5.00
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50	4.50
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50	4.50

Years until ultimate trend is reached	N/A	N/A	4	5

Accumulated benefit obligation for the pension plan was $506 million and $519 million as of Dec. 31, 2021 and 2020, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income (expense) in the statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2021	2020	2021	2020
Service cost	$ 11	$ 10	$ 1	$ 1
Interest cost	15	18	1	1
Expected return on plan assets	(30)	(29)	(2)	(2)
Amortization of prior service credit	—	—	—	—
Amortization of net loss	14	12	(1)	—
Settlement charge	—	—	—	—
Net periodic pension cost	10	11	(1)	—
Effects of regulation	—	2	—	—
Net benefit cost recognized for financial reporting	$ 10	$ 13	$ (1)	$ —
Significant Assumptions Used to Measure Costs:				
Discount rate	2.71 %	3.49 %	2.65 %	3.47 %
Expected average long-term increase in compensation level	3.75	3.75	—	—
Expected average long-term rate of return on assets	6.39	6.78	4.1	4.5

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2021	2020	2021	2020
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 143	$ 186	$ (19)	$ (18)
Prior service credit	(1)	(1)	(1)	(1)
Total	$ 142	$ 185	$ (20)	$ (19)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Noncurrent deferred debits	$ 142	$ 185	$ —	$ —
Noncurrent deferred credits	—	—	(20)	(19)
Total	$ 142	$ 185	$ (20)	$ (19)
Measurement date	Dec. 31, 2021	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2020

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2019 - 2022 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $50 million in January 2022, of which none was attributable to SPS.
- $131 million in 2021, of which $15 million was attributable to SPS.
- $150 million in 2020, of which $14 million was attributable to SPS.

For future years, Xcel Energy and SPS anticipate contributions will be made as necessary.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy's voluntary postretirement funding contributions were as follows:

- $9 million during 2022.
- $15 million during 2021.
- $11 million during 2020.
- Amounts attributable to SPS were immaterial.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Domestic and international equity securities	33 %	35 %	15 %	15 %
Long-duration fixed income securities	37	35	—	—
Short-to-intermediate fixed income securities	11	13	71	72
Alternative investments	17	15	8	9
Cash	2	2	6	4
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year

Plan Amendments — In 2020, there were no significant plan amendments made which affected the benefit obligation.

In 2021, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

Projected Benefit Payments

SPS' projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2022	$ 33	$ 3	$ —	$ 3
2023	31	3	—	2
2024	31	2	—	2
2025	32	2	—	2
2026	31	2	—	2
2027-2031	153	11	—	11

Defined Contribution Plans

Xcel Energy, which includes SPS, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for SPS was approximately $3 million in 2021 and 2020.

7. Commitments and Contingencies

Legal

SPS is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Legal fees are generally expensed as incurred.

Rate Matters

SPS is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the financial statements.

SPP Open Access Transmission Tariff (OATT) Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates. The timing of these refunds is uncertain.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. FERC has asked that this appeal be stayed until early 2022, in order to provide FERC with time to issue an order on SPS' April 2018 rehearing request. FERC's order is expected in the first quarter of 2022. The D.C. Circuit appeal may resume after that FERC order is issued.

Wind Operating Commitments — Public Utility Commission of Texas (PUCT) and New Mexico Public Regulation Commission (NMPRC) orders related to the Hale and Sagamore wind projects included certain operating and savings minimums. In general, annual generation must exceed a net capacity factor of 48%. If annual generation is below the guaranteed level, SPS would be obligated to refund an amount equal to foregone PTCs and fuel savings. Additionally, retail customer savings must exceed project costs included in base rates over the first ten years of operations. SPS would be required to refund excess costs, if any, after ten years of operations. As of Dec. 31, 2021, the full-year net capacity factor was 48.4%, resulting in no refund liability for 2021.

Contract Termination — SPS and Lubbock Power & Light (LP&L) have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the Electric Reliability Council of Texas (ERCOT) (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million (lump sum or annual installments), to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The settlement agreement is subject to approval by the PUCT and FERC.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for SPS, which are normally recovered through the regulated rate process.

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. SPS may sometimes pay all or a portion of the cost to remediate sites where past activities of SPS' predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs); and third-party sites, such as landfills, for which SPS is alleged to have sent wastes to that site.

Historical MGP, Landfill and Disposal Sites

SPS is remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities from final resolution of these issues; however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Federal Clean Water Act (CWA) Waters of the U.S. Rule — SPS is monitoring ongoing changes to the definition of Waters of the U.S. under the CWA. Regardless of which definition is applicable in the states in which we operate, SPS does not anticipate that compliance costs will be material.

Federal CWA Effluent Limitation Guidelines (ELG) — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. In October 2020, the EPA published a final rule revising the regulations. SPS anticipates that compliance costs will not be material and will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires sulfur dioxide (SO_2), nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes best available retrofit technology (BART) and reasonable further progress. Texas' first regional haze plan has undergone federal review.

All states are now subject to a second round of regional haze planning/rulemaking, focusing on additional reductions to meet reasonable progress requirements. Any additional impacts to SPS facilities are expected to be minimal.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the D.C. Circuit that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking. The EPA reaffirmed the rule in August 2020 with minor changes.

The 2020 EPA Action has been challenged. All pending actions could be consolidated and may proceed in the Fifth Circuit or the D.C. Circuit, where a parallel challenge has been filed. The timing of final decisions is unclear.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule referenced above are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule.

Implementation of the National Ambient Air Quality Standard (NAAQS) for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with one exception. The EPA issued final designations, which found the area near the Harrington plant as "unclassifiable." The area near the Harrington plant was monitored for the three years ending in 2019 and the monitoring showed the area to be exceeding the standard.

To address this issue, SPS negotiated an order with the Texas Commission on Environmental Quality (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.

SPS believes compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for SPS' assets.

SPS' AROs were as follows:

	2021		
(Millions of Dollars)	**Jan. 1, 2021**	**Accretion**	**Dec. 31, 2021** [(a)]
Electric			
Steam and other production	$ 52	$ 2	$ 54
Wind	50	2	52
Distribution	10	—	10
Total liability	$ 112	$ 4	$ 116

(a) There were no ARO amounts incurred, settled or revised in 2021.

	2020				
(Millions of Dollars)	**Jan. 1, 2020**	**Amounts Incurred** [(a)]	**Amounts Settled** [(b)]	**Accretion**	**Dec. 31, 2020** [(c)]
Electric					
Steam and other production	$ 51	$ —	$ (2)	$ 3	$ 52

Wind	16	33	—	1	50
Distribution	10	—	—	—	10
Total liability	$ 77	$ 33	$ (2)	$ 4	$ 112

(a) Amounts incurred related to the Sagamore wind farm placed in service in 2020.
(b) Amounts settled related to asbestos abatement projects.
(c) No AROs were revised in 2020.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of SPS' facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2021. Therefore, an ARO has not been recorded for these facilities.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent SPS' rights to use leased assets. In accordance with FERC requirements as provided in Docket No. AI19-1-000, starting in 2019, the present value of future operating lease payments is recognized in Account 227 and Account 243. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets in Account 101.1.

Most of SPS' leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the estimated incremental borrowing rate (weighted average of 4.4%). SPS has elected to utilize the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure. Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the balance sheet.

Operating lease ROU assets in Account 101.1:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
PPAs	$ 500	$ 500
Other	45	50
Gross operating lease ROU assets	545	550
Accumulated amortization	(82)	(58)
Net operating lease ROU assets	$ 463	$ 492

PPAs and Fuel Contracts

Non-Lease PPAs — SPS has entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2024, contain minimum energy purchase requirements.

Components of lease expense:

(Millions of Dollars)	2021	2020
Operating leases		
PPA capacity payments	$ 53	$ 48
Other operating leases (a)	4	3
Total operating lease expense (b)	$ 57	$ 51

(a) Includes short-term lease expense of $1 million for 2021 and 2020, respectively.
(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in operating expenses.

Commitments under operating leases as of Dec. 31, 2021 in Accounts 227 and 243:

(Millions of Dollars)	PPA (a) (b) Operating Leases	Other Operating Leases	Total Operating Leases
2022	$ 46	$ 3	$ 49
2023	46	3	49
2024	46	3	49
2025	46	4	50
2026	46	4	50
Thereafter	312	40	352
Total minimum obligation	542	57	599
Interest component of obligation	(120)	(15)	(135)
Present value of minimum obligation	422	42	464
Less current portion			(30)
Noncurrent operating and finance lease liabilities			$ 434
Weighted-average remaining lease term in years			12

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.
(b) PPA operating leases contractually expire at various dates through 2033.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts, were payments for capacity of $12 million, $12 million and $20 million in 2021, 2020 and 2019, respectively.

At Dec. 31, 2021, the estimated future payments for capacity that SPS is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity
2022	$ 12
2023	12
2024	6
2025	—
2026	—
Thereafter	—
Total	$ 30

Fuel Contracts — SPS has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal and natural gas requirements. These contracts expire between 2022 and 2033. SPS is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2021:

(Millions of Dollars)	Coal	Natural gas supply	Natural gas storage and transportation
2022	$ 211	$ 44	$ 32
2023	50	—	29
2024	31	—	16
2025	—	—	12
2026	—	—	6
Thereafter	—	—	14
Total	$ 292	$ 44	$ 109

8. Related Parties Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including SPS. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. SPS uses services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy, Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS have established a utility money pool arrangement.

See Note 5 for further information.

Significant affiliate transactions among the companies and related parties for the years ended Dec. 31:

(Millions of Dollars)	2021	2020
Operating expenses:		
Other operating expenses — paid to Xcel Energy Services Inc.	$ 209	$ 200

Accounts receivable and payable with affiliates at Dec. 31 were:

	2021		2020	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 2	$ —	$ 3	$ —
PSCo	7	—	6	—
Other subsidiaries of Xcel Energy Inc.	—	16	—	17
	$ 9	$ 16	$ 9	$ 17

9. Supplemental Cash Flow Data

(Millions of Dollars)	2021	2020
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (118)	$ (96)
Cash received for income taxes, net	21	10
Supplemental disclosure of non-cash investing transactions:		
Accrued property, plant and equipment additions	$ 37	$ 99
Inventory transfers to property, plant and equipment	6	31
Operating lease right-of-use assets	—	—
Allowances for funds used during construction	4	33

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(735,655)	(676,781)		(1,412,436)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				76,395	49,246		125,641		
3	Preceding Quarter/Year to Date Changes in Fair Value				(63,154)	(29)		(63,183)		
4	Total (lines 2 and 3)				13,241	49,217		62,458	294,786,100	294,848,558
5	Balance of Account 219 at End of Preceding Quarter/Year				(722,414)	(627,564)		(1,349,978)		
6	Balance of Account 219 at Beginning of Current Year				(722,414)	(627,564)		(1,349,978)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				76,281	49,233		125,514		
8	Current Quarter/Year to Date Changes in Fair Value				15,714	(155)		15,559		
9	Total (lines 7 and 8)				91,995	49,078		141,073	318,077,031	318,218,104
10	Balance of Account 219 at End of Current Quarter/Year				(630,419)	(578,486)		(1,208,905)		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	8,661,853,150	8,661,853,150					
4	Property Under Capital Leases	[(a)]463,485,261	422,838,070					40,647,191
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,707,296,161	1,707,296,161					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	10,832,634,572	10,791,987,381					40,647,191
9	Leased to Others							
10	Held for Future Use	4,167,109	4,167,109					
11	Construction Work in Progress	170,971,664	170,971,664					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	11,007,773,345	10,967,126,154					40,647,191
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,896,834,618	2,896,834,618					
15	Net Utility Plant (13 less 14)	8,110,938,727	8,070,291,536					40,647,191
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	2,696,442,067	2,696,442,067					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	200,392,551	[(b)]200,392,551					
22	Total in Service (18 thru 21)	2,896,834,618	2,896,834,618					
23	Leased to Others							

24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,896,834,618	2,896,834,618					

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.

Finance Lease Asset	$	—
Operating Right of Use Asset		470,652,148
Total	$	470,652,148

(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService

The amortization of other utility plant within account 111 includes the following:

Intangible Plant	$	165,411,689
Transmission		25,937,737
Steam Production		6,056,967
Distribution		2,085,322
General		900,161
Other Production		675
Total	$	200,392,551

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	247,106,854	28,522,031	5,142,007			270,486,878
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	247,106,854	28,522,031	5,142,007			270,486,878
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	17,078,045					17,078,045
9	(311) Structures and Improvements	247,387,560	4,213,103	575,955			251,024,708
10	(312) Boiler Plant Equipment	1,029,530,362	14,770,855	3,077,119			1,041,224,098
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	527,950,239	12,738,915	4,271,188		(1,983,922)	534,434,044
13	(315) Accessory Electric Equipment	89,092,628	5,847,867	267,964			94,672,531
14	(316) Misc. Power Plant Equipment	32,518,675	860,180	20,083			33,358,772
15	(317) Asset Retirement Costs for Steam Production	25,794,492	48,391				25,842,883
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,969,352,001	38,479,311	8,212,309		(1,983,922)	1,997,635,081
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						

20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights	1,069,775					1,069,775
38	(341) Structures and Improvements	125,120,432	9,674,345			24,921	134,819,698
39	(342) Fuel Holders, Products, and Accessories	6,193,387	7,668				6,201,055
40	(343) Prime Movers	56,279,704	131,909	858,605			55,553,008
41	(344) Generators	1,510,593,479	(512,319)	12,588,905		269,109	1,497,761,364
42	(345) Accessory Electric Equipment	98,271,706	11,618,333	62,897		13,960	109,841,102
43	(346) Misc. Power Plant Equipment	4,770,982	248,593				5,019,575
44	(347) Asset Retirement Costs for Other Production	49,157,323					49,157,323
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,851,456,788	21,168,529	13,510,407		307,990	1,859,422,900
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,820,808,789	59,647,840	21,722,716		(1,675,932)	3,857,057,981
47	3. Transmission Plant						
48	(350) Land and Land Rights	173,699,907	(5,033,506)				168,666,401
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	136,459,661	6,779,894	448,217		(248)	142,791,090

50	(353) Station Equipment	1,377,959,724	87,440,989	8,272,772		1,983,900	1,459,111,841
51	(354) Towers and Fixtures	8,216,055	41,995				8,258,050
52	(355) Poles and Fixtures	1,466,305,233	90,756,814	3,197,952			1,553,864,095
53	(356) Overhead Conductors and Devices	528,304,076	31,919,821	1,781,567			558,442,330
54	(357) Underground Conduit	275,004	3,816				278,820
55	(358) Underground Conductors and Devices	489,716					489,716
56	(359) Roads and Trails	517,736					517,736
57	(359.1) Asset Retirement Costs for Transmission Plant	25,029					25,029
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	[a]3,692,252,141	211,909,823	13,700,508		1,983,652	3,892,445,108
59	4. Distribution Plant						
60	(360) Land and Land Rights	26,479,954	4,256,623				30,736,577
61	(361) Structures and Improvements	43,898,539	8,540,938	137,458		(71,641)	52,230,378
62	(362) Station Equipment	333,200,777	16,144,936	1,900,517		56,208	347,501,404
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	383,714,919	60,519,629	2,290,105			441,944,443
65	(365) Overhead Conductors and Devices	304,209,190	30,767,053	4,785,299		15,434	330,206,378
66	(366) Underground Conduit	25,757,795	1,031,190	4,572			26,784,413
67	(367) Underground Conductors and Devices	51,311,073	3,235,848	127,188			54,419,733
68	(368) Line Transformers	240,233,483	14,362,379	1,539,801			253,056,061
69	(369) Services	99,403,164	8,066,132	281,436			107,187,860
70	(370) Meters	69,311,053	2,802,034	1,763,383			70,349,704
71	(371) Installations on Customer Premises	13,045,583					13,045,583
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	34,251,825	8,884,486	4,763,195			38,373,116
74	(374) Asset Retirement Costs for Distribution Plant	7,467,368					7,467,368
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,632,284,723	158,611,248	17,592,954		1	1,773,303,018
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82							

	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	3,106,328					3,106,328
87	(390) Structures and Improvements	96,812,526	1,103,153				97,915,679
88	(391) Office Furniture and Equipment	118,896,666	17,869,337	17,945,377			118,820,626
89	(392) Transportation Equipment	124,840,814	7,913,583	16,558,168			116,196,229
90	(393) Stores Equipment	430,924		8,150			422,774
91	(394) Tools, Shop and Garage Equipment	53,243,709	3,988,627			(307,989)	56,924,347
92	(395) Laboratory Equipment	10,928,506		18,876			10,909,630
93	(396) Power Operated Equipment	13,718,357					13,718,357
94	(397) Communication Equipment	134,148,765	20,946,585			270	155,095,620
95	(398) Miscellaneous Equipment	2,746,736					2,746,736
96	SUBTOTAL (Enter Total of lines 86 thru 95)	558,873,331	51,821,285	34,530,571		(307,719)	575,856,326
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	558,873,331	51,821,285	34,530,571		(307,719)	575,856,326
100	TOTAL (Accounts 101 and 106)	9,951,325,838	510,512,229	92,688,756			10,369,149,311
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	9,951,325,838	510,512,229	92,688,756			10,369,149,311

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionPlant

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	217,137	—	—	—	—	217,137
Account 352 - Structures & Improvements	2,623,037	(14,812)	—	—	—	2,608,225
Account 353 - Station Equipment	79,875,131	6,645,633	(617,058)	—	(22)	85,903,684
Account 355 - Poles & Fixtures	20,843,463	(364,133)	—	—	—	20,479,330
Account 356 - Overhead Conductors & Devices	11,631,229	(23,496)	—	—	—	11,607,733

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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46						
47	TOTAL					

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Electric Prod Other-TX-Gaines County	01/01/2015	12/31/2025	4,167,109
21	Other Property:			
22				
23				
24				
25				
26				
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44				
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46				
47	TOTAL			4,167,109

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Tolk 230kV Sub	15,781,243
2	Tolk T2 345/230 Xfmr Expansion	11,743,359
3	NIC0C-HW Rd. WW Trtment Improv	8,632,562
4	Roswell 115/69kV XFMR Upgrades	5,356,289
5	ITC-Purch DEMS HW SPS	5,245,151
6	Install Four Way Substation	5,215,269
7	HAR3C-Rpl Cooling Tower Structure	5,169,219
8	Plainview Renovation	4,923,413
9	DEMS Ph4 HW SPS-10756	4,912,108
10	CIP Substation Ph2 SW SPS -10659	3,500,734
11	Install Hopi XFR#2 SUB	3,174,098
12	Install New Centerport Substation	2,801,035
13	Harrington 230kV Bus Diffs	2,575,155
14	ITC ISO Intrfc & Stlmt Rpl SW SPS-2	2,301,499
15	GCT0C-Interconnect	2,244,043
16	CXT-My Acct SW SPS-10778	2,227,542
17	ADMS Data - SPS	1,670,817
18	TX-Dist Subs Tools and Equip	1,538,237
19	Lamb Co Intg 115kV SPE Relay UPGS T	1,473,011
20	Amherst Tap Rebuild Line	1,338,490
21	CXT-XE COM SW SPS-10779	1,316,333
22	CXT-Cust API SW Ph2-SPS	1,283,522
23	CXT-Mobile App PH1 SW SPS-10780	1,252,915
24	Crossroads 345kV Brkr Add	1,251,143
25	Install Medanos Fdr3	1,230,368

26	Synchrophasor SW SPS-10655		1,227,117
27	Littlefield West Tap Rebuild Line		1,198,127
28	Install Caveman SUB		1,156,610
29	ITC-Customer Care IVR Up SW 200162		1,125,110
30	PLX Emergent Fund -Steam prod		1,052,533
31	CXT-Cust Data SW Ph2-SPS		1,050,490
32	AGIS Meter Data Mgmt (MDM) SW SPS		1,047,514
33	Minor Projects		64,956,608
43	Total		170,971,664

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	2,496,673,135	2,496,673,135		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	303,401,608	303,401,608		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,987,233	2,987,233		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	8,033,568	8,033,568		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	314,422,409	314,422,409		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(87,546,749)	(87,546,749)		
13	Cost of Removal	(29,322,903)	(29,322,903)		
14	Salvage (Credit)	6,727,295	6,727,295		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(110,142,357)	(110,142,357)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(4,511,120)	[(a)](4,511,120)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	[(b)]2,696,442,067	[(c)]2,696,442,067		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,239,413,127	1,239,413,127		
21	Nuclear Production				
22	Hydraulic Production-Conventional				

23	Hydraulic Production-Pumped Storage				
24	Other Production	214,505,625	214,505,625		
25	Transmission	588,769,450	[(d)]588,769,450		
26	Distribution	403,654,371	403,654,371		
27	Regional Transmission and Market Operation				
28	General	250,099,494	250,099,494		
29	TOTAL (Enter Total of lines 20 thru 28)	[(e)]2,696,442,067	[(f)]2,696,442,067		

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Net change in RWIP	$	(3,986,449)
Net Transfers		(319,256)
(Gain)/Loss		(205,412)
Other		(3)
Total	$	(4,511,120)

(b) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

		"Non-Legal" ARO Balances
Steam Production	$	98,326,515
Other Production		4,384,994
Transmission		40,941,644
Distribution		45,265,087
General		1,132,798
Total	$	190,051,038

(c) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

NOTE: Amounts footnoted are based upon FERC ONLY RATES and EXCLUDES ASSET RETIREMENT COSTS (ARC).

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$ 2,651,213,816	$ 2,651,213,816	$ —	$ —
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	325,599,405	325,599,405		
4	(403.1) Depreciation Expense for Asset Retirement Costs	—	—		
5	(413) Exp of Elec Plt. Leas. To Others	—	—		
6	Transportation Expenses-Clearing	6,843,002	6,843,002		
7	Other Clearing Accounts	—	—		
8	Other Accounts (Specify, details in footnote):	—	—		
9					
10	Total Deprec. Prov for year (Enter Total of lines 3 thru 9)	332,442,407	332,442,407	—	—
11	Net Charges for Plant Retired				
12	Book Cost of Plant Retired	87,546,749	87,546,749		
13	Cost of Removal	29,322,903	29,322,903		
14	Salvage (Credit)	6,727,295	6,727,295		
15	Total Net Chrgs for Plant Ret. (Enter Total of lines 12 thru 14)	110,142,357	110,142,357		
16	Other Debit or Cr. Items (Describe, details in footnote):	(5,416,293)	(5,416,293)		
17					
18	Book Cost or Asset Retirement Costs Retired	$ —	$ —		
19	Balance End of Year (Enter Totals of lines 1,10,15,16 and 18)	$ 2,868,097,573	$ 2,868,097,573	$ —	$ —
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	$ 1,475,992,805	$ 1,475,992,805		
21	Nuclear Production	—	—		
22	Hydraulic Production-Conventional	—	—		
23	Hydraulic Production-Pumped Storage	—	—		
24	Other Production	227,561,398	227,561,398		
25	Transmission	507,905,442	507,905,442		
26	Distribution	401,451,759	401,451,759		

27	Regional Transmission and Market Operation	—	—		
28	General	255,186,169	255,186,169		
29	Total (Enter Total of lines 20 thru 28)	$ 2,868,097,573	$ 2,868,097,573	$ —	$ —

Net change in RWIP	$ (3,986,449)
Net Transfers and Adjustments	(1,224,426)
Gain/Loss	(205,412)
Other	(6)
Total	$ (5,416,293)
*Total agrees to line 16 in the schedule above.	
Transmission Serving Production Reserve	$ 21,798,250
*Footnote to line 25 in the schedule above.	

	"Non-Legal" ARO Balances
Steam Production	$ 229,008,717
Other Production	5,423,675
Transmission	(69,986,071)
Distribution	45,265,087
General	2,426,284
Total	$ 212,137,692

*Footnote to lines 20-28 in the schedule above.

(d) Concept: AccumulatedDepreciationTransmission

Transmission Serving Production	$ 19,685,058

(e) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

	"Non-Legal" ARO Balances
Steam Production	$ 98,326,515
Other Production	4,384,994
Transmission	40,941,644
Distribution	45,265,087
General	1,132,798
Total	$ 190,051,038

(f) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

NOTE: Amounts footnoted are based upon FERC ONLY RATES and EXCLUDES ASSET RETIREMENT COSTS (ARC).

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$ 2,651,213,816	$ 2,651,213,816	$ —	$ —
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	325,599,405	325,599,405		
4	(403.1) Depreciation Expense for Asset Retirement Costs	—	—		
5	(413) Exp of Elec Plt. Leas. To Others	—	—		
6	Transportation Expenses-Clearing	6,843,002	6,843,002		
7	Other Clearing Accounts	—	—		
8	Other Accounts (Specify, details in footnote):	—	—		
9					
10	Total Deprec. Prov for year (Enter Total of lines 3 thru 9)	332,442,407	332,442,407	—	—
11	Net Charges for Plant Retired				
12	Book Cost of Plant Retired	87,546,749	87,546,749		
13	Cost of Removal	29,322,903	29,322,903		
14	Salvage (Credit)	6,727,295	6,727,295		
15	Total Net Chrgs for Plant Ret. (Enter Total of lines 12 thru 14)	110,142,357	110,142,357		
16	Other Debit or Cr. Items (Describe, details in footnote):	(5,416,293)	(5,416,293)		
17					
18	Book Cost or Asset Retirement Costs Retired	$ —	$ —		
19	Balance End of Year (Enter Totals of lines 1,10,15,16 and 18)	$ 2,868,097,573	$ 2,868,097,573	$ —	$ —

Section B. Balances at End of Year According to Functional Classification

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
20	Steam Production	$ 1,475,992,805	$ 1,475,992,805		
21	Nuclear Production	—	—		
22	Hydraulic Production-Conventional	—	—		
23	Hydraulic Production-Pumped Storage	—	—		
24	Other Production	227,561,398	227,561,398		
25	Transmission	507,905,442	507,905,442		
26	Distribution	401,451,759	401,451,759		
27	Regional Transmission and Market Operation	—	—		
28	General	255,186,169	255,186,169		
29	Total (Enter Total of lines 20 thru 28)	$ 2,868,097,573	$ 2,868,097,573	$ —	$ —

Net change in RWIP	$ (3,986,449)
Net Transfers and Adjustments	(1,224,426)
Gain/Loss	(205,412)
Other	(6)
Total	$ (5,416,293)

*Total agrees to line 16 in the schedule above.

Transmission Serving Production Reserve	$ 21,798,250

*Footnote to line 25 in the schedule above.

	"Non-Legal" ARO Balances
Steam Production	$ 229,008,717
Other Production	5,423,675
Transmission	(69,986,071)
Distribution	45,265,087
General	2,426,284
Total	$ 212,137,692

*Footnote to lines 20-28 in the schedule above.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
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								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								
42	Total Cost of Account 123.1 $		Total					

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	9,329,532	21,738,911	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	[a]9,172,824	[b]10,208,868	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	11,485,157	11,537,008	Electric
8	Transmission Plant (Estimated)	692,372	1,007,778	Electric
9	Distribution Plant (Estimated)	302,219	393,695	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[c](76,723)	[d]97,351	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	21,575,849	23,244,700	
13	Merchandise (Account 155)	133,143	124,865	
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	31,038,524	45,108,476	

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Production	$	1,367,658
Transmission		3,596,898
Distribution		4,208,268
Total	$	9,172,824

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Production	$	1,233,454
Transmission		3,609,250
Distribution		5,366,164
Total	$	10,208,868

(c) Concept: PlantMaterialsAndOperatingSuppliesOther

Balance is comprised of miscellaneous inventory-related items (including purchase price variances, obsolescence and suspense items). Balance includes chemical inventory (ARKAY). Beginning balance of chemical inventory as of January 1 was $102,219 and ending balance as of December 31, 2020 is $125,763. Balance includes chemical inventory (Mercury Sorbent). Beginning balance of chemical inventory as of January 1 was $97,845 and ending balance as of December 31, 2020 is $123,629.

(d) Concept: PlantMaterialsAndOperatingSuppliesOther

Balance is comprised of miscellaneous inventory-related items (including purchase price variances, obsolescence and suspense items). Balance includes chemical inventory (ARKAY). Beginning balance of chemical inventory as of January 1 was $125,763 and ending balance as of December 31, 2021 is $238,693. Balance includes chemical inventory (Mercury Sorbent). Beginning balance of chemical inventory as of January 1 was $123,629 and ending balance as of December 31, 2021 is $146,655.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	[a]369,179		[c]82,997		[d]82,997		[e]82,997		[f]1,387,464		2,005,634	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									[g]53,364		53,364	
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	[b](39,251)										(39,251)	
19	Other:												
20	Allowances Used												

20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Beginning Balance Adjustment	1,175										1,175	
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	331,103		82,997		82,997		82,997		1,440,828		2,020,922	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	771		771		771		771		220,046		223,130	
37	Add: Withheld by EPA									1,542		1,542	
38	Deduct: Returned by EPA												
39	Cost of Sales	771								771		1,542	
40	Balance-End of Year			771		771		771		220,817		223,130	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	771	1							771	1	1,542	2
45	Gains		1								1		(b) 2
46	Losses												

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber

2020 and prior SO2 bank	286,182
2021 ARP	53,364
2021TX Only	29,633
	369,179
Beginning Balance Adjustment	1,175
	370,354

(b) Concept: ChargesToAllowancesInventoryNumber

ARP charges (includes NM units)	19,632
Federal Texas Only Program charges	19,619
	39,251

(c) Concept: AllowanceInventoryNumber

2022 Annual ARP allowances + 2022 TX Only SO2 Allowances: 82,997

(d) Concept: AllowanceInventoryNumber

2023 Annual ARP allowances + 2023 TX Only SO2 Allowances: 82,997

(e) Concept: AllowanceInventoryNumber

2024 Annual ARP allowances + 2024 TX Only SO2 Allowances: 82,997

(f) Concept: AllowanceInventoryNumber

Sum of all ARP Allowances years 2025 and forward to 2050: 1,387,464

(g) Concept: AllowancesIssuedLessWithheldAllowancesNumber

This is the ARP allocation added this year for 2051. No TX Only SO2 issued this year: 53,364

(h) Concept: AllowancesWithheldGainsFromAllowanceSales

Gain-Disposition of SO2 Allowances	$	18
SO2 Texas Retail Sharing		(10)
SO2 New Mexico Retail Sharing		(6)
	$	2

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

		Current Year		Year One		Year Two		Year Three		Future Years		Totals	
Line No.	NOx Allowances Inventory (Account 158.1) (a)	No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	[a]7,679		[e]4,012		[f]4,012		[g]4,012				19,715	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	[b]46										46	
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	[c]4,280										4,280	
19	Other:												
20	Allowances Used												

20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	[(d)]3,445		4,012		4,012		4,012				15,481	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber

2021 and prior bank (CSAPR & CSAPR Ozone)	3,635
Original Allocation for 2020 (CSAPR Ozone NOx)	4,044
	7,679

(b) Concept: AllowancesIssuedLessWithheldAllowancesNumber

Excess NUSA 2020 Seasonal NOx allowances issued in 2021	46
	46

(c) Concept: ChargesToAllowancesInventoryNumber

Seasonal Nox emissions for 2021	4,280
	4,280

(d) Concept: AllowanceInventoryNumber

CSAPR Annual Allowances Banked	2,724
2021 & Prior Vintage Ozone NOx Allowances Banked	721
	3,445

(e) Concept: AllowanceInventoryNumber

CSAPR Ozone NOx Group 2 2022 vintage: 4,012

(f) Concept: AllowanceInventoryNumber

CSAPR Ozone NOx Group 2 2023 vintage: 4,012

(g) Concept: AllowanceInventoryNumber

CSAPR Ozone NOx Group 2 2024 vintage: 4,012

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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						
20	TOTAL					

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						

46						
47						
48						
49	TOTAL					

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	XES-DPA-2020-Jul-1223-20730 WRB-Suth-115			43,382	242.0
3	XES-DPA-2020-Jul-1223-20730 WRB-Suth-115 Cost	5,281	561.6	5,281	561.6
4	DPA-2021-February-1279 Tumbleweed			4,946	242.0
5	DPA-2021-February-1279 Tumbleweed Cost	5,054	561.6	5,054	561.6
6	DPA-2021-February-1280 Hartmoore 600101749858			6,580	242.0
7	DPA-2021-February-1280 Hartmoore 600101749858 Cost	3,420	561.6	3,420	561.6
8	DPA-2021-February-1280 Hartmoore 600101754358			7,859	242.0
9	DPA-2021-February-1280 Hartmoore 600101754358 Cost	2,141	561.6	2,141	561.6
10	DPA-2021-June-1323-LCEC Waits			4,711	242.0
11	DPA-2021-June-1323-LCEC Waits Cost	289	561.6	289	561.6
12	DPA-2021-June-1324-LCEC Plains			4,711	242.0
13	DPA-2021-June-1324-LCEC Plains Cost	289	561.6	289	561.6
14	SPEC Leprino			10,000	242.0
15	RBEC First Street			15,000	242.0
20	Total				
21	**Generation Studies**				
22	Transmission Studies Total	16,474		113,663	
23	Generation Studies				
24	ASGI-2016-001(TX)-SPP 600101743862				242.0
25	GEN-2017-100(OK)-SPP 600101743864			(6,409)	242.0
26	GEN-2017-100(OK)-SPP 600101743864 Cost	2,757	561.7	2,757	561.7
27	GEN-2016-172(TX)-SPP 600101744361				242.0

28	GEN-2017-026(TX)-SPP 600101744363				242.0
29	GEN-2017-058(TX)-SPP 600101744365				242.0
30	GEN-2017-080(TX)-SPP 600101744368				242.0
31	ASGI-2017-007(TX)-SPP 600101744372				242.0
39	Total				
40	Grand Total				

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Southwestern Public Service Company	(1) ☐ An Original (2) ☑ A Resubmission	05/24/2022	End of: 2021/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Pension and Employee Benefit Obligations	185,773,457	12,700	Various	[a]42,875,621	[e]142,910,536
2	Pension and Employee Benefit Cap - Texas PUC Docket #47527	(755,308)	1,277,929	926	1,545,632	(1,023,011)
3	AFUDC in Plant - Amortized over plant life	41,986,944	160,778	283	1,163,094	40,984,628
4	Non-Nuclear Asset Retirement Obligations	32,579,957	7,536,143			40,116,100
5	Prior Flow Thru and Excess ADIT	28,350		254	28,350	
6	Texas Restructuring Meter - - A portion recovered in rates over 20 years - Texas PUC Docket #25088	52,348		407.3	34,898	17,450
7	Texas Revenue Surcharge Accrual - Docket #49831	69,892,801	436,477	407	50,354,867	19,974,411
8	RA Deferred Electric Fuel ST		456,498,807	557	310,413,163	146,085,644
9	Transmission Formula - Attachment O True-up	992,267	2,516,844	Various	[b]673,010	2,836,101
10	DSM New Mexico Concurrent - Case #19-00140-UT		13,200,653	Various	[c]13,200,653	
11	New Mexico RPS Rider - Various Amortizations - Case #1900134-UT	3,093,199	869,183		0	3,962,382
12	Power Purchased Contract Valuation Adjustments - Amortized over life of the contracts	405,775				405,775
13	DSM Texas Energy Efficiency - Docket #48324	1,068,830	6,917,617	Various	[d]5,382,030	2,604,417
14	Non-Plant ADIT	53,351,657	764,388	283	2,568,227	[f]51,547,818
15	RA Production Formula Rates	4,657,649	8,152,762	447	4,784,963	8,025,448
16	Texas Z2 Transmission - Docket #49831 - 5 Year Amortization	4,402,193				4,402,193
17	New Mexico Z2 Transmission - Case #17-00255-UT - 5 Year Amortization	1,425,564		407.3	520,489	905,075
18	COVID-19 Public Health Emergency	1,825,150	1,621,621			3,446,771
19	HB 4150	1,736,193	3,473,923			5,210,116
20	RA Fuel Recovery LT		3,559,184			3,559,184
44	TOTAL	402,517,026	506,999,009		433,544,997	475,971,038

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Account charged:		
926	$	(14,026,758)
228.3		(28,848,863)
	$	(42,875,621)

(b) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Account charged:		
421	$	(220)
456.1		(672,790)
	$	(673,010)

(c) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Account charged:		
908	$	(12,416,156)
456		(784,497)
	$	(13,200,653)

(d) Concept: OtherRegulatoryAssetsWrittenOffRecovered

Account charged:		
908	$	(4,313,198)
456		(1,068,832)
	$	(5,382,030)

(e) Concept: OtherRegulatoryAssets

Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — In September 2006, the FASB issued accounting guidance which requires companies to fully recognize the funded status of each pension and other postretirement benefit plan as a liability or asset on their balance sheets with all unrecognized amounts to be recorded in other comprehensive income. Xcel Energy applied regulatory accounting treatment, which allowed recognition of this item as a regulatory asset rather than as a charge to accumulated other comprehensive income.

Amounts have been recorded as follows based upon expected recovery in Rates:

Regulatory asset - Pension	$	142,485,253
Regulatory asset - Non-qualified pension		425,283
	$	142,910,536

(f) Concept: OtherRegulatoryAssets

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	$40,041,108	$11,506,710	$51,547,818
Total	$40,041,108	$11,506,710	$51,547,818 -

The Nonplant Excess Accumulated Deferred Income Taxes above include the following ungrossed amounts:

Bad Debts	$ 202,633
Demand Side Management	26,996
Deferred Compensation Plan Reserve	6,465
Employee Incentive	83,655
Environmental Remediation	2,607
Federal Net Operating Loss Benefit	39,184,970
Fuel Tax Credit - Income Addback	286
Inventory Reserve	10,672
Non-Qualified Pension Plan	13,233
Performance Recognition Awards	2,099
Performance Share Plan	2,094
Post Employment Benefits - FAS 106	380,138
Post Employment Benefits - FAS 112	21,207
State Tax Deduction	5,520
Texas Margin Tax	(18,697)
Vacation Accrual	117,230
Total Electric	$40,041,108

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS: Credits Account Charged (d)	CREDITS: Credits Amount (e)	Balance at End of Year (f)
1	Sharing Unrealized MTM Prop Margins		5,330,292	456	4,539,187	791,105
2	Debt Issuance Expense - Amortization over life of issued bonds		985,142	Various	[(a)]985,142	
3	Prepaid Retiree Medical	6,107,000	19,414	Various	[(b)]6,126,414	
4	Texas DSM Incentives	2,061,357	2,276,339	182	2,604,419	1,733,277
5	FIN 48/ASC740-10 Interest	486,288		232	486,288	
6	2017 TX Electric Rate Case -Docket No. 47527	346,832	22,189	928	369,021	
7	Prepaid Facility Fees	1,180,048		431	348,322	831,726
8	2020 TX Electric Fuel Formula	16,230	456,345			472,575
9	2020 TX Surcharge	632	147,974			148,606
10	SPS TX 2021 Retail Rate Case & Cost Deferrals -Docket No. 51802	520,500	67,120,406			67,640,906
11	Other Texas Dockets	283,646	26,075	928	21,930	287,791
12	2021 TX Surcharge		339,831			339,831
13	2021 TX Fuel Reconciliation		225,726			225,726
14	TX Elec 2021 AMS -Docket No. 52451		131,936			131,936
15	TX Elec 2021 LPL Credit		9,033			9,033
16	SPS TX 2019 Retail Rate Case & Cost Deferrals -Docket No. 49831	(19,034)	19,035			1
17	SPS NM 2018 E Supreme Court Case -Case No. 1700255-UT	1,128				1,128
18	SPS NM 2019 Retail Rate Case -Case No. 19-00170-UT	865,912		928	487,097	378,815
19	SPS NM 2021 Retail Rate Case	629,052	1,316,253			1,945,305
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	12,479,591				74,937,761

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInMiscellaneousDeferredExpense

Account charged:		
143	$	3,235
181		981,407
921		500
	$	985,142

(b) Concept: DecreaseInMiscellaneousDeferredExpense

Account charged:		
131	$	15,032
143		5,920
228.3		5,965,146
926		140,316
	$	6,126,414

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Unrecognized Tax Benefits	101,388	197,461
3	Electric Nonplant	232,437,166	398,949,303
4	Electric Plant	91,755,030	90,914,763
5	Regulatory Differences - Excess Deferred Plant Taxes	(27,719,263)	[a](26,802,678)
6	Regulatory Differences - Deferred ITC	15,005	
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	296,589,326	[b]463,258,849
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	(2)	1,662
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	296,589,324	463,260,511

Notes

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

The amortization of Excess ADIT included above in 410.1 is $1,076,527 for 2020 and $1,060,511 for 2021.

	2020 ARAM	2021 ARAM
Electric Distribution Plant	$ 449,938	$ 523,510
Electric General Plant	21,683	14,788
Electric Intangible Plant	356	308
Electric Production Plant	185,730	144,126
Electric Transmission Plant	418,830	377,779
Total ARAM	$ 1,076,537	$ 1,060,511

	12/31/2020	12/31/2021
Regulatory Difference - Effect of Rate Changes	$ (27,719,263)	$ (26,802,678)
	(27,719,263)	(26,802,678)
Regulatory Difference - ITC Grossup	15,005	—
Total Electric Plant Related Only	$ (27,704,258)	$ (26,802,678)

(b) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Electric Distribution Plant	$ 41,527,271	$ 41,422,728
Electric General Plant	962,660	962,926
Electric Production Plant	14,665,525	14,161,098
Electric Transmission Plant	34,295,171	33,987,455
Electric Transmission-Production Plant	304,403	380,556
Regulatory Difference - Excess Deferred Taxes	(27,719,263)	(26,802,678)
Regulatory Difference - Deferred ITC	15,005	—
TOTAL Electric Plant	$ 64,050,772	$ 64,112,085

The Excess ADIT above in column c include the ungrossed amounts presented below. These amounts will be amortized over the book lives of the underlying assets.

Excess (Electric only)	12/31/2021 Excess	12/31/2021 Gross up	12/31/2021 Total Regulatory
Flow Through	$ 248,075	$ 71,290	$ 319,365
Other Basis Differences (Unprotected)	(21,076,072)	(6,044,307)	(27,122,043)
Total	$ (20,827,997)	$ (5,973,017)	$ (26,802,678)

Accumulated Deferred Income Taxes (Account 190). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances on regulatory differences related to income taxes. An adjustment is made to include the regulatory asset balance related to nonplant accumulated deferred income taxes.

Schedule Page: 234 Line No.: 18 Column: c

Refer to FERC page 232 for SPS's regulatory asset related to nonplant excess ADIT.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2		200	1.00		100	100				
6	Total	200			100	100				
7	Preferred Stock (Account 204)									
8		10,000,000	1.00							
10	Total	10,000,000								
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2022-05-24	Year/Period of Report End of: 2021/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	2,436,497,706
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	301,103,955
16	Ending Balance Amount	2,737,601,661
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	2,737,601,661

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	9,033,435
22	TOTAL	9,033,435

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	3.70% Aug 15, 2047 First Mortgage Bonds		450,000,000		5,056,507		2,587,500	08/09/2017	08/15/2047	08/09/2017	08/15/2047	450,000,000	16,650,000
3	3.40% Aug 15, 2046 First Mortgage Bonds		300,000,000		3,511,006		507,000	08/12/2016	08/15/2046	08/12/2016	08/15/2046	300,000,000	10,200,000
4	4.40% Aug 15, 2048 First Mortgage Bonds		300,000,000		3,524,579		1,935,000	11/05/2018	11/15/2048	11/05/2018	11/15/2048	300,000,000	13,200,000
5	4.50% Aug 15, 2041 First Mortgage Bonds (1 of 3)		200,000,000		3,848,628		3,014,000	08/10/2011	08/15/2041	08/10/2011	08/15/2041	200,000,000	9,000,000
6	4.50% Aug 15, 2041 First Mortgage Bonds (2 of 3)		100,000,000		1,380,528	(10,058,000)		06/12/2012	08/15/2041	06/12/2012	08/15/2041	100,000,000	4,500,000
7	4.50% Aug 15, 2041 First Mortgage Bonds (3 of 3)		100,000,000		1,307,249		4,088,000	08/20/2013	08/15/2041	08/20/2013	08/15/2041	100,000,000	4,500,000
8	3.30% Jun 15, 2024 First Mortgage Bonds (1 of 2)		150,000,000		1,445,554		495,000	06/09/2014	06/15/2024	06/09/2014	06/15/2024	150,000,000	4,950,000
9	3.30% Jun 15, 2024 First Mortgage Bonds (2 of 2)		200,000,000		2,028,826	(596,000)		09/16/2015	06/15/2024	09/16/2015	06/15/2024	200,000,000	6,600,000
10	3.75% Jun 15, 2049 First Mortgage Bonds		300,000,000		3,622,206		3,783,000	06/18/2019	06/15/2049	06/18/2019	06/15/2049	300,000,000	11,250,000
11	3.15% May 01, 2050 First Mortgage Bonds (1 of 2)		350,000,000		4,230,333		3,017,000	05/18/2020	05/01/2050	05/18/2020	05/01/2050	350,000,000	11,025,000
12	(a) 3.15% May 01, 2050 First Mortgage Bonds (2 of 2)		250,000,000		3,130,907		245,000	03/02/2021	05/01/2050	03/02/2021	05/01/2050	250,000,000	6,540,625

13	Subtotal		2,700,000,000		33,086,323	(10,654,000)	19,671,500					2,700,000,000	98,415,625
14	Reacquired Bonds (Account 222)												
15													
16													
17													
18	Subtotal												
19	Advances from Associated Companies (Account 223)												
20													
21													
22													
23	Subtotal												
24	Other Long Term Debt (Account 224)												
25	6.00% Oct 1, 2033 Unsecured Series C and D Senior Notes		100,000,000		1,237,091		810,000	10/06/2003	10/01/2033	10/06/2003	10/01/2033	100,000,000	[b]6,063,181
26	6.00% Oct 1, 2036 Unsecured Series F Senior Notes		250,000,000		2,596,882		1,922,500	10/06/2006	10/01/2036	10/06/2006	10/01/2036	250,000,000	15,000,000
27	Interest on Debt to Associated Companies												[c]152,595
28	Subtotal		350,000,000		3,833,973		2,732,500					350,000,000	21,215,776
33	TOTAL		3,050,000,000									3,050,000,000	119,631,401

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

New Mexico Public Regulation Commission case no. 20-00236-UT. Order dated January 19, 2021

In March 2021, SPS issued $250,000,000 of 3.15 percent First Mortgage Bonds, due May 1, 2050. SPS used the net proceeds to finance or refinance, existing and future Eligible Green Expenditures.

(b) Concept: InterestExpenseOtherLongTermDebt

Interest at state rate	$	6,000,000
Interest at swap loss		63,181
	$	6,063,181

(c) Concept: InterestExpenseOtherLongTermDebt

Xcel Energy Services Inc.	$	125,782
Money Pool		26,813
	$	152,595

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	318,077,031
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		[a]13,805,027
6	Reconciling Items for the Year: Total Income Tax Expense	(59,466,733)
9	Deductions Recorded on Books Not Deducted for Return	
10		[b]772,395,534
14	Income Recorded on Books Not Included in Return	
15		[c](32,240,258)
19	Deductions on Return Not Charged Against Book Income	
20		[d](1,071,413,726)
27	Federal Tax Net Income	(58,843,125)
28	Show Computation of Tax:	
29	Federal Income Tax @ 21%	[e](12,357,056)
30	Other	1,614,647
31	TOTAL Net Federal Income Tax Accrual	(10,742,409)

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: TaxableIncomeNotReportedOnBooks

TAXABLE INCOME NOT REPORTED ON BOOKS:		
Gain/(Loss) on Disposition of Assets (Tax)	$	2,292,989
Provision for Contributions in Aid of Construction		11,512,038
	$	13,805,027

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:		
Avoided Cost Interest	$	3,458,615
Bad Debts		3,600,178
Book Depreciation Provision		328,627,113
Book Unamortized Cost of Reacquired Debt		841,559
Clearing Account Book Expense		6,910,974
Club Dues		29,000
Contributions Carryover		287,150
Deferred Compensation Plan Reserve		914,323
Employee Retention		9,046
Employee Stock Ownership Plan Dividends		525,318
Federal Net Operating Loss Benefit		336,078,485
Interest Income/Expense on Disputed Tax		258,236
Lobbying Expenses		714,000
Meals and Entertainment		217,000
Operating Lease Assets		28,169,838
Pension & Benefits Capitalized		1,468,551
Penalties		52,976
Performance Recognition Awards		9,918
Rate Refund Reserve		9,669,582
Recoverable Meters Provision		34,898
Regulatory Asset - Miscellaneous		46,964,956
Renewable Energy Standard/Credit		1,005,614
Section 174 - Section 59(e) Adjustment		2,427,871
Suite / Entertainment Tickets		6,000
Vacation Accrual		114,333
	$	772,395,534

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:		
Allowance for Funds During Construction (AFDC) - Equity	$	(4,057,886)
Deferred Revenue - Investment Tax Credit (ITC) Grant		(12,534)
Operating Lease Liabilities		(28,169,838)
	$	(32,240,258)

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:		
Allowable Depreciation	$	(703,219,883)
Allowance for Funds During Construction (AFDC) - Debt		(1,746,544)
Demand Side Management		(845,233)
Deferred Fuel Costs		(189,393,433)
Employee Incentive		(155,322)
Environmental Remediation		(2,456,504)
Executive Officer Non-deductible Compensation		(9,227)
Internally Developed Software		(78,000)
Inventory Reserve		(38,119)
Litigation Reserve		(100,000)
Mark-to-Market Adjustment		(1,329,035)
Non-Qualified Pension Plan		(92,647)
Payroll Tax Deferral		(2,460,273)
Pension Expense		(4,080,297)
Performance Share Plan		(203,039)
Post Employment Benefit - Long Term Disability		(113,503)
Post Employment Benefit - Retiree Medical		(1,042,146)
Rate Case / Restructuring		(68,936,754)
Regulatory Asset - Emergency Spec Response		(1,621,621)
Regulatory Asset / Liability - Transmission Attach O		(3,070,023)
Repair Expenditures		(48,500,000)
Section 174 Expenditures		(12,200,000)
State Tax Deduction		(854,963)
Tax Removal Cost Over Book		(28,867,160)
	$	(1,071,413,726)

(e) Concept: ComputationOfTax

Southwestern Public Service Company is a member of an affiliated group which will file a consolidated federal income tax return for the year 2021. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	$	(4,448,070)
Northern States Power Company (Minnesota) and Subsidiaries		(7,763,882)
Northern States Power Company (Wisconsin) and Subsidiaries		16,846,746
Public Service Company of Colorado and Subsidiaries		17,846,321
Nicollet Holdings Company, LLC and Subsidiaries		942,162
Nicollet Project Holdings LLC and Subsidiaries		(1,393,822)
Xcel Energy Communications Group Inc. and Subsidiaries		(19,387)
Xcel Energy Markets Holdings Inc. and Subsidiaries		309,449
Xcel Energy International Inc.		(998)
Xcel Energy Retail Holdings Inc. and Subsidiaries		(6,989)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries		(43,890)
Xcel Energy Ventures Inc. and Subsidiaries		92,528
Xcel Energy Venture Holdings, Inc. and Subsidiaries		173,514
Xcel Energy Wholesale Group Inc. and Subsidiaries		14,872
Xcel Energy WYCO Inc.		5,853,301
WestGas Interstate, Inc.		(6,228)
Xcel Energy Services Inc.		1,894,740

The consolidated federal income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated federal income tax liability among the companies based on the recognition of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Income	Federal Tax					(11,532,948)	(21,938,376)	(a)(10,405,428)			(11,892,750)			(k)359,802
2	Income Tax Adjustment	Federal Tax					790,539		(b)(790,539)			795,257			(l)(4,718)
3	FICA	Federal Tax		2020											
4	FICA	Federal Tax		2021	5,363,998		8,563,750	11,100,641		2,827,107		8,414,190			(m)149,559
5	Unemployment	Federal Tax		2020											
6	Unemployment	Federal Tax		2021	925		50,909	50,779		1,055		52,249			(1,340)
7	**Subtotal Federal Tax**				5,364,923		(2,127,750)	(10,786,956)	(11,195,967)	2,828,162		(2,631,054)			503,303
8	State Unemployment	State Tax	TX	2021	1,008		63,095	62,797		1,306		106,755			(43,661)
9	State Unemployment	State Tax	NM	2021	269		19,893	19,756		406		11,423			8,470
10	State Unemployment	State Tax	CO	2021	74		(74)					2,606			(2,681)
11	State Unemployment	State Tax	MI	2021	132		(132)					(76)			(56)
12	Income	State Tax	TX		1,752,148		(643,031)	566,802	(c)(209,415)	332,900		(643,031)			
13	Income Tax Adjustment	State Tax	TX				282,815		(d)(282,815)			282,815			
14	Property Tax	State Tax	TX	2020	35,028,776		(3,565,940)	31,462,836				(3,565,940)			
15	Property Tax	State Tax	TX	2021			49,668,000	20,265,598	(e)894,500	30,296,902		49,656,000			(n)12,000
16	Gross Receipts	State Tax	TX	2021			6,543,018	6,543,018				6,543,020			
17	Income	State Tax	NM				(139,960)	282,847	(f)427,942	5,135		(168,103)			(o)28,143

18	Income Tax Adjustment	State Tax	NM				174,673		[g](174,673)						[p]174,673
19	Property Tax	State Tax	NM	2020	5,721,332		(192,038)	5,529,294				(192,038)			
20	Property Tax	State Tax	NM	2021			15,408,000	4,599,472	[h]101,500	10,910,028		15,408,000			
21	Income	State Tax	OK				(52,821)		[i]52,821			(53,214)			[q]393
22	Income Tax Adjustment	State Tax	OK												
23	Franchise	State Tax	OK				20,000	20,000				20,000			
24	Property Tax	State Tax	OK	2020											
25	Property Tax	State Tax	OK	2021			616,473	616,467		6		616,473			
26	Income	State Tax	KS				(71,290)	5,314	[j]76,604			(71,634)			[r]344
27	Income Tax Adjustment	State Tax	KS												
28	Property Tax	State Tax	KS	2020											
29	Property Tax	State Tax	KS	2021			1,285,511	1,285,511				1,285,511			
30	**Subtotal State Tax**				42,503,739		69,416,192	71,259,712	886,464	41,546,683		69,238,567			177,625
31	Miscellaneous Tax	Other Taxes					(66,651)	(66,651)				(66,651)			
32	City Franchise Fees	Other Taxes			1,265,203		9,590,012	9,568,772	5,862	1,292,305		9,590,012			
33	Total SPS Use tax	Other Taxes			1,493,446		18,530,792	18,252,015		1,772,223		35,350			[s]18,495,442
34	**Subtotal Other Tax**				2,758,649		28,054,153	27,754,136	5,862	3,064,528		9,558,711			18,495,442
35	Total Property Tax														
36	Total Unemployment Tax														
37	Unemployment Tax 2														
38	Total Income Tax														
39	Total Fuel Tax														
40	Total Franchise Tax														
41	Total Other Federal Tax														
42	Total Other Property Tax														
43	Total Other Advalorem Tax														
44	Total Payroll Tax														
45	Total Advalorem Tax														
46	Total Severance Tax														
47	Total Other Taxes and Fees														
40	TOTAL				50,627,311		95,342,595	88,226,892	(10,303,641)	47,439,373		76,166,224			19,176,370

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: TaxAdjustments

Federal income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$	1,872,894
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)		(769,828)
Federal income tax benefit (accrual and cash) in other accounts receivable (143)		(11,508,494)
	$	(10,405,428)

(b) Concept: TaxAdjustments

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$	310,185
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		(1,100,724)
	$	(790,539)

(c) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)	$	(209,416)
Rounding		1
	$	(209,415)

(d) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$	(177,589)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		(105,226)
	$	(282,815)

(e) Concept: TaxAdjustments

Texas property tax on CWIP reclassified to a capital asset	$	894,500
	$	894,500

(f) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$	10,964
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)		3,832,002
State income tax benefit (accrual and cash) in other accounts receivable (143)		(3,415,025)
	$	427,941

(g) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$	(174,673)
	$	(174,673)

(h) Concept: TaxAdjustments

New Mexico property tax on CWIP reclassified to a capital asset	$	101,500
	$	101,500

(i) Concept: TaxAdjustments

State income tax benefit (accrual and cash) in other accounts receivable (143)	$	52,821
	$	52,821

(j) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$	770
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)		43,263
State income tax benefit (accrual and cash) in other accounts receivable (143)		32,571
	$	76,604

(k) Concept: TaxesIncurredOther

Federal non-operating income tax - non-utility (409.2)	$ 359,802
	$ 359,802

(l) Concept: TaxesIncurredOther

Federal non-operating income tax - non-utility (409.2)	$ (4,718)
	$ (4,718)

(m) Concept: TaxesIncurredOther

FICA taxes charged to capital, clearing and deferred accounts (107,184,186)	$ 99,060
FICA Payroll Taxes Non Utility (408.2)	11,048
TX State Unemployment Payroll Taxes Non Utility (408.2)	40
NM State Unemployment Payroll Taxes Non Utility (408.2)	144
	$ 110,292

(n) Concept: TaxesIncurredOther

Property Taxes - Non Utility (408.2)	$ 12,000
	$ 12,000

(o) Concept: TaxesIncurredOther

State non-operating income tax - non-utility (409.2)	$ 28,143
	$ 28,143

(p) Concept: TaxesIncurredOther

State non-operating income tax - non-utility (409.2) for uncertain tax positions (242)	$ 174,673
	$ 174,673

(q) Concept: TaxesIncurredOther

State non-operating income tax - non-utility (409.2)	$ 393
	$ 393

(r) Concept: TaxesIncurredOther

State non-operating income tax - non-utility (409.2)	$ 344
	$ 344

(s) Concept: TaxesIncurredOther

Use tax accrued on taxable materials and services	$ 18,495,442
	$ 18,495,442

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%									
6	Retail	52,443			411.4	52,413		30		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	52,443				52,413		30		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	52,443				52,413		30		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Comp Liabilities	5,005,445	Various	[a]113,537	1,027,860	5,919,768
2	Remediation & Other Deferred Costs	3,211,889	Various	[b]2,460,057		751,832
3	Executive PSP Long-Term	310,989	Various	[c]223,276	19,484	107,197
4	Long-term Income Tax and Interest Payable	4,546,551	Various	[d]2,035,058	1,257,970	3,769,463
5	Deferred Revenue - ITC Grant -25 year amortization beginning 2020 and ending 2035	181,744	417.1	12,534		169,210
6	Miscellaneous Deferred Credit	4,757,406	Various	[e]1,933,914	3,345,909	6,169,401
7	MTM Unrealized JOA to SPS from NSP	5,241,381	405	349,337	941,623	5,833,667
8	Deferred Revenue for Tax Liability for CIAC	537,929	456	537,929		
47	TOTAL	23,793,334		7,665,642	6,592,846	22,720,538

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInOtherDeferredCredits

Account charged:		
131	$	113,351
926		186
	$	113,537

(b) Concept: DecreaseInOtherDeferredCredits

Account charged:		
242	$	20,500
407.3		472,662
408.3		1,966,895
	$	2,460,057

(c) Concept: DecreaseInOtherDeferredCredits

Account charged:		
232	$	221,845
920		1,431
	$	223,276

(d) Concept: DecreaseInOtherDeferredCredits

Account charged:		
236	$	1,864,918
409.1		19,710
431		150,430
	$	2,035,058

(e) Concept: DecreaseInOtherDeferredCredits

Account charged:		
158.1	$	571,664
557		1,362,250
	$	1,933,914

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	1,073,958	(38,323)								[(a)]1,035,635
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	1,073,958	(38,323)								1,035,635
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	1,073,958	(38,323)								1,035,635
18	Classification of TOTAL										
19	Federal Income Tax	1,028,364	(36,696)								991,668
20	State Income Tax	45,594	(1,627)								43,967
21	Local Income Tax										

Page 272-273

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty
All amounts in columns b - k are related to Electric Steam Production Plant

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	1,308,140,744	89,892,782								1,398,033,526
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,308,140,744	89,892,782								1,398,033,526
6	Regulatory Difference - Prior	(532,054,329)					254	907,911	254	22,922,656	[(a)](510,039,584)
7	Regulatory Difference - AFUDC	41,986,944					182.3	1,177,180	182.3	174,864	40,984,628
9	TOTAL Account 282 (Total of Lines 5 thru 8)	818,073,359	89,892,782					2,085,091		23,097,520	[(b)]928,978,570
10	Classification of TOTAL										
11	Federal Income Tax	738,058,657	79,422,682					1,075,976		19,251,187	835,656,550
12	State Income Tax	80,014,702	10,470,100					1,009,115		3,846,333	93,322,020
13	Local Income Tax										

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

The amortization of Excess ADIT included above in 410.1 is $14,154,431 for 2020 and $14,986,804 for 2021.

	2020 ARAM	2021 ARAM
Electric Distribution Plant	$ 1,181,511	$ 1,887,137
Electric General Plant	2,495,214	1,850,245
Electric Intangible Plant	1,793,002	1,908,179
Electric Production Plant	6,441,486	6,690,403
Electric Transmission Plant	2,243,218	2,650,840
Total ARAM	$ 14,154,431	$ 14,986,804

The Excess ADIT above in column k include the ungrossed amounts presented below

Excess (Electric only)	12/31/2021 Excess	12/31/2021 Gross up	12/31/2021 Total Regulatory
Flow Through	$ 70,895	$ 20,373	$ 91,268
Method Life (Protected)	(329,301,175)	(94,632,076)	(423,933,251)
Other Basis Differences (Unprotected)	(66,956,227)	(19,241,373)	(86,197,600)
Total	$ (396,186,507)	$ (113,853,076)	$ (510,039,583)

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	12/31/2020	410.1 & Adjustments	12/31/2021
Electric Distribution Plant	$ 268,333,157	$ 3,033,882	$ 271,367,039
Electric General Plant	54,326,834	(1,097,742)	53,229,092
Electric Intangible Plant	1,437,433	1,035,706	2,473,139
Electric Production Plant	347,317,018	69,320,282	416,637,300
Electric Transmission Plant	631,821,181	15,815,069	647,636,250
Electric Transmission-Production Plant	1,854,175	1,795,502	3,649,677
Non-Utility	3,050,947	(9,919)	3,041,028
Regulatory Difference - Prior Flow Thru	(532,054,329)	22,014,747	(510,039,582)
Regulatory Difference - AFUDC Equity	41,986,944	(1,002,316)	40,984,628
TOTAL Electric Plant	$ 818,073,360	$ 110,905,211	$ 928,978,571

FERC Account	Description	Page No.	Plant-Related Ending Balance
282	Accumulated Deferred Income Taxes - Other Property	275	$ 928,978,571
	Less: Non-utility Accumulated Deferred Income Taxes		(3,041,028)
	Unblended ADIT Adjustment Total Company - Wholesale Jurisdiction		(40,851,107)
	Wholesale Jurisdiction Accumulated Deferred Income Taxes		$ 885,086,436
	Other items included in Plant-282 Balance:		
	Texas Gross Margin Tax		(16,707,928)
	Restructuring Meters		(451,167)

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Electric Non-Plant	178,917,496	58,258,524	22,441,047			254	2,568,226	254 & 219.1	764,388	212,931,135
4	Electric Plant	[(a)]21,794,862	(2,825,084)								18,969,778
9	TOTAL Electric (Total of lines 3 thru 8)	200,712,358	55,433,440	22,441,047				2,568,226		764,388	231,900,913
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other				77,137						77,137
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	200,712,358	55,433,440	22,441,047	77,137			2,568,226		764,388	231,978,050
20	Classification of TOTAL										
21	Federal Income Tax	186,783,839	50,580,054	21,618,802	71,352			2,521,915		703,562	213,998,090
22	State Income Tax	13,928,519	4,853,386	822,245	5,785			46,311		60,826	17,979,960
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

	12/31/2020	410.1	12/31/2021
Electric General Plant	$ 182,257	$ (14,771)	$ 167,486
Electric Intangible Plant	21,612,605	(2,810,314)	18,802,291
TOTAL Electric Plant	$ 21,794,862	$ (2,825,085)	$ 18,969,777

Refer to FERC page 278 for SPS's regulatory liability related to nonplant excess ADIT.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Deferred Investment Tax Credit	15,005	190	15,005		
2	Texas Fuel Costs Recovered via FCR	5,601,255	557	9,983,078	4,381,823	
3	New Mexico Fuel Costs - NMPRC - Rule 550 - Recovered via FPPCAC	29,771,590	557	61,571,598	31,800,008	
4	DSM Texas Energy Efficiency - Docket 49495	1,226,632	908	471,656	391,079	1,146,055
5	DSM NM Energy Efficiency - Case #19-00140-UT	3,046,457	908	136,674	1,220,670	4,130,453
6	Attachment 'O' Transmission Refund	7,778,822	456.1	6,435,795	8,750,691	10,093,718
7	2020 Production Formula True-up	250,610	447	445,209	271,923	77,324
8	Retiree Medical Liability	18,621,243	Various	[a]1,184,000	2,558,854	19,996,097
9	Sale of Lubbock Distribution Assets: - Incremental Capital Expenditures & Other - Amortized over the life of the asset - Docket #37901	2,314,560	407.4	53,949		2,260,611
10	SO2 Reserve - Docket #08-00354-UT	6				6
11	FAS 133-Elec Hedges	7,342,583	175	7,120,113	27,235,948	27,458,418
12	New Mexico RPS Rider - Case #19-00134-UT	3,438,803	Various	[b]18,251,143	21,536,795	6,724,455
13	Prior Flow Thru and Excess ADIT	504,363,415	Various	[c]21,124,847		483,238,568
14	Nonplant Excess ADIT	13,879,682	190	5,350,666	12,863	[d]8,541,879
15	LPL Departure Payment		456	14,291,596	24,015,131	9,723,535
41	TOTAL	597,650,663		146,435,329	122,175,785	573,391,119

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInOtherRegulatoryLiabilities

186	$	62,000
926		1,122,000
	$	1,184,000

(b) Concept: DecreaseInOtherRegulatoryLiabilities

Account charged:		
182.3	$	5,701,742
407.3		68,417
407.4		2,757,283
557		9,723,701
	$	18,251,143

(c) Concept: DecreaseInOtherRegulatoryLiabilities

182.3	$	28,350
282		21,096,497
	$	21,124,847

(d) Concept: OtherRegulatoryLiabilities

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	$6,635,127	$1,906,752	$8,541,879
Total	$6,635,127	$1,906,752	$8,541,879

The Nonplant Excess Accumulated Deferred Income Taxes above include the following ungrossed amounts:

Book Unamortized Cost of Reacquired Debt	$	726,474
Pension Expense		5,410,314
Rate Case / Restructuring Expense		462,373
Regulatory Asset - New Mexico Nitric Oxide (NOX)		898
State Tax Deduction		35,068
Total Electric	$	6,635,127

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Southwestern Public Service Company	(1) ☐ An Original (2) ☑ A Resubmission	05/24/2022	End of: 2021/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	[a]417,188,372	[e]370,349,376	3,608,168	3,786,587	315,480	312,655
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	398,712,031	337,108,261	4,913,365	4,819,471	78,131	77,741
5	Large (or Ind.) (See Instr. 4)	[b]537,033,279	[f]417,655,591	11,827,687	11,452,144	273	268
6	(444) Public Street and Highway Lighting	8,299,139	7,021,431	27,489	36,980	110	112
7	(445) Other Sales to Public Authorities	35,591,922	31,354,183	483,208	479,075	6,215	6,214
8	(446) Sales to Railroads and Railways	0					
9	(448) Interdepartmental Sales	0					
10	TOTAL Sales to Ultimate Consumers	1,396,824,743	1,163,488,842	20,859,917	20,574,257	400,209	396,990
11	(447) Sales for Resale	643,062,096	288,053,747	8,355,555	8,612,293	5	7
12	TOTAL Sales of Electricity	2,039,886,839	1,451,542,589	29,215,472	29,186,550	400,214	396,997
13	(Less) (449.1) Provision for Rate Refunds	0	(3,874,352)			0	
14	TOTAL Revenues Before Prov. for Refunds	2,039,886,839	1,455,416,941	29,215,472	29,186,550	400,214	396,997
15	Other Operating Revenues						
16	(450) Forfeited Discounts	1,919,056	1,570,792				
17	(451) Miscellaneous Service Revenues	[c]698,666	[g]580,943				
18	(453) Sales of Water and Water Power	0					

19	(454) Rent from Electric Property	8,750,806	8,863,332				
20	(455) Interdepartmental Rents	0					
21	(456) Other Electric Revenues	[d](58,150,351)	(6,023,271)				
22	(456.1) Revenues from Transmission of Electricity of Others	287,393,567	273,508,409				
23	(457.1) Regional Control Service Revenues	0					
24	(457.2) Miscellaneous Revenues	0					
25	Other Miscellaneous Operating Revenues						
25.1		0					
26	TOTAL Other Operating Revenues	240,611,744	278,500,205				
27	TOTAL Electric Operating Revenues	2,280,498,583	1,733,917,146				

Line12, column (b) includes $ of unbilled revenues.
Line12, column (d) includes MWH relating to unbilled revenues

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ResidentialSales

		Current Year Billed Revenue	Current Year Unbilled Revenue	Current Year Total
Residential	440	$ 417,282,982	$ (94,610)	$ 417,188,372
Small C&I	442	397,541,461	1,170,570	398,712,031
Large C&I	442	527,530,635	9,502,644	537,033,279
PSHL	444	8,209,299	89,840	8,299,139
OSPA	445	35,480,078	111,844	35,591,922
Resale	447	308,972,650	334,089,446	643,062,096
		$ 1,695,017,105	$ 344,869,734	$ 2,039,886,839

This note applies to Page 300 column (b) rows 2,4,5,6,7, and 11

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Commercial and industrial sales are classified as "large" for purposes of this report if the customer has a minimum registered demand of 1,000 KW or more.

(c) Concept: MiscellaneousServiceRevenues

Account charged:

	Current Year
Customer Connections	$ 444,050
Return Check Charge	151,173
Other	103,443
	$ 698,666

	Previous Year
Customer Connections	$ 281,521
Return Check Charge	197,976
Other	101,445
	$ 580,942

(d) Concept: OtherElectricRevenue

	Current Year
Deferred Fuel Revenue	$ 35,372,846
JOA Margin Sharing	13,563,310
Distrib Service Charge - Coops - Whl	1,306,949
EEI Mutual Aid Revenue	509,810
TOIF Annual Assessment	(1,192)
Sales tax return adj	64,903
CIP/DSM Incentive	82,226
PTC Sharing	(104,092,333)
Misc Other	(4,956,869)
	$ (58,150,351)

	Previous Year
Deferred Fuel Revenue	$ 46,274,930
JOA Margin Sharing	3,439,406
CIP/DSM Incentive	1,429,290
Mutual Aid	885,103
Distrib Service Charge-Coops-Whl	414,642
PTC's	(58,724,644)
MISC Other	258,002
	$ (6,023,271)

Other Revenue includes the effect of sharing electric trading margins with affiliates Public Service Company of Colorado and Northern States Power Co. (a Minnesota Company).

(e) Concept: ResidentialSales

		Previous Year		
		Billed Revenue	Unbilled Revenue	Total
Residential	440	$ 368,909,709	$ 1,439,667	$ 370,349,376
Small C&I	442	336,594,157	514,104	337,108,261
Large C&I	442	419,888,248	(2,232,657)	417,655,591
PSHL	444	6,964,014	57,417	7,021,431
OSPA	445	31,514,001	(159,818)	31,354,183
Resale	447	248,700,800	39,352,947	288,053,747
		$ 1,412,570,929	$ 38,971,660	$ 1,451,542,589

This note applies to Page 300 column (c) rows 2,4,5,6,7, and 11

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Commercial and industrial sales are classified as "large" for purposes of this report if the customer has a minimum registered demand of 1,000 KW or more.

(g) Concept: MiscellaneousServiceRevenues

Account charged:

	Current Year
Customer Connections	$ 444,050
Return Check Charge	151,173
Other	103,443
	$ 698,666

	Previous Year
Customer Connections	$ 281,521
Return Check Charge	197,976
Other	101,445
	$ 580,942

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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2					
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45					
46	TOTAL				0

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	TX Res Lighting	5,852	1,550,901	8,043	728	0.2245
2	TX Res Space Heat	(8)	(445)			0.0349
3	TX Residential	2,471,001	292,996,514	208,902	11,829	0.1010
4	TX Res Time of Use	685	79,776	45	15,222	0.0987
5	NM Res Lighting	4,901	1,146,811	6,223	788	0.1981
6	NM Res Space Heat	471,372	45,735,216	29,733	15,853	0.0795
7	NM Residential	669,648	75,761,683	62,524	10,710	0.0947
8	NM Res Time of Use	178	12,525	10	17,800	0.0616
41	TOTAL Billed Residential Sales	3,623,629	417,282,981	315,480	72,930	0.8930
42	TOTAL Unbilled Rev. (See Instr. 6)	(15,461)	(94,609)			
43	TOTAL	3,608,168	[a]417,188,372	315,480		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ResidentialSales

		Current Year		
		Billed Revenue	Unbilled Revenue	Total
Residential	440	$ 417,282,982	$ (94,610)	$ 417,188,372
Small C&I	442	397,541,461	1,170,570	398,712,031
Large C&I	442	527,530,635	9,502,644	537,033,279
PSHL	444	8,209,299	89,840	8,299,139
OSPA	445	35,480,078	111,844	35,591,922
Resale	447	308,972,650	334,089,446	643,062,096
		$ 1,695,017,105	$ 344,869,734	$ 2,039,886,839

This note applies to Page 300 column (b) rows 2,4,5,6,7, and 11

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
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41	TOTAL Billed Small or Commercial			0	0	0
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	4,913,365	398,712,031	78,131		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Large (or Ind.) Sales					
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	11,827,687	[(a)]537,033,279	273		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Commercial and industrial sales are classified as "large" for purposes of this report if the customer has a minimum registered demand of 1,000 KW or more.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	NM Commercial Area Lighting	9,961	1,488,166	2,715	3,669	0.1494
2	TX Flood Lighting	11,298	1,413,455	1,178	9,591	0.1251
3	TX Guard Lighting	6,500	1,735,830	4,350	1,494	0.2671
4	NM General Service Time of Use	168	29,748	1	168,000	0.1771
5	TX General Serv Secondary Low Load	1,363	322,643	1	1,363,000	0.2367
6	TX Gen Svc Experimental TOU	50,429	3,594,738	41	1,229,976	0.0713
7	NM Irrigation	72,423	6,836,159	1,009	71,777	0.0944
8	NM Large Gen Serv Trans - 115 kV	2,997,698	141,748,917	31	96,699,935	0.0470
9	TX Large Gen Serv Trans - 115 kV	4,858,087	182,283,909	52	93,424,750	0.0375
10	NM Large Gen Serv Trans - 69 kV	144,007	7,511,998	6	28,801,400	0.0522
11	TX Large Gen Serv Subtran - 69 kV	565,734	22,189,461	11	51,430,364	0.0392
12	NM Primary General	1,890,089	125,786,101	585	3,236,454	0.0659
13	NM Primary General Oil Well Pumping	522,898	44,638,508	4,393	119,030	0.0850
14	TX Primary General	1,305,609	69,494,251	509	2,565,047	0.0532
15	TX Primary General Oil Well Pumping	329,968	20,461,247	2,919	113,041	0.0620
16	TX Primary Qualifying Fac	1	25,944	0		25.9440
17	SAS-12 WRB Refining	504,823	19,690,769	1	504,823,000	0.0390
18	SAS-4 Canadian River Water Auth	136,927	5,652,510	1	136,927,000	0.0413
19	NM Secondary General	692,697	62,245,058	4,198	165,006	0.0899
20	NM Small General Service	143,188	14,468,916	11,928	12,004	0.1010
21	TX Small General Service	275,268	28,838,822	32,363	8,505	0.1048
22	TX Secondary General	2,015,083	157,668,966	12,112	166,371	0.0782
23	TX Trans QF Standby - 115kV	113,944	6,320,550	0		0.0555

24	TX Trans QF Standby - 69kV	780	625,430	0		0.8018
41	TOTAL Billed Commercial and Industrial Sales	16,648,943	925,072,096	78,404	921,339,414	29
42	TOTAL Unbilled Rev. (See Instr. 6)	92,109	10,673,214			
43	TOTAL	16,741,052	935,745,310			

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	TX SA-810 Street and Hwy Ltg	62	8,957	3	20,667	0.1445
2	TX SA-805 Amarillo Hwy Ltg	107	6,302	2	53,500	0.0589
3	TX Street Ltg Restricted Outdoor	20,596	5,872,265	87	234,045	0.2851
4	NM Street Lighting	7,493	2,321,775	18	416,278	0.3099
41	TOTAL Billed Public Street and Highway Lighting	28,258	8,209,299	110	724,490	0.7984
42	TOTAL Unbilled Rev. (See Instr. 6)	(769)	89,840			
43	TOTAL	27,489	8,299,139	110		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Other Sales to Public Authorities	484,162	35,480,078	6,215	651,848	0.4001
42	TOTAL Unbilled Rev. (See Instr. 6)	(954)	111,844			
43	TOTAL	483,208	35,591,922	6,215		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Sales To Railroads and Railways					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		0			

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Interdepartmental Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		0			

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		0	0		

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	20,784,992	1,386,044,454	400,209	922,788,682	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	74,925	10,780,289			
43	TOTAL - All Accounts	20,859,917	[a]1,396,824,743	400,209	922,788,682	

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesIncludingUnbilledRevenue

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:	
NM Commercial Area Lighting	$ 228,266
NM General Service Time of Use	3,907
NM Irrigation	1,708,396
NM Large Gen Serv Trans - 115 kV	63,471,781
NM Large Gen Serv Trans - 69 kV	2,994,061
NM Large Municipal & School	2,711,987
NM Primary General	43,690,652
NM Primary General Oil Well Pumping	12,068,364
NM Res Lighting	113,706
NM Res Space Heat	10,584,738
NM Res Time of Use	4,079
NM Residential	15,295,643
NM Secondary General	16,021,836
NM Small General Service	3,299,949
NM Small Municipal & School	237,606
NM Street Lighting	167,785
SAS-12 WRB Refining	6,617,106
SAS-4 Canadian River Water Auth	1,921,349
SAS-8 Orion	-
TX Flood Lighting	161,573
TX Gen Svc Experimental TOU	724,228
TX General Serv Secondary Low Load	19,046
TX Guard Lighting	92,987
TX Large Gen Serv Subtran - 69 kV	7,422,853
TX Large Gen Serv Trans - 115 kV	63,294,121
TX Large Municipal	2,596,548
TX Large School	2,193,441
TX Primary General	22,943,260
TX Primary General Oil Well Pumping	-
TX Res Lighting	83,674
TX Res Space Heat	(89)
TX Res Time of Use	9,807
TX Residential	35,389,672
TX SA-805 Amarillo Hwy Ltg	292,756
TX SA-810 Street and Hwy Ltg	1,528
TX Secondary General	28,900,718
TX Small General Service	3,946,438
TX Small Municipal & School	292,987
TX Street Ltg Restricted Outdoor	877
TX Trans QF Standby - 115kV	1,467,866
TX Trans QF Standby - 69kV	-
Total	$ 350,975,502

Included in the total commercial and industrial revenue amount is $2,288,376 charged on several New Mexico premises for failing to purchase a contractually set minimum amount of energy. These contracts are instituted in order to ensure appropriate recovery in cases where SPS must construct significant infrastructure to serve a specific load request.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	Central Valley Elec Cooperative, Inc.	RQ	RS114	65	120	100	513,350	5,912,974	27,567,400	(b) 8,247,534	41,727,908
2	Farmers' Elec Cooperative Inc., of NM	RQ	RS115	41	69	52	214,642	4,266,769	12,051,019	(c) 4,693,405	21,011,193
3	Lea County Elec Cooperative, Inc.	RQ	RS116	110	188	143	668,789	10,129,184	36,095,120	(d) 12,964,981	59,189,285
4	Roosevelt County Elec Cooperative, Inc.	RQ	RS117	17	31	24	101,746	1,411,895	5,859,549	(e) 2,036,156	9,307,600
5	Tri-County Elec Cooperative	RQ	RS136	0	0	0	0	(47,315)	467,253	(f) (629,735)	(209,797)
6	West Texas Municipal Power Agency	RQ	RS137				0			(g) 0	
7	Lubbock Power and Light	RQ	RS138	173			495,679	16,390,750	32,975,530	(h) 29,874,173	79,240,453

8	Golden Spread Electric	RQ	RS135								
9	Lubbock Power and Light	OS	RS3				1,686,909	4,800,000	189,948,309	[a]0	194,748,309
10	Southwest Power Pool	[a] OS	V3				4,674,440		222,585,474	[a]15,461,671	238,047,145
11	Golden Spread Electric	OS	RS135								
15	Subtotal - RQ						1,994,206	38,064,257	115,015,871	57,186,514	210,266,642
16	Subtotal-Non-RQ						6,361,349	4,800,000	412,533,783	15,461,671	432,795,454
17	Total						8,355,555	42,864,257	527,549,654	72,648,185	643,062,096

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

SPP Market Transactions

(b) Concept: OtherChargesRevenueSalesForResale

Customer Charges, Margin Credits, Transmission, Annual Formula True Up Estimates

(c) Concept: OtherChargesRevenueSalesForResale

Customer Charges, Margin Credits, Transmission, Annual Formula True Up Estimates

(d) Concept: OtherChargesRevenueSalesForResale

Customer Charges, Margin Credits, Transmission, Annual Formula True Up Estimates

(e) Concept: OtherChargesRevenueSalesForResale

Customer Charges, Margin Credits, Transmission, Annual Formula True Up Estimates

(f) Concept: OtherChargesRevenueSalesForResale

Customer Charges, Margin Credits, Transmission, Annual Formula True Up Estimates

(g) Concept: OtherChargesRevenueSalesForResale

WTMPA contract was terminated in April 2019 and LP&L contract executed to replace this contract.

(h) Concept: OtherChargesRevenueSalesForResale

Customer Charges, Margin Credits, Transmission, Annual Formula True Up Estimates

(i) Concept: OtherChargesRevenueSalesForResale

LP&L has two contracts. There is a partial contract as well as a bridge contract. The total load volume per the contracts is a total of 170 MV per month, as such we are not calculating average amounts for this counterparty.
contract.

(j) Concept: OtherChargesRevenueSalesForResale

Transmission and Trading Revenues

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	3,600,433	3,681,076
5	(501) Fuel	[a]376,820,788	[e]212,901,831
6	(502) Steam Expenses	12,168,224	11,497,141
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	9,145,309	9,124,200
10	(506) Miscellaneous Steam Power Expenses	13,644,470	12,774,763
11	(507) Rents	2,809,759	3,473,755
12	(509) Allowances	0	[f]34,908
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	418,188,983	253,487,674
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	679,200	579,335
16	(511) Maintenance of Structures	3,872,486	3,853,877
17	(512) Maintenance of Boiler Plant	11,963,829	13,623,550
18	(513) Maintenance of Electric Plant	9,826,648	6,882,938
19	(514) Maintenance of Miscellaneous Steam Plant	8,630,899	9,740,705
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	34,973,062	34,680,405
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	453,162,045	288,168,079
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		

26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		

58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	663,882	539,801
63	(547) Fuel	59,891,481	25,168,466
64	(548) Generation Expenses	464,087	297,132
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	3,063,968	5,097,015
66	(550) Rents	5,436,503	2,320,882
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	69,519,921	33,423,296
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	803,593	465,298
70	(552) Maintenance of Structures	4,911,008	229,953
71	(553) Maintenance of Generating and Electric Plant	1,910,731	1,306,723
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,064,754	3,702,636
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	9,690,086	5,704,610
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	79,210,007	39,127,906
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	[b]795,215,680	[g]392,299,303
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	905,526	1,068,702
78	(557) Other Expenses	[c](213,804,174)	[h](48,340,730)
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	582,317,032	345,027,275
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,114,689,084	672,323,260
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,376,922	8,070,232
85	(561.1) Load Dispatch-Reliability	1,447	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,460,977	3,250,020
87	(561.3) Load Dispatch-Transmission Service and Scheduling		

88	(561.4) Scheduling, System Control and Dispatch Services	3,660,351	4,883,414
89	(561.5) Reliability, Planning and Standards Development	359	15,052
90	(561.6) Transmission Service Studies	104,423	15,239
91	(561.7) Generation Interconnection Studies	109,094	133,123
92	(561.8) Reliability, Planning and Standards Development Services	2,766,134	3,356,263
93	(562) Station Expenses	1,356,458	1,479,781
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	850,620	421,300
95	(564) Underground Lines Expenses	369	
96	(565) Transmission of Electricity by Others	175,994,020	178,025,516
97	(566) Miscellaneous Transmission Expenses	4,401,798	3,377,111
98	(567) Rents	1,668,125	1,812,941
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	201,751,097	204,839,992
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	3,052	
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,714,568	1,563,057
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	862,996	451,741
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	2,580,616	2,014,798
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	204,331,713	206,854,790
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	157,960	162,307
116	(575.2) Day-Ahead and Real-Time Market Facilitation	323,540	299,544
117	(575.3) Transmission Rights Market Facilitation		

118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	8,065	14,398
120	(575.6) Market Monitoring and Compliance	22,870	24,982
121	(575.7) Market Facilitation, Monitoring and Compliance Services	8,235,256	8,240,761
122	(575.8) Rents	35,146	40,700
123	Total Operation (Lines 115 thru 122)	8,782,837	8,782,692
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	8,782,837	8,782,692
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	5,199,110	4,895,764
135	(581) Load Dispatching	441,586	344,092
136	(582) Station Expenses	1,127,990	987,962
137	(583) Overhead Line Expenses	522,722	1,024,119
138	(584) Underground Line Expenses	1,201,935	826,244
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	534,596	566,972
140	(586) Meter Expenses	2,251,159	2,003,621
141	(587) Customer Installations Expenses	559,704	587,493
142	(588) Miscellaneous Expenses	6,673,937	8,402,872
143	(589) Rents	2,302,097	2,720,861
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	20,814,836	22,360,000
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	19,330	27,038
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	629,559	706,231

148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	8,165,333	8,226,654
150	(594) Maintenance of Underground Lines	23,155	52,743
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems	229,443	314,445
153	(597) Maintenance of Meters	90,903	57,128
154	(598) Maintenance of Miscellaneous Distribution Plant	2,190	14,441
155	TOTAL Maintenance (Total of Lines 146 thru 154)	9,159,913	9,398,680
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	29,974,749	31,758,680
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	35,763	29,648
160	(902) Meter Reading Expenses	5,325,327	4,965,640
161	(903) Customer Records and Collection Expenses	9,132,732	7,208,292
162	(904) Uncollectible Accounts	7,152,020	(i) 4,408,504
163	(905) Miscellaneous Customer Accounts Expenses	108,226	181,034
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	21,754,068	16,793,118
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	19,217,344	18,354,562
169	(909) Informational and Instructional Expenses	335,040	291,929
170	(910) Miscellaneous Customer Service and Informational Expenses	62,291	109,341
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	19,614,675	18,755,832
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	313,554	300,638
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	5,998	11,057
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	319,552	311,695
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		

180	Operation		
181	(920) Administrative and General Salaries	35,415,902	39,987,946
182	(921) Office Supplies and Expenses	22,475,308	20,604,458
183	(Less) (922) Administrative Expenses Transferred-Credit	24,313,407	23,632,717
184	(923) Outside Services Employed	7,421,204	6,387,835
185	(924) Property Insurance	6,376,140	3,855,270
186	(925) Injuries and Damages	5,491,093	7,676,830
187	(926) Employee Pensions and Benefits	[a]28,763,243	[b]29,190,662
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	5,882,647	12,051,715
190	(929) (Less) Duplicate Charges-Cr.	1,278,681	1,137,629
191	(930.1) General Advertising Expenses	1,200,875	1,270,941
192	(930.2) Miscellaneous General Expenses	1,567,818	1,212,301
193	(931) Rents	17,416,568	14,119,038
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	106,418,710	111,586,650
195	Maintenance		
196	(935) Maintenance of General Plant	472,576	50,393
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	106,891,286	111,637,043
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,506,357,964	1,067,217,110

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: FuelSteamPowerGeneration

FERC 501 - Fuel includes $1,401,259.01 of ancillary service cost reclassed to gen book trading cost.

(b) Concept: PurchasedPower

FERC 555 - Purchased Power includes $36,011 of ancillary service cost reclassed to gen book trading cost.

(c) Concept: OtherExpensesOtherPowerSupplyExpenses

The total of this account includes deferred expenses related to Fuel and Renewable Energy Costs as follows:

Fuel	$	(222,607,586)
RECs and other renewable energy costs	$	6,354,636

(d) Concept: EmployeePensionsAndBenefits

Texas PUC Docket No. 38147 authorized deferral of expense to Account No. 182.3
Docket 40824 authorized amortization of 12/31/12 deferred balance.
Docket No. 42004 extended the amortization period of the 12/31/12 balance; remaining balance of $3,025,000 as of 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2013 deferral of $3,468,975 over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2014 deferral of $196,032 through 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 43695 authorized revised amortization of total deferred pension and OPEB expense of $3,583,510 to be amortized over 24 months beginning 6/11/15.
Docket No. 45524 authorized revised amortization of the total deferred pension and OPEB expense of $1,841,525 to be amortized over 24 months beginning 7/1/16
Docket No. 47527 authorized revised amortization of the total deferred pension and OPEB expense of $(664,316) to be amortized over 24 months beginning 2/1/18
Docket No. 49831 authorized revised amortization of the total deferred pension and OPEB expense of $1,574,975 to be amortized over 12 months beginning 4/1/19

Pension and Benefit Expense	$	28,495,540
Pension Tracker		267,703
Amortization		—
Pension and Benefit Expense as Reported	$	28,763,243

(e) Concept: FuelSteamPowerGeneration

FERC 501 - Fuel includes $1,232,009.35 of ancillary service cost reclassed to gen book trading cost.

(f) Concept: Allowances

The amount of $34,908 includes the amortization of previously deferred Nox allowance cost of 34,908.02 (authorized in NMPRC case No. 19-00170).

(g) Concept: PurchasedPower

FERC 555 - Purchased Power includes $20,476 of ancillary service cost reclassed to gen book trading cost.

(h) Concept: OtherExpensesOtherPowerSupplyExpenses

The total of this account includes deferred expenses related to Fuel and Renewable Energy Costs as follows:

Fuel	$	(50,303,322)
RECs and other renewable energy costs	$	(792,030)

(i) Concept: UncollectibleAccounts

Recovery of 2019 write off - $643k

(j) Concept: EmployeePensionsAndBenefits

Texas PUC Docket No. 38147 authorized deferral of expense to Account No. 182.3
Docket 40824 authorized amortization of 12/31/12 deferred balance.
Docket No. 42004 extended the amortization period of the 12/31/12 balance; remaining balance of $3,025,000 as of 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2013 deferral of $3,468,975 over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2014 deferral of $196,032 through 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 43695 authorized revised amortization of total deferred pension and OPEB expense of $3,583,510 to be amortized over 24 months beginning 6/11/15.
Docket No. 45524 authorized revised amortization of the total deferred pension and OPEB expense of $1,841,525 to be amortized over 24 months beginning 7/1/16
Docket No. 47527 authorized revised amortization of the total deferred pension and OPEB expense of $(664,316) to be amortized over 24 months beginning 2/1/18

Pension and Benefit Expense	$	27,303,144
Pension Tracker		63,425
Amortization		1,824,093
Pension and Benefit Expense as Reported	$	29,190,662

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

					Actual Demand (MW)				POWER EXCHANGES		COST/SETTLEMENT OF POWER			
Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	Aeolus Wind, LLC	SF	QF											
2	Borger Energy Associates	RQ	PSA	224			1,451,327				11,742,591	61,291,541		73,034,132
3	Caprock Wind LP	LU	REPA				281,070					9,845,889		9,845,889
4	Chaves County Solar, LLC	LU	SEPA				163,133					6,233,556	[(a)]800,126	7,033,682
5	Cirrus Wind I LLC	SF	QF				0					11		11

6	Lea Power Partners	RQ	PSA	604			3,380,443				52,818,313	183,001,886		235,820,199
7	Lubbock Power & Light	OS	SPSV3				243,466					68,317,170		68,317,170
8	Lorenzo Wind LLC	LU	REPA				334,999					6,308,030	[b]629,067	6,937,097
9	Mammoth Plains Wind Project Holdings, LLC	LU	REPA				800,974					17,350,674	[c]1,048,391	18,399,065
10	Mesalands Community College LP	SF	QF				1,910					24,763	[d](1,128)	23,635
11	National Windmill Project, Inc.	SF	QF				165					2,659	[e](112)	2,547
12	Net Metering	OS	N/A				8,370					335,259		335,259
13	Orion Engineered Carbons LLC	SF	QF				36,461					1,057,869	[f](24,834)	1,033,035
14	Palo Duro Wind LLC	LU	REPA				1,028,779					22,801,557	[g]4,816,873	27,618,430
15	Pantex Wind	SF	QF				6,245					89,797	[h](9,681)	80,116
16	Pleasant Hills Wind Energy	SF	QF				14,656					429,180	[i](19,706)	409,474
17	Ralls Wind Farm, LLC	SF	QF				7,212					180,404	[j](13,856)	166,548
18	Roosevelt Wind Ranch LLC	LU	REPA				1,060,872					23,653,297	[k]536,026	24,189,323
19	Roswell Solar, LLC	LU	SEPA				160,756					6,075,594	[l]830,265	6,905,859
20	San Juan Mesa Wind Project, LLC	LU	REPA				263,705					9,396,271	[m]4,281,022	13,677,293
21	SoCore Clovis 1, LLC	LU	SEPA				2,576					(43,785)		(43,785)
22	Southwest Power Pool	OS	SPSV3				3,257,613					216,886,798	[n]6,142,977	223,029,775
23	Spinning Spur Wind LLC	LU	REPA				652,451					25,184,596	[o]2,065,315	27,249,911
24	Sun Edison Solar SPS LLC	LU	SEPA				106,814					14,423,443		14,423,443
25	Texico Wind, LP	SF	QF				544					8,537	[p](194)	8,343
26	Tokai Carbon CB LTD	RQ	PSA	1			6,282				35,050	144,661		179,711
27	Tokai Carbon CB LTD	SF	QF				2,746					47,168	[q](3,284)	43,884
28	West Texas A&M University	SF	QF				6,923					249,490	[r](8,232)	241,258
29	Wildorado Wind LP	LU	REPA				668,954					22,489,039	[s]628,167	23,117,206
30	Wildcat Ranch Wind Project LLC	LU	REPA				657,385					12,378,551	[t]758,619	13,137,170
15	TOTAL						14,606,831	0	0	0	64,595,954	708,163,905	22,455,821	795,215,680

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(b) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(c) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(d) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(e) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(f) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(g) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(h) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(i) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(j) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(k) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(l) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(m) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(n) Concept: OtherChargesOfPurchasedPower

SPP market charges and ASM revenue		
ARR/TCR	$	(71,878,226)
LTPP		36,012
Reg, Spin, Supp		8,081,285
Other SPP Chgs		69,903,906
	$	6,142,977

(o) Concept: OtherChargesOfPurchasedPower

Curtailment Adjustment

(p) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(q) Concept: OtherChargesOfPurchasedPower

SPP market charge pass through

(r) Concept: OtherChargesOfPurchasedPower
SPP market charge pass through
(s) Concept: OtherChargesOfPurchasedPower
Curtailment Adjustment
(t) Concept: OtherChargesOfPurchasedPower
Curtailment Adjustment

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

									TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Southwest Power Pool	NA	NA	[(a)] LFP	SPP OATT	Various	Various		10,112,556	10,112,556	285,754,868		[(b)] 1,638,697	287,393,565
35	TOTAL							0	10,112,556	10,112,556	285,754,868		1,638,697	287,393,565

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode
LFP, SFP, FNO, FNS, OS
(b) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Radial Line Facilities & Meter Charges

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Southwest Power Pool	[(a)] FNS			173,068,035	1,974,678	[(b)] 919,140	175,961,853
2	Swisher	OS					[(c)] 18,960	18,960
3	NPEC	OS			7,127		[(d)] 1,080	8,207
4	Lamb County	OS					[(e)] 5,000	5,000
	TOTAL		0	0	173,075,162	1,974,678	944,180	175,994,020

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

FNS, LFP, SFP, OS

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

Other Charges for Southwest Power Pool (SPP) include the following:

SPP Annual Membership Fee	$	6,000
Direct Assignment Charges (Meter Readings, Radial Facilities, Distribution, Other)	$	388,488
Direct Assigned Upgrade Charges per Z2 Tariff	$	524,652
	$	919,140

(c) Concept: OtherChargesTransmissionOfElectricityByOthers

Other Charges for Swisher include monthly wheeling charges.

Wheeling Charge	$	17,400
Annual Equipment Rental Fee	$	1,560
	$	18,960

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

Other Charges for North Plains Electric Coop (NPEC) include monthly customer fees.

(e) Concept: OtherChargesTransmissionOfElectricityByOthers

Other Charges for Lamb County include an annual fee for the use of a transmission line.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	46,901
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Service Company Allocation of Shareholder Meetings	62,472
7	Service Company Allocation of Director Fees and Exp	516,613
8	Service Company Allocation of Industry Association Dues	941,832
46	TOTAL	1,567,818

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			[a]22,162,392		22,162,392
2	Steam Production Plant	67,502,525	728,126	481,023		68,711,674
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	70,591,800	1,948,633			72,540,433
7	Transmission Plant	[b]93,870,334	782	2,024,368		95,895,484
8	Distribution Plant	42,701,996	309,692	252,989	(188,803)	43,075,874
9	Regional Transmission and Market Operation					
10	General Plant	28,734,953		188,330		28,923,283
11	Common Plant-Electric					
12	TOTAL	303,401,608	2,987,233	25,109,102	(188,803)	[c]331,309,140

B. Basis for Amortization Charges

Column (d) line 12: Land and Water Rights are being amortized over the life of the asset. Column (d) line 12: Leased Property improvements are being amortized over the life of the lease. Column (d) line 12: Computer software is being amortized over its expected useful life. Column (e) line 8: Contributions in Aid of Construction Gross-up recorded as a Regulatory Liability and amortized over 20 years, and thus appears as a credit to expense.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production-Coal						
13	[d]310	345					0 years

14	[e] 310	297			2		15 years, 1 month, 28 days
15	[f] 310	10,220			4		15 years, 29 days
16	311	91,433	57 years	(42)	4		18 years, 8 months, 5 days
17	312	478,995	57 years	(10)	3		15 years, 4 months, 24 days
18	314	196,159	57 years	(12)	2		17 years, 8 months, 1 day
19	315	32,652	57 years	(8)	2		26 years, 7 months, 28 days
20	316	11,362	57 years	(30)	3		20 years, 7 months, 2 days
21	317	260					
22	Subtotal Steam Prod-Coal	821,723					
23	Steam Production-Gas						
24	[g] 310	4,011					0 years
25	[h] 310	801			4		9 years, 1 month, 28 days
26	[i] 310	1,331			1		6 years, 2 months, 16 days
27	[j] 310	73			2		14 years, 4 months, 28 days
28	311	157,773	63 years	(17)	4		12 years, 2 months, 27 days
29	312	556,382	63 years	(10)	4		11 years, 9 months, 15 days
30	314	335,033	63 years	(10)	4		12 years, 3 months, 26 days
31	315	59,231	63 years	(11)	4		10 years, 5 months, 12 days
32	316	21,576	63 years	(16)	3		13 years, 3 months, 22 days
33	317	25,559					
34	Subtotal Steam Prod-Gas	1,161,770					
35	Other Production						
36	[k] 340	115					0 years
37	[l] 340	1					0 years
38	[m] 340	954					0 years
39	341	129,970	41 years	(2)	4		23 years, 5 months, 1 day
40	342	6,197	41 years	(9)	3		14 years, 4 months, 17 days
41	343	55,916	41 years	(4)	3		18 years, 2 months, 9 days
42	344	1,504,177	41 years	(2)	4		23 years, 4 months, 2 days

43	345	104,056	41 years	(2)	4		24 years, 4 days
44	346	4,895	41 years	(4)	3		23 years, 11 months, 23 days
45	347	49,157					
46	Subtotal Other Prod	1,855,438					
47	Transmission						
48	[n] 350	10,579					0 years
49	[o] 350	160,387	80 years		1	R4	66 years, 10 months, 17 days
50	[p] 350	217					0 years
51	352	139,625	69 years	(13)	2	R4	56 years, 3 months, 7 days
52	353	1,418,536	58 years	(20)	2	R1.5	48 years, 7 months, 6 days
53	354	8,237	75 years	(5)	2	R4	45 years, 7 months, 13 days
54	355	1,510,085	50 years	(43)	3	R2.5	38 years, 7 months, 17 days
55	356	543,373	50 years	(34)	3	R2	37 years, 3 months, 18 days
56	357	277	75 years		1	R3	23 years, 9 months, 7 days
57	358	490	45 years		2	R3	11 years, 6 months
58	359	518	65 years	(5)	2	R4	57 years
59	359.1	25					
60	Subtotal Transmission	3,792,349					
61	Distribution						
62	[q] 360	12,598					0 years
63	[r] 360	16,011	62 years		2	R4	55 years, 5 months, 19 days
64	361	48,064	57 years	(13)	2	R1.5	53 years, 9 months, 29 days
65	362	340,351	55 years	(15)	2	R1.5	45 years, 11 months, 27 days
66	364	412,830	53 years	(47)	3	R0.5	44 years, 6 months, 29 days
67	365	317,208	47 years	(36)	3	R0.5	40 years, 6 months, 26 days
68	366	26,271	59 years	(17)	2	R2.5	38 years, 10 months, 10 days
69	367	52,865	47 years	(17)	2	R1.5	35 years
70	368	246,645	45 years	(15)	3	R1	33 years, 5 months, 5 days
71	[s] 369	54,044	45 years	(26)	3	R1.5	28 years, 2 months, 19 days
72	[t] 369	49,251	0 years	(26)	3	R1.5	26 years, 2 months, 1 day
73	370	69,830	39 years	(10)	3	R2	27 years, 11 months, 5 days

74	371	13,046	25 years	(18)	4	R0.5	4 years, 3 months, 26 days
75	373	36,312	51 years	(39)	3	R2	42 years, 1 month, 10 days
76	374	7,467					
77	Subtotal Distribution	1,702,793					
78	General						
79	[u] 389	3,060					0 years
80	[v] 389	46	55 years		2	R4	26 years, 3 months, 11 days
81	[w] 390	93,701	50 years	(8)	2	R1	35 years, 5 months, 27 days
82	[x] 390	3,663	[ao] 0 years				[ap] 0 years
83	[y] 391	22,644	24 years		4	SQ	17 years, 6 months, 22 days
84	[z] 391	96,214	5 years		19	SQ	2 years, 5 months, 19 days
85	[aa] [ab] 392	4,332	11 years		9	SQ	7 years, 3 months, 22 days
86	[ac] [ad] 392	50,485	11 years		9	SQ	4 years, 2 months, 5 days
87	[ae] [af] 392	12,130	15 years		6	SQ	11 years, 1 month, 24 days
88	[ag] [ah] 392	53,572	13 years		8	SQ	5 years, 5 months, 12 days
89	393	427	38 years		3	SQ	9 years, 5 months, 12 days
90	394	55,084	35 years		3	SQ	27 years, 7 months, 24 days
91	395	10,919	25 years		4	SQ	3 years, 8 months, 5 days
92	[ai] 396	13,718	17 years		5	SQ	8 years, 9 months, 15 days
93	[aj] 397	71,303	17 years		6	SQ	4 years, 5 months, 19 days
94	[ak] 397	50,726	17 years		6	SQ	11 years, 11 months, 16 days
95	[al] 397	69	17 years		6	SQ	11 years, 10 months, 24 days
96	[am] 397	22,525	17 years		6	SQ	11 years, 2 months, 12 days
97	398	2,747	25 years		4	SQ	7 years, 22 days
98	399.1						
99	Subtotal General	567,365					
100	TOTAL	[an] 9,901,438					

Page 336-337

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AmortizationOfLimitedTermPlantOrProperty

The Amortization of Limited Term Electric Plant within Account 404 includes the following:

Software	$	22,162,392

(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Transmission Serving Production	$	2,807,563

(c) Concept: DepreciationAndAmortization

A. Summary of Depreciation and Amortization Charges

NOTE: Amounts footnoted are based upon FERC ONLY RATES.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited Term Electric Plant (Account 404) (d)	Total (f)
1	Intangible Plant	$ —	$ 22,156,850	$ 22,156,850
2	Steam Production Plant	95,199,646	599,282	95,798,928
3	Nuclear Production Plant			—
4	Hydraulic Production Plant-Conventional			—
5	Hydraulic Production Plant-Pumped Storage			—
6	Other Production Plant	72,658,217	—	72,658,217
7	Transmission Plant	89,270,923	1,831,414	91,102,337
8	Distribution Plant	42,701,996	252,989	42,954,985
9	Regional Transmission and Market Operation			—
10	General Plant	25,768,623	187,882	25,956,505
11	Common Plant-Electric			—
12	Total	$ 325,599,405	$ 25,028,417	$ 350,627,822

B. Basis for Amortization Charges
Column (d) line 12: Land and Water Rights are being amortized over the life of the asset.

Column (d) line 12: Leased Property improvements are being amortized over the life of the lease.

Column (d) line 12: Computer software is being amortized over its expected useful life.

Footnote Line 7 column B

Transmission Serving Production	$	1,224,738

Footnote Line 1 column D
The amortization of Limited Term Electric Plant within Account 404 includes the following:

Software	$	22,156,850

NOTE: Amounts footnoted are based upon FERC ONLY RATES.

(d) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

310	Land Owned in Fee

(e) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

310.002	Land Rights

(f) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

310.003	Production Water Rights

(g) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

310	Land Owned in Fee

(h) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

310.002	Land Rights

(i) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

310.003	Production Water Rights

(j) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

310.004	Production Land Rights

(k) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

340	Other Production - Land Owned in Fee

(l) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

340	Other Production - Land Rights

(m) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

340	Other Production - Wind Land Owned in Fee

(n) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

350	Transmission - Land Owned in Fee

(o) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

350	Transmission - Land Rights

(p) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

350	Transmission - Wind Land Owned in Fee

(q) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

360	Distribution - Land Owned in Fee

(r) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

360	Distribution - Land Rights

(s) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

369.1	Overhead Services

(t) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

369.2	Underground Services

(u) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

389	General - Land Owned in Fee

(v) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

389	General - Land Rights

(w) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

390	Structures and Improvements

(x) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

390.7	Remodeling Leased Facilities

(y) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

391	Office Furniture and Equipment

(z) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

391.4 Network Equipment

(aa) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392.1 Transportation Equipment - Automobiles

(ab) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	7,305,664	120,519,000
396 Power Operated Equipment	727,904	13,718,000
Total	8,033,568	134,237,000

A reserve deficiency true-up was conducted in November 2015, pursuant to the rate case order. The true-up was allocated to accounts 392 Transportation Equipment and 396 Power Operated Equipment.

(ac) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	7,305,664	120,519,000
396 Power Operated Equipment	727,904	13,718,000
Total	8,033,568	134,237,000

A reserve deficiency true-up was conducted in November 2015, pursuant to the rate case order. The true-up was allocated to accounts 392 Transportation Equipment and 396 Power Operated Equipment.

(ad) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392.2 Transportation Equipment - Light Trucks

(ae) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392.3 Transportation Equipment - Trailers

(af) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	7,305,664	120,519,000
396 Power Operated Equipment	727,904	13,718,000
Total	8,033,568	134,237,000

A reserve deficiency true-up was conducted in November 2015, pursuant to the rate case order. The true-up was allocated to accounts 392 Transportation Equipment and 396 Power Operated Equipment.

(ag) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392.4 Transportation Equipment - Heavy Trucks

(ah) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	7,305,664	120,519,000
396 Power Operated Equipment	727,904	13,718,000
Total	8,033,568	134,237,000

A reserve deficiency true-up was conducted in November 2015, pursuant to the rate case order. The true-up was allocated to accounts 392 Transportation Equipment and 396 Power Operated Equipment.

(ai) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	7,305,664	120,519,000
396 Power Operated Equipment	727,904	13,718,000
Total	8,033,568	134,237,000

A reserve deficiency true-up was conducted in November 2015, pursuant to the rate case order. The true-up was allocated to accounts 392 Transportation Equipment and 396 Power Operated Equipment.

(aj) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

397	Communication Equipment

(ak) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

397.1	Communication Equipment - Two Way

(al) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

397.2	Communication Equipment - AES

(am) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

397.3	Communication Equipment - EMS

(an) Concept: DepreciablePlantBase

Footnotes: Section C

(1)	Column (b) Computation: Depreciable Plant Balances are an average of the beginning and ending plant balance for the year.
(2)	Columns (c) through (g): P337-P337.1 Changes to the underlying factors presented have occurred since filing the 2019 FERC Form 1 due to the implementation of approved rates in all three jurisdictions (Texas Case No. 49831, FERC Docket No. ER19-404, and New Mexico Case No. 19-00170).

(ao) Concept: UtilityPlantEstimatedAverageServiceLife

Account 390.7 is computed using an end of life method rather than a specific rate.

(ap) Concept: UtilityPlantWeightedAverageRemainingLife

Account 390.7 is computed using an end of life method rather than a specific rate.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Public Utilies Commission of Texas:											
2	Gross Receipts Assessment	1,413,740		1,413,740		Electric	928	1,413,740				
3	Docs. 47527 & 47588 - 2017 TX RC		369,021	369,021	346,832	Electric	928	369,021	22,189	186	369,021	
4	Docs. 49831 & 51644 - 2019 TX RC		(30,008)	(30,008)	(19,034)	Electric	928	(30,008)	12,442	186	(6,592)	
5	Docs. 49384 & 50708 - SPS PCF Rider		21,930	21,930	283,646	Electric	928	21,930	26,075	186	21,930	287,791
6	Doc. 49616 - TX Fuel Formula				16,230	Electric	928		456,345	186		472,575
7	Doc. 51802 - 2021 TX RC				520,500	Electric	928		67,120,406	186		67,640,906
8	Doc. 51644 - 2020 TX Surcharge				632	Electric	928		147,974	186		148,606
9	Miscellaneous items < $25K											
10	New Mexico Public Regulation Commission:											
11	Assessment Charges	2,736,000		2,736,000		Electric	928	2,736,000				
12	Case 17-00255-UT - 2017 NM RC					Electric	928					
13	Case No. S-1-SC-37308		48,475	48,475	1,128	Electric	928	48,475		186		1,128
14	Case 19-00170-UT - 2019 NM RC		487,098	487,098	865,912	Electric	928	487,098		186	487,097	378,815
15	Case No. 20-00238-UT - 2021 NM RC				629,052	Electric	928		1,316,253	186		1,945,305
16	Case No. 21-00172-UT		27,317	27,317		Electric	928					
17	Miscellaneous items < $25K		12,779	12,779		Electric	928	12,779				
18	Federal Energy Regulatory Commission:											
19	ER18-2358 - GridLiance Transmission Rate Case		120,115	120,115		Electric	928	120,115				
20	ER18-99 - GridLiance City of Nixa		370,988	370,988		Electric	928	370,988				

21	EL18-9-000 Notice of Complaint, Xcel Energy vs Southwest Power Pool		15,660	15,660		Electric	928	15,660				
22	ER20-277 - Production Depreciation Rates Update		90,373	90,373		Electric	928	90,373				
23	Miscellaneous items < $25K		16,240	16,240		Electric	928	16,240				
24	Other:											
25	Mandated Regulatory Notices		103,189	103,189		Electric	928	103,189				
26	Miscellaneous Items < $25,000		79,730	79,730		Electric	928	79,731				
46	TOTAL	4,149,740	1,732,907	5,882,647	2,644,898			5,855,331	69,101,684		871,456	70,875,126

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

Electric R, D and D Performed Internally:

- Generation
  - hydroelectric
    - Recreation fish and wildlife
    - Other hydroelectric
  - Fossil-fuel steam
  - Internal combustion or gas turbine
  - Nuclear
  - Unconventional generation
  - Siting and heat rejection
- Transmission
  - Overhead
  - Underground
- Distribution
- Regional Transmission and Market Operation
- Environment (other than equipment)
- Other (Classify and include items in excess of $50,000.)
- Total Cost Incurred

Electric, R, D and D Performed Externally:

- Research Support to the electrical Research Council or the Electric Power Research Institute
- Research Support to Edison Electric Institute
- Research Support to Nuclear Power Groups
- Research Support to Others (Classify)
- Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	B(1)	Electric Power Research Institute		498,507	[(a)] Various	498,507	
2	B(2)	Edison Electric Institute		314,472	[(b)] Various	314,472	
3	B(5)	Total		812,979		812,979	

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:		
930.2		498,507
	$	498,507

(b) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:		
426.4		43,141
930.2		271,331
	$	314,472

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	29,818,341		
4	Transmission	11,969,874		
5	Regional Market	491,872		
6	Distribution	12,501,835		
7	Customer Accounts	6,829,710		
8	Customer Service and Informational	2,097,422		
9	Sales	237,305		
10	Administrative and General	35,325,862		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	99,272,221		
12	Maintenance			
13	Production	15,752,436		
14	Transmission	626,934		
15	Regional Market			
16	Distribution	3,740,976		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	20,120,346		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	45,570,777		
21	Transmission (Enter Total of lines 4 and 14)	12,596,808		
22	Regional Market (Enter Total of Lines 5 and 15)	491,872		
23	Distribution (Enter Total of lines 6 and 16)	16,242,811		
24	Customer Accounts (Transcribe from line 7)	6,829,710		
25	Customer Service and Informational (Transcribe from line 8)	2,097,422		

26	Sales (Transcribe from line 9)	237,305		
27	Administrative and General (Enter Total of lines 10 and 17)	35,325,862		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	119,392,567	1,801,822	121,194,389
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			

58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	119,392,567	1,801,822	121,194,389
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	45,968,808	24,698,573	70,667,381
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	45,968,808	24,698,573	70,667,381
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,406,950	1,830,519	5,237,469
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,406,950	1,830,519	5,237,469
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Regulatory Assets (Acct No. 182.3)	1,141,091	15,238	1,156,329
80	Preliminary Survey and Investigation (Acct No. 183)	(33,246)	1,609	(31,637)
81	Miscellaneous Deferred Debits (Acct No. 186)	11,598		11,598
82	Nonutility (Accts No 416-417.1)	39,316	333	39,649
83	Miscellaneous Income and Deductions (Accts No 426.1-426.5)	106,522	1,365	107,887
84				
85				
86				
87				
88				
89				

90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,265,281	18,545	1,283,826
96	TOTAL SALARIES AND WAGES	170,033,606	28,349,459	198,383,065

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	209,446,444	306,925,275	358,009,180	428,588,888
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(305,455,297)	(358,078,293)	(415,383,947)	(455,261,878)
4	Transmission Rights	(8,206,639)	(27,723,074)	(45,465,368)	(79,222,600)
5	Ancillary Services	403,398,371	461,024,769	524,554,858	587,769,793
6	Other Items (list separately)				
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8					
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45					
46	TOTAL	299,182,879	382,148,677	421,714,723	481,874,203

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]0	[b]0	[c]4,018,886	[d]0	[e]0	1,296,588
2	Reactive Supply and Voltage	[f]0	[g]0	163,491	[h]0	[i]0	205,133
3	Regulation and Frequency Response	[j]0	[k]0	8,838,301	[l]0	[m]0	14,721,082
4	Energy Imbalance	[n]0	[o]0		[p]0	[q]0	
5	Operating Reserve - Spinning	[r]0	[s]0	9,752,340	[t]0	[u]0	11,617,295
6	Operating Reserve - Supplement	[v]0	[w]0	2,308,168	[x]0	[y]0	2,252,668
7	Other	[z]0	[aa]0		[ab]0	[ac]0	
8	Total (Lines 1 thru 7)			25,081,186			30,092,766

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available.

(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available.

(c) Concept: AncillaryServicesPurchasedAmount

Sch 1 Charges	$	358,535
SPP Administrative Fees - SSC&D	$	3,660,351
Total 'Scheduling, System Control, & Dispatch'	$	4,018,886

(d) Concept: AncillaryServicesSoldNumberOfUnits

Number of units is not available.

(e) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available.

(f) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available.

(g) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available.

(h) Concept: AncillaryServicesSoldNumberOfUnits

Number of units is not available.

(i) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available.

(j) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available.

(k) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available.

(l) Concept: AncillaryServicesSoldNumberOfUnits

Number of units is not available.

(m) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available.

(n) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available.

(o) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available.

(p) Concept: AncillaryServicesSoldNumberOfUnits

Number of units is not available.

(q) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available.

(r) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available.

(s) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available.
(t) Concept: AncillaryServicesSoldNumberOfUnits
Number of units is not available.
(u) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available.
(v) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available.
(w) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available.
(x) Concept: AncillaryServicesSoldNumberOfUnits
Number of units is not available.
(y) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available.
(z) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available.
(aa) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available.
(ab) Concept: AncillaryServicesSoldNumberOfUnits
Number of units is not available.
(ac) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available.

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	4,143	15	8	2,896	1,247				
2	February	4,403	12	10	3,006	1,397				
3	March	4,118	25	8	2,715	1,403				
4	Total for Quarter 1				8,617	4,047	0			0
5	April	4,328	6	19	2,667	1,661				
6	May	4,693	26	17	3,087	1,606				
7	June	5,450	23	18	3,672	1,778				
8	Total for Quarter 2				9,426	5,045	0			0
9	July	5,289	31	18	3,459	1,831				
10	August	5,619	9	18	3,638	1,981				
11	September	5,327	1	16	3,525	1,802				
12	Total for Quarter 3				10,622	5,614	0			0
13	October	4,229	9	17	3,108	1,120				
14	November	3,876	19	9	2,856	1,019				
15	December	3,913	7	8	2,843	1,070				
16	Total for Quarter 4				8,807	3,209	0			0
17	Total				37,472	17,915	0	0	0	0
	NAME OF SYSTEM: Southwestern Public Service									
1	January									
2	February									
3	March									
4	Total for Quarter 1									

5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total									

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2022-05-24	Year/Period of Report End of: 2021/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	20,859,917
3	Steam	9,708,641	23	Requirements Sales for Resale (See instruction 4, page 311.)	1,994,206
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,361,349
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	15,710
7	Other	5,046,091	27	Total Energy Losses	130,381
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	14,754,732	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	29,361,563
10	Purchases (other than for Energy Storage)	14,606,831			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	[a]0			
15	Transmission For Other (Wheeling)				
16	Received	10,112,556			
17	Delivered	10,112,556			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	29,361,563			

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2022-05-24	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NetEnergyThroughPowerExchanges

SPS has not found any FERC authority indicating the inadvertent energy is considered an exchange; therefore, inadvertent energy is not included in the exchange values reported

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Southwestern Public Service					
29	January	2,436,233	475,167	3,293	12	8
30	February	2,003,629	237,854	3,466	12	10
31	March	2,555,427	741,708	3,140	25	8
32	April	2,282,473	458,476	3,036	15	10
33	May	2,322,542	460,039	3,515	26	17
34	June	2,758,985	604,797	3,925	24	17
35	July	2,662,365	719,565	3,858	31	17
36	August	2,774,497	763,335	4,018	9	17
37	September	2,553,323	502,598	3,987	7	18
38	October	2,270,146	434,803	3,307	8	17
39	November	2,341,139	475,359	3,068	18	8
40	December	2,400,801	487,648	3,160	20	8
41	Total	29,361,560	6,361,349			

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: Carlsbad	Plant Name: Cunningham Gas	Plant Name: Cunningham Steam	Plant Name: Harrington	Plant Name: Jones Station	Plant Name: Jones Station Gas	Plant Name: Maddox Gas	Plant Name: Maddox Steam	Plant Name: Moore County	Plant Name: Nichols Station	Plant Name: Plant X	Plant Name: Quay County	Plant Name: Tolk
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Gas Turbine	Steam	Steam	Steam	Gas Turbine	Gas Turbine	Steam	Steam	Steam	Steam	Gas Turbine	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Outside Boiler	Outside Boiler	Conventional			Outside Boiler	Outside Boiler	Conventional	Outside Boiler		Outside Boiler
3	Year Originally Constructed	1977	1998	1957	1976	1971	2011	1976	1967	1938	1960	1952	2013	1982
4	Year Last Unit was Installed	1977	1998	1965	1980	1974	2013	1983	1983	1954	1968	1964	2013	1985
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	253.80	265.40	1,080.00	495.00	365.40	98.35	113.64	0.00	474.77	434.40	27.00	1,135.80
6	Net Peak Demand on Plant - MW (60 minutes)		208	234	1,048	481	380	67	119	0	455	263	24	1,056
7	Plant Hours Connected to Load		2,843	5,729	8,625	5,181	2,622	537	6,482	0	6,531	3,967	67	5,963
8	Net Continuous Plant Capability (Megawatts)	0	207	225	1,018	486	366	63	112	0	457	298	23	1,067
9	When Not Limited by Condenser Water	0	207	225	1,018	486	366	63	112	0	457	298	23	1,067
10	When Limited by Condenser Water	0	193	225	1,018	486	336	61	112	0	457	298	17	1,067
11	Average Number of Employees													
12	Net Generation, Exclusive of Plant Use - kWh		366,540,000	509,893,000	4,831,505,000	641,520,000	553,002,000	25,818,000	319,369,000		582,227,000	341,813,000	1,233,600	2,482,314,000
13	Cost of Plant: Land and Land Rights			61,235	1,231,653	2,274,924			25,991		818,610	1,752,767	103,888	10,862,393
14	Structures and Improvements		713,499	12,951,896	46,332,523	21,442,786	11,253,563	1,565,032	5,267,606		57,180,750	14,445,525	916,182	63,360,904

15	Equipment Costs		90,144,327	68,714,536	552,024,213	129,748,869	160,982,115	22,670,081	42,628,185		116,810,886	108,479,767	25,495,751	715,325,708
16	Asset Retirement Costs			36,284	(73,099)	2,515,362			(567,704)		(3,190,333)	(5,959,440)		32,173,281
17	Total cost (total 13 thru 20)		90,857,826	81,763,951	599,515,290	155,981,941	172,235,678	24,235,113	47,354,078		171,619,912	118,718,619	26,515,822	821,722,286
18	Cost per KW of Installed Capacity (line 17/5) Including		357.9899	308.0782	555.1067	315.1150	471.3620	246.4170	416.7026		361.4801	273.2933	982.0675	723.4745
19	Production Expenses: Oper, Supv, & Engr	4	22,727	171,103	1,153,012	627,969	14,862	25,889	120,089	3	300,898	595,101	4,696	632,258
20	Fuel		28,542,528	35,735,598	102,115,059	44,576,901	26,442,468	4,906,484	26,183,873		72,289,026	34,165,795	279,746	61,474,790
21	Coolants and Water (Nuclear Plants Only)													
22	Steam Expenses			1,456,591	3,827,174	1,783,037			779,486		1,006,957	378,221		2,936,758
23	Steam From Other Sources													
24	Steam Transferred (Cr)													
25	Electric Expenses		132,508	437,597	3,723,354	1,517,216	41,904	228,584	671,375		820,491	659,739	671	1,315,537
26	Misc Steam (or Nuclear) Power Expenses	119	95,596	1,069,947	3,958,677	1,755,593	21,954	51,261	551,154	119	2,346,316	1,472,156	20,533	2,490,508
27	Rents	5	18,318	238,272	911,000	406,314	11,979	20,866	117,172	5	312,248	250,440	3,785	574,308
28	Allowances													
29	Maintenance Supervision and Engineering		23,612	188,066	113,443	225,063	15,441	26,896	27,694		74,843	17,319	4,879	32,772
30	Maintenance of Structures		76,467	507,162	655,651	630,073	103,438	13,910	93,775		369,999	447,702	28,719	1,168,124
31	Maintenance of Boiler (or reactor) Plant	3		874,196	4,832,221	1,196,122			176,887	3	1,256,063	920,383		2,707,954
32	Maintenance of Electric Plant	1	455,860	1,014,451	2,279,843	2,278,348	331,364	574,855	139,838	1	1,094,304	1,018,730	94,428	2,001,133
33	Maintenance of Misc Steam (or Nuclear) Plant		2,557	512,193	3,302,011	621,832	294	512	506,675		903,240	1,045,921	13,294	1,739,027
34	Total Production Expenses	132	29,370,173	42,205,176	126,871,445	55,618,468	26,983,704	5,849,257	29,368,018	131	80,774,385	40,971,507	450,751	77,073,169
35	Expenses per Net kWh		0.0801	0.0828	0.0263	0.0867	0.0488	0.2266	0.0920		0.1387	0.1199	0.3654	0.0310

35	**Plant Name**	Cunningham Gas	Cunningham Steam	Harrington	Harrington	Harrington	Jones Station	Jones Station	Jones Station	Jones Station Gas	Maddox Gas	Maddox Steam	Moore County	Nichols Station	Plant X	Plant X	Plant X	Quay County	Tolk	Tolk	Tolk
36	Fuel Kind	Gas	Gas	Coal	Composite	Gas	Composite	Gas	Oil	Gas	Gas	Gas	Gas	Gas	Composite	Gas	Oil	Oil	Coal	Composite	Gas
37	Fuel Unit	Mcf	Mcf	T		Mcf		Mcf	bbl	Mcf	Mcf	Mcf	Mcf	Mcf		Mcf	bbl	bbl	T		Mcf
38	Quantity (Units) of Fuel Burned	4,350,819	5,401,764	2,888,447		40,359		7,717,433	31,579		325,981	3,463,677		8,123,741		4,006,444	29,367	6,647	1,489,976		82,159
39		1,019	1,014	1,022		8,835		1,018	0		1,017	1,020		1,023		1,022	1,022	136,784	0		4,347

	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)																				
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	6.560	6.610	35		41		6	42		15.050	7.550		9		8	30	42	40		19
41	Average Cost of Fuel per Unit Burned	6.560	6.620	35		50		6	42		15.050	7.560		9		8	30	42	40		21
42	Average Cost of Fuel Burned per Million BTU	6.440	6.530	2	2	6	6	6	15	4.430	14.800	7.410		9	8	8	10	15	2	2	5
43	Average Cost of Fuel Burned per kWh Net Gen	0.080	0.070							0.050	0.190	0.080									
44	Average BTU per kWh Net Generation	12,094.431	10,739.247		10,705		12,382			10,795.331	12,836.602	11,065.228		14,269	12,227			15,415		10,817	

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	

23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0

21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	Wind Turbine:												
2	Hale Wind Farm	2019	494.20		2,049,655,957.00	700,056,148	[a]1,464,553	7,590,094		5,336,556			
3	Sagamore Wind Farm	2020	522.80		2,049,841,387.00	841,203,949	1,611,502	1,322,196		2,587,003			

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantCostPerMw
The Plant Cost is manually calculated (not calculated by the FERC software) - (col g = col f / col c)

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
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Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1													850,989	862,996	1,668,125	3,382,110
2	(J30;01) GLENN (SWISHER CO)	SAGAMORE WIND SOUTH	345	345	SINGLE POLE	7.39	0.00	1	6-954 ACSR		4,340,479	4,340,479				
3	(J29;01) CROSSROADS	SAGAMORE WIND SOUTH	345	345	SINGLE POLE	6.30	0.00	1	6-954 ACSR		5,139,124	5,139,124				
4	(J28;01) PHANTOM	ROADRUNNER	345	345	H-FRAME	22.16	0.00	1	6-795 ACSS	1,470,682	26,994,888	28,465,570				
5	(J27;01) CHINA DRAW	PHANTOM	345	345	H-FRAME	20.22	0.00	1	6-795 ACSS	1,709,591	23,678,034	25,387,625				
6	(J26-KS;01) CARPENTER	HITCHLAND	345	345	H-FRAME	12.16	0.00	1	6-795 ACSR	871,770	4,523,204	5,394,974				
7	(J26-OK;01) CARPENTER	HITCHLAND	345	345	H-FRAME	38.03	0.00	1	6-795 ACSR	15,606		15,606				
8	(J26-TX;01) CARPENTER	HITCHLAND	345	345	H-FRAME	0.51	0.00	1	6-795 ACSR							
9	(J25;01) CARPENTER	FINNEY SW STA	345	345	H-FRAME	67.29	0.00	1	6-795 ACSR	1,157,018	8,553,500	9,710,518				
10	(J24;01) EDDY CO INTG	KIOWA	345	345	H-FRAME	34.01	0.00	1	6-795 ACSS	930,590	38,477,219	39,407,809				
11	(J23;01) KIOWA	ROADRUNNER	345	345	H-FRAME	40.31	0.00	1	6-795 ACSR	852,111	44,359,478	45,211,589				

12	(J22;01) CHINA DRAW	NORTH LOVING	345	345	H-FRAME	18.12	0.00	1	6-795 ACSS	2,240,588	18,732,177	20,972,765				
13	(J21;01) KIOWA	NORTH LOVING	345	345	H-FRAME	21.89	0.00	1	6-795 ACSS	1,485,856	23,406,998	24,892,854				
14	(J20;01) HOBBS GENERATING	KIOWA	345	345	H-FRAME	47.04	0.00	1	6-795 ACSS	3,417,223	47,665,543	51,082,766				
15	(J20;01) HOBBS GENERATING	KIOWA	345	345	SINGLE POLE	0.81	0.00	1	6-795 ACSS							
16	(J18-NM;01) HOBBS GENERATING	YOAKUM CO INTG	345	345	H-FRAME	36.30	0.00	1	6-795 ACSS	2,458,949	36,326,223	38,785,172				
17	(J18-TX;01) HOBBS GENERATING	YOAKUM CO INTG	345	345	H-FRAME	25.48	0.00	1	6-795 ACSS	1,670,565	31,638,532	33,309,097				
18	(J17;01) TUCO	YOAKUM CO INTG	345	345	H-FRAME	104.56	0.00	1	6-795 ACSS	10,577,117	111,007,610	121,584,727				
19	(J15-NM;01) CROSSROADS	TOLK STA	345	345	H-FRAME	20.00	0.00	1	6-795 ACSR	241,431	2,893,944	3,135,375				
20	(J15-TX;01) CROSSROADS	TOLK STA	345	345	H-FRAME	31.84	0.00	1	6-795 ACSR	445,174	4,669,378	5,114,552				
21	(J14;01) CROSSROADS	EDDY CO INTG	345	345	H-FRAME	105.87	0.00	1	6-795 ACSR	1,368,108	18,106,255	19,474,363				
22	(J13-OK;02) HITCHLAND	OKPS (BEAVER CO)	345	345	SINGLE POLE	0.00	28.92	1	6-1590 ACSR	54,107	6,964,051	7,018,158				
23	(J13-TX;02) HITCHLAND	OKPS (BEAVER CO)	345	345	SINGLE POLE	0.00	0.38	1	6-1590 ACSR		150,186	150,186				
24	(J12-OK;01) HITCHLAND	OKPS (BEAVER CO)	345	345	SINGLE POLE	28.92	0.00	1	6-1590 ACSR	1,859,566	40,145,041	42,004,607				
25	(J12-TX;01) HITCHLAND	OKPS (BEAVER CO)	345	345	SINGLE POLE	0.38	0.00	1	6-1590 ACSR	34,262	1,743,136	1,777,398				
26	(J11-OK;01) BORDER	TUCO	345	345	SINGLE POLE	6.19	0.00	1	6-795 ACSS	259,826	4,718,648	4,978,474				
27	(J11-TX;01) BORDER	TUCO	345	345	3 POLE	0.87	0.00	1	6-795 ACSS	22,802,327	171,439,100	194,241,427				
28	(J11-TX;01) BORDER	TUCO	345	345	H-FRAME	18.63	0.00	1	6-795 ACSS							
29	(J11-TX;01) BORDER	TUCO	345	345	SINGLE POLE	175.67	0.00	1	6-795 ACSS							
30	(J06;01) HITCHLAND	POTTER CO SW STA	345	345	H-FRAME	102.59	0.00	1	6-795 ACSR	4,664,945	36,280,931	40,945,876				
31	(J05-KS;01) FINNEY SW STA	LAMAR 345KV SW STA	345	345	H-FRAME	78.76	0.00	1	6-795 ACSR	49,567	21,958,432	22,007,999				
32	(J04;01) FINNEY SW STA	HOLCOMB POWER PLANT 345KV	345	345	H-FRAME	0.75	0.00	1	6-795 ACSR	3,892,153	22,913,323	26,805,476				
33	(J01;01) OKLAUNION / WILBARGER CO. (PSO)	TUCO	345	345	H-FRAME	160.31	0.19	1	6-795 ACSR	2,428,536	26,351,940	28,780,476				

34	(R13;01) HALE CO. WIND FARM	TUCO	230	230	SINGLE POLE	14.31	0.00	1	6-1272 ACSR		13,196,856	13,196,856				
35	(R13;01) HALE CO. WIND FARM	TUCO	230	230	UNDERGROUND	0.14	0.00	1	N/A N/A							
36	(R12;01) AMOCO WASSON OXY CO2 RECOVERY	MAHONEY	230	230	K-FRAME	3.90	0.00	1	3-795 ACSR		291,696	291,696				
37	(R11;01) BRU	MAHONEY	230	230	K-FRAME	2.68	0.00	1	3-795 ACSR		418,330	418,330				
38	(R10-NM;01) HOBBS GENERATING	INK BASIN	230	230	H-FRAME	0.78	0.00	1	3-795 ACSR							
39	(R10-NM;01) HOBBS GENERATING	INK BASIN	230	230	K-FRAME	22.32	0.00	1	3-795 ACSR							
40	(R10-TX;01) HOBBS GENERATING	INK BASIN	230	230	K-FRAME	7.59	0.00	1	3-795 ACSR		556,872	556,872				
41	(R07;01) INK BASIN	YOAKUM CO INTG	230	230	K-FRAME	17.40	0.29	1	3-795 ACSR		415,207	415,207				
42	(R06;01) NEEDMORE	YOAKUM CO INTG	230	230	H-FRAME	13.79	0.00	1	3-795 ACSR	334,131	10,638,208	10,972,339				
43	(R06;01) NEEDMORE	YOAKUM CO INTG	230	230	K-FRAME	59.34	0.00	1	3-795 ACSR							
44	(R06;01) NEEDMORE	YOAKUM CO INTG	230	230	SPECIAL	1.12	0.00	1	3-795 ACSR							
45	(R05;01) NEEDMORE	TOLK STA	230	230	K-FRAME	13.66	0.00	1	3-795 ACSR	61,477	1,747,035	1,808,512				
46	(R04-NM;01) ANDREWS CO.	HOBBS GENERATING	230	345	H-FRAME	0.47	0.00	1	3-795 ACSR							
47	(R04-NM;01) ANDREWS CO.	HOBBS GENERATING	230	345	H-FRAME	22.61	0.00	1	6-795 ACSR							
48	(R04-TX;01) ANDREWS CO.	HOBBS GENERATING	230	345	H-FRAME	7.81	0.00	1	6-795 ACSR		869,380	869,380				
49	(K99;01) CARLISLE	WOLFFORTH INTG	230	230	SINGLE POLE	13.04	0.00	1	3-795 ACSR	2,799,489	8,909,555	11,709,044				
50	(K98;01) CHANNING	XIT	230	230	SINGLE POLE	32.37	0.00	1	3-795 ACSR	41,398	623,112	664,510				
51	(K97;01) CHANNING	POTTER CO SW STA	230	230	SINGLE POLE	41.79	0.00	1	3-795 ACSR	66,461	778,059	844,520				
52	(K94;01) CIRRUS	GRASSLAND INTG	230	345	H-FRAME	1.67	0.00	1	6-795 ACSR	(1)	660,691	660,690				
53	(K94;01) CIRRUS	GRASSLAND INTG	230	345	SINGLE POLE	8.42	0.00	1	6-795 ACSR							
54	(K92;01) CUNNINGHAM	HOBBS GENERATING	230	230	K-FRAME	3.03	0.00	1	3-795 ACSR		1,478,605	1,478,605				
55	(K91;01) NEWHART	PLANT X	230	230	K-FRAME	0.57	1.27	1	3-795 ACSR		2,784,260	2,784,260				

56	(K91;01) NEWHART	PLANT X	230	230	SINGLE POLE	37.93	0.00	1	3-795 ACSR							
57	(K90;01) NEWHART	POTTER CO SW STA	230	230	K-FRAME	67.64	0.00	1	3-795 ACSR	286,505	10,806,480	11,092,985				
58	(K88;01) NEWHART	SWISHER CO INTG	230	230	SINGLE POLE	21.31	0.00	1	3-795 ACSR	891,615	10,915,732	11,807,347				
59	(K87;01) AMARILLO SOUTH	RANDALL CO	230	230	SINGLE POLE	8.36	0.00	1	3-795 ACSR	1,108,488	7,214,262	8,322,750				
60	(K86;01) HARRINGTON STA	ROLLING HILLS	230	230	H-FRAME	4.84	0.14	1	3-795 ACSR		1,814,387	1,814,387				
61	(K86;01) HARRINGTON STA	ROLLING HILLS	230	230	K-FRAME	0.48	0.00	1	3-795 ACSR							
62	(K85;01) POTTER CO SW STA	ROLLING HILLS	230	230	H-FRAME	4.85	0.00	1	3-795 ACSR		4,016,313	4,016,313				
63	(K85;01) POTTER CO SW STA	ROLLING HILLS	230	230	SINGLE POLE	1.15	0.00	1	3-795 ACSR							
64	(K84;01) PLEASANT HILL	ROOSEVELT CO INTG	230	230	SINGLE POLE	19.54	0.00	1	3-795 ACSR	1,305,733	12,604,311	13,910,044				
65	(K83;01) OASIS INTERCHANGE	PLEASANT HILL	230	230	H-FRAME	7.20	0.00	1	3-795 ACSR	886,966	12,641,398	13,528,364				
66	(K83;01) OASIS INTERCHANGE	PLEASANT HILL	230	230	SINGLE POLE	21.35	0.00	1	3-795 ACSR							
67	(K82;01) BRU	OXY BENNETT RANCH	230	230	3 POLE	0.11	0.00	1	3-795 ACSR							
68	(K79-TX;01) BRU	YOAKUM CO INTG	230	230	K-FRAME	5.35	0.00	1	3-795 ACSR	22,358	643,346	665,704				
69	(K76;01) HITCHLAND	OCHILTREE SUB	230	230	SINGLE POLE	38.14	0.00	1	3-795 ACSR	1,809,214	18,432,877	20,242,091				
70	(K75;01) HITCHLAND	MOORE CO	230	230	H-FRAME	62.68	0.02	1	3-795 ACSR	2,565,040	28,946,409	31,511,449				
71	(K74-OK;01) SWEETWATER (AEP)	WHEELER CO.	230	230	K-FRAME	0.16	0.00	1	3-795 ACSR							
72	(K74-TX;01) SWEETWATER (AEP)	WHEELER CO.	230	230	K-FRAME	14.04	0.00	1	3-795 ACSR		1,132,336	1,132,336				
73	(K73;01) GRAPEVINE INTG	WHEELER CO.	230	230	K-FRAME	36.87	0.00	1	3-795 ACSR		2,351,043	2,351,043				
74	(K69;01) MUSTANG INTG	SEMINOLE INTG	230	230	SINGLE POLE	18.05	0.00	1	3-795 ACSR	880,706	8,383,885	9,264,591				
75	(K68;01) PECOS	SEVEN RIVERS	230	230	H-FRAME	19.03	0.00	1	3-795 ACSR	464,861	7,176,410	7,641,271				
76	(K68;01) PECOS	SEVEN RIVERS	230	230	SINGLE POLE	1.64	0.00	1	3-795 ACSR							
77	(K67;01) PECOS	POTASH JUNCTION	230	230	H-FRAME	14.65	0.00	1	3-795 ACSR	943,425	4,865,979	5,809,404				
78	(K66;01) CHAVES CO	SAN JUAN MESA	230	230	SINGLE POLE	51.73	0.00	1			1,666,784	1,666,784				

									3-795 ACSR							
79	(K65;01) OASIS INTERCHANGE	SAN JUAN MESA	230	230	K-FRAME	46.62	0.00	1	3-795 ACSR		580,914	580,914				
80	(K63;01) AMARILLO SOUTH	SWISHER CO INTG	230	230	K-FRAME	49.10	0.00	1	3-795 ACSR	192,413	3,735,728	3,928,141				
81	(K63;01) AMARILLO SOUTH	SWISHER CO INTG	230	230	SINGLE POLE	0.99	5.78	1	3-795 ACSR							
82	(K62;01) AMARILLO SOUTH	NICHOLS STA	230	230	H-FRAME	0.38	0.24	1	3-795 ACSR		986,937	986,937				
83	(K62;01) AMARILLO SOUTH	NICHOLS STA	230	230	K-FRAME	2.97	10.26	1	3-795 ACSR							
84	(K62;01) AMARILLO SOUTH	NICHOLS STA	230	230	SINGLE POLE	5.78	0.00	1	3-795 ACSR							
85	(K60;01) EDDY CO INTG	SEVEN RIVERS	230	230	H-FRAME	24.33	0.00	1	3-795 ACSR	373,453	6,280,883	6,654,336				
86	(K59;01) BUSHLAND	POTTER CO SW STA	230	230	H-FRAME	1.03	0.00	1	3-795 ACSR		2,242,874	2,242,874				
87	(K59;01) BUSHLAND	POTTER CO SW STA	230	230	K-FRAME	15.09	0.16	1	3-795 ACSR							
88	(K59;01) BUSHLAND	POTTER CO SW STA	230	230	SINGLE POLE	0.00	1.15	1	3-795 ACSR							
89	(K56;01) MUSTANG INTG	YOAKUM CO INTG	230	230	K-FRAME	12.97	0.00	1	3-795 ACSR	110,146	3,446,828	3,556,974				
90	(K56;01) MUSTANG INTG	YOAKUM CO INTG	230	230	SINGLE POLE	0.90	0.00	1	3-795 ACSR							
91	(K55;01) AMOCO WASSON OXY CO2 RECOVERY	MUSTANG INTG	230	230	H-FRAME	3.54	0.00	1	3-795 ACSR		117,523	117,523				
92	(K53;01) GRAPEVINE INTG	NICHOLS STA	230	230	K-FRAME	52.75	0.00	1	3-795 ACSR	299,576	9,525,987	9,825,563				
93	(K52;01) CUNNINGHAM	POTASH JUNCTION	230	230	H-FRAME	39.88	0.00	1	3-795 ACSR	35,679	7,760,234	7,795,913				
94	(K51;01) OASIS INTERCHANGE	ROOSEVELT CO INTG	230	230	K-FRAME	9.68	0.00	1	3-795 ACSR	385,284	8,442,471	8,827,755				
95	(K47;01) GRASSLAND INTG	JONES PLANT	230	345	K-FRAME	26.72	0.00	1	6-795 ACSR	1,003,850	4,012,094	5,015,944				
96	(K46;01) PLANT X	SUNDOWN SW. STA.	230	230	2 POLE	0.25	0.60	1	3-795 ACSR	753,723	14,488,279	15,242,002				
97	(K46;01) PLANT X	SUNDOWN SW. STA.	230	230	K-FRAME	44.90	0.00	1	3-795 ACSR							
98	(K46;01) PLANT X	SUNDOWN SW. STA.	230	230	SINGLE POLE	0.00	2.49	1	3-795 ACSR							
99	(K45;02) PLANT X	TOLK STA	230	230	K-FRAME	9.94	0.17	1	3-1011.3 ACCC-ULS	10,937	267,363	278,300				

100	(K44;01) EAST PLANT	HARRINGTON STA	230	230	SINGLE POLE	6.95	0.11	1	3-795 ACSR	74,484	3,030,452	3,104,936				
101	(K43;01) HARRINGTON STA	PRINGLE	230	230	K-FRAME	59.20	0.00	1	3-795 ACSR	691,754	7,647,371	8,339,125				
102	(K42;01) TOLK STA	TUCO	230	230	2 POLE	0.75	0.00	1	3-795 ACSR	80,573	6,237,140	6,317,713				
103	(K42;01) TOLK STA	TUCO	230	230	K-FRAME	51.00	0.00	1	3-795 ACSR							
104	(K42;01) TOLK STA	TUCO	230	230	SINGLE POLE	2.62	0.00	1	3-795 ACSR							
105	(K39;01) CARLISLE	MCDONALD (LP&L)	230	230	2 POLE	0.18	0.00	1	3-795 ACSR							
106	(K38;01) CHAVES CO	EDDY CO INTG	230	230	H-FRAME	2.73	0.00	1	3-795 ACSR	262,396	5,613,741	5,876,137				
107	(K38;01) CHAVES CO	EDDY CO INTG	230	230	K-FRAME	49.91	0.00	1	3-795 ACSR							
108	(K37;01) LAMB CO INTG	TOLK STA	230	230	K-FRAME	35.12	0.00	1	3-795 ACSR	194,338	4,908,141	5,102,479				
109	(K34;01) AMOCO	AMOCO SW. STA.	230	230	SINGLE POLE	0.04	0.00	1	3-795 ACSR							
110	(K33;01) AMOCO SW. STA.	YOAKUM CO INTG	230	230	H-FRAME	36.96	0.00	1	3-795 ACSR	104,491	3,188,710	3,293,201				
111	(K32;01) HARRINGTON STA	POTTER CO SW STA	230	230	K-FRAME	10.89	0.33	1	3-795 ACSR	71,645	502,725	574,370				
112	(K31;01) MOORE CO	POTTER CO SW STA	230	230	K-FRAME	47.89	0.00	1	3-795 ACSR	344,824	4,754,344	5,099,168				
113	(K30-NM;02) ROOSEVELT CO INTG	TOLK STA	230	230	K-FRAME	9.55	0.00	1	3-795 ACSR	1,375,140	5,408,836	6,783,976				
114	(K30-TX;02) ROOSEVELT CO INTG	TOLK STA	230	230	H-FRAME	7.77	0.00	1	3-795 ACSR	144,944	5,555,414	5,700,358				
115	(K30-TX;02) ROOSEVELT CO INTG	TOLK STA	230	230	K-FRAME	22.68	0.00	1	3-795 ACSR							
116	(K27;01) PLANT X	TOLK STA	230	230	K-FRAME	9.64	0.00	1	3-795 ACCR		(122,674)	(122,674)				
117	(K24;01) CARLISLE	TUCO	230	230	H-FRAME	1.49	0.00	1	3-795 ACSR	510,050	4,553,107	5,063,157				
118	(K24;01) CARLISLE	TUCO	230	230	K-FRAME	25.68	0.00	1	3-795 ACSR							
119	(K23;01) CUNNINGHAM	EDDY CO INTG	230	230	K-FRAME	58.81	0.00	1	3-795 ACSR	10,840	7,437,038	7,447,878				
120	(K21;01) DEAF SMITH INTERCHANGE	PLANT X	230	230	H-FRAME	2.73	0.00	1	3-795 ACSR		9,185,775	9,185,775				
121	(K21;01) DEAF SMITH INTERCHANGE	PLANT X	230	230	K-FRAME	44.15	0.00	1	3-795 ACSR							
122		RANDALL CO	230	230	K-FRAME	11.48	0.16	1		241	764,295	764,536				

	(K19;01) HARRINGTON STA								3-795 ACSR							
123	(K18-NM;01) ROOSEVELT CO INTG	TOLK STA	230	230	K-FRAME	11.18	0.00	1	3-795 ACSR	10,898	559,459	570,357				
124	(K18-TX;01) ROOSEVELT CO INTG	TOLK STA	230	230	K-FRAME	27.97	0.12	1	3-795 ACSR	32,221	3,783,747	3,815,968				
125	(K17;02) HARRINGTON STA	NICHOLS STA	230	230	K-FRAME	0.95	0.13	1	3-795 ACSS		41,452	41,452				
126	(K16;01) HARRINGTON STA	NICHOLS STA	230	230	H-FRAME	1.06	0.00	1	3-795 ACCC		121,547	121,547				
127	(K15;01) JONES PLANT	LUBBOCK EAST	230	230	TOWER	2.46	3.82	1	3-795 ACSR	40,416	722,252	762,668				
128	(K14;02) JONES PLANT	LUBBOCK SOUTH	230	230	TOWER	0.09	5.35	1	3-795 ACSR		281,393	281,393				
129	(K11;01) BUSHLAND	DEAF SMITH INTERCHANGE	230	230	K-FRAME	33.52	0.00	1	3-795 ACSR		2,218,317	2,218,317				
130	(K10;01) LUBBOCK SOUTH	WOLFFORTH INTG	230	230	H-FRAME	9.31	0.00	1	3-795 ACSR		1,431,356	1,431,356				
131	(K10;01) LUBBOCK SOUTH	WOLFFORTH INTG	230	230	K-FRAME	5.47	0.00	1	3-795 ACSR							
132	(K08;01) JONES PLANT	LUBBOCK SOUTH	230	230	TOWER	5.39	0.00	1	3-795 ACSR	98,926	1,230,605	1,329,531				
133	(K07;01) JONES PLANT	TUCO	230	230	K-FRAME	20.43	0.00	1	3-795 ACSR	205,589	3,808,638	4,014,227				
134	(K07;01) JONES PLANT	TUCO	230	230	TOWER	9.25	0.00	1	3-795 ACSR							
135	(K06;01) HUTCHINSON CO	NICHOLS STA	230	230	H-FRAME	1.05	0.00	1	3-795 ACSR	50,912	3,631,945	3,682,857				
136	(K06;01) HUTCHINSON CO	NICHOLS STA	230	230	K-FRAME	29.40	0.00	1	3-795 ACSR							
137	(K03;01) AMOCO SW. STA.	SUNDOWN SW. STA.	230	230	K-FRAME	5.31	0.00	1	3-795 ACSR	143,180	4,140,476	4,283,656				
138	(K02;01) SUNDOWN SW. STA.	WOLFFORTH INTG	230	230	H-FRAME	7.23	0.00	1	3-795 ACSR	177,182	5,246,699	5,423,881				
139	(K02;01) SUNDOWN SW. STA.	WOLFFORTH INTG	230	230	K-FRAME	17.35	0.00	1	3-795 ACSR							
140	(K01;01) SWISHER CO INTG	TUCO	230	230	K-FRAME	39.61	0.00	1	3-795 ACSR	908,602	12,817,687	13,726,289				
141	SUMMARY OF 115 KV SYSTEM		115	115	Overhead	3,127.21	251.08			63,819,320	797,463,636	861,282,956				
142	SUMMARY OF 115 KV SYSTEM		115	230	Overhead	4.06	0.00									
143	SUMMARY OF 115 KV SYSTEM		115	345	Overhead	0.16	0.00									
144			69	115	Overhead	44.21	4.19			3,712,807	190,287,234	194,000,041				

	SUMMARY OF 69 KV SYSTEM															
145	SUMMARY OF 69 KV SYSTEM		69	69	Overhead	1,136.49	282.85									
146	SUMMARY OF 69 KV SYSTEM		69	69	Underground	4.74	0.00									
36	TOTAL					7,369.21	600.20	139		157,656,368	2,118,496,165	2,276,152,533	850,989	862,996	1,668,125	3,382,110

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	(J27;01) CHINA DRAW	PHANTOM	20.22	H-FRAME	6	1	1	6-795	ACSS	26/7	345	1,709,591	18,458,593	5,219,441		25,387,624	
2	(J28;01) PHANTOM	ROADRUNNER	22.16	H-FRAME	6	1	1	6-795	ACSS	26/7	345	1,470,682	22,640,991	4,353,897		28,465,570	
3	(V50;01) BUSH	NORTHWEST INTG	0.35	H-FRAME	10	1	1	3-397.5	ACSR	26/7	115	67,305	520,365	590,508		1,178,178	
4	(U47;01) CANON WEST	TIERRA BLANCA	0.52	SINGLE POLE	10	1	1	3-477	ACSS	26/7	115			204,155		204,155	
5	(W51;01) CASTRO CO	NEWHART	0.02	3WAY NONSWITCH	36	1	1	3-397.5	ACSR	26/7	115	1,313,304	7,700,672	911,591		9,925,567	
6	(U48;01) CASTRO CO	TIERRA BLANCA	0.07	H-FRAME	30	1	1	3-397.5	ACSR	26/7	115			60,186		60,186	
7	(U42;01) DEAF SMITH INTERCHANGE	TIERRA BLANCA	0.46	SINGLE POLE	15	1	1	3-477	ACSS	26/7	115	37,586	1,109,851	119,136		1,266,574	
8	(U43;02) DEAF SMITH INTERCHANGE	TIERRA BLANCA	0.52	SINGLE POLE	11	1	1	3-477	ACSS	26/7	115	21,894	335,031	263,225		620,150	
9	(U46;01) HEREFORD NE	TIERRA BLANCA	0.13	H-FRAME	19	1	1	3-397.5	ACSR	26/7	115	19,115		172,982		192,098	
10	(U44;01) HEREFORD	TIERRA BLANCA	0.43	SINGLE POLE	13	1	1	3-397.5	ACSR	26/7	115	33,383	327,781	303,544		664,708	
11	(U45;02) HEREFORD	TIERRA BLANCA	0.32	SINGLE POLE	13	1	1	3-397.5	ACSR	26/7	115		405,759	113,458		519,217	
12	(U45;02) HEREFORD	TIERRA BLANCA	0.12	SINGLE POLE	13	1	1	3-397.5	ACSR	6/1	115						
13	(U38;01) LYNCH	MADDOX ST.	0.04	SINGLE POLE	15	1	1	3-336.4	ACSR	26/7	115		296,938	18,787		315,725	
14	(U39;01) LYNCH	QUAHADA	0.04	SINGLE POLE	12	1	1	3-336.4	ACSR	26/7	115		308,520	19,161		327,682	
15	(W25;01) OCOTILLO	PECOS	0.26	SINGLE POLE	25	1	1	3-397.5	ACSR	26/7	115		2,229,841	445,117		2,674,958	
16	(Z34;01) AMARILLO N. SW. STA.	NORTHWEST INTG	0.35	SINGLE POLE	12	1	1	3-Unknown	Unknown	Unknown	69		228	183,159		183,387	
17	(Y79;01) CO. LINE	TUCO	0.04	3WAY NONSWITCH	28	1	1	3-397.5	ACSR	26/7	69	288,030	4,450,402	3,408,428		8,146,860	
44	TOTAL		46.05		274	17	17					4,960,890	58,784,972	16,386,775		80,132,638	

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	3RD & WESTERN-T1	Distribution	Unattended	13.20	4.16		3.1	1				
2	8TH & BONHAM-T1	Distribution	Unattended	13.20	4.16		2.5	1				
3	8TH & BONHAM-T2	Distribution	Unattended	13.20	4.16		2.5	1				
4	ADAIR-T1	Distribution	Unattended	69.00	12.50		14.0	1				
5	ADOBE CREEK-T1	Distribution	Unattended	69.00	12.50		12.5	1				
6	ADOBE CREEK-T2	Distribution	Unattended	69.00	4.16		10.5	1				
7	AIKEN RURAL-T1	Distribution	Unattended	69.00	12.50		2.5	1				
8	ALLMON-T1	Distribution	Unattended	69.00	12.50		10.5	1				
9	ALLRED-T1	Distribution	Unattended	69.00	12.50		22.4	1				
10	AMARILLO SOUTH-T1	Transmission	Unattended	230.00	115.00	13.2	252.0	1				
11	AMFRAC-T1	Distribution	Unattended	115.00	2.40		7.5	1				
12	AMHERST-T1	Distribution	Unattended	69.00	2.40		3.75	1				
13	AMOCO YELLOWHOUSE-T1	Distribution	Unattended	69.00	12.50		3.0	1				
14	ANDREWS COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	168.0	1				
15	ANDREWS COUNTY-T2	Transmission	Unattended	230.00	115.00	13.2	168.0	1				
16	ANTON WEST-T1	Distribution	Unattended	69.00	12.50	12.5	2.0	1				
17	ARROWHEAD-T1	Distribution	Unattended	115.00	13.20		28.0	1				
18	ARTESIA 13TH STREET-T1	Distribution	Unattended	69.00	4.16		10.5	1				
19	ARTESIA CITY OR TOWN-T1	Distribution	Unattended	69.00	4.16		5.0	1				

20	ARTESIA COUNTRY CLUB-T1	Transmission	Unattended	12.50	69.00		12.5	1					
21	ARTESIA SOUTH-T1	Distribution	Unattended	69.00	12.50		14.0	1					
22	ARTESIA-T1	Transmission	Unattended	115.00	69.00		39.6	1					
23	ARTESIA-T2	Transmission	Unattended	115.00	69.00	13.2	39.6	1					
24	ATLANTIC-T1W,T1E,T1	Distribution	Unattended	23.00	2.40		0.5	3					
25	ATOKA-T1	Transmission	Unattended	115.00	69.00	13.2	39.6	1					
26	BAILEY COUNTY PUMP-T1	Distribution	Unattended	69.00	12.50		3.0	1					
27	BAILEY COUNTY-T1	Distribution	Unattended	69.00	12.50		0.5	1					
28	BAILEY COUNTY-T1E	Distribution	Unattended	69.00	12.50		0.5	1					
29	BAILEY COUNTY-T1W	Distribution	Unattended	69.00	12.50		0.5	1					
30	BAILEY COUNTY-T2	Transmission	Unattended	115.00	69.00		50.0	1					
31	BAILEY COUNTY-T3	Transmission	Unattended	115.00	69.00	13.2	50.0	1					
32	BAINER-T1W,T1E,T1	Distribution	Unattended	69.00	2.40		1.0	1					
33	BARWISE-T1	Distribution	Unattended	69.00	12.50		2.5	1					
34	BATTLE AXE-T1	Distribution	Unattended	115.00	13.20		50.0	1					
35	BATTLE AXE-T2	Distribution	Unattended	115.00	13.20		50.0	1					
36	BENNETT-T1	Distribution	Unattended	115.00	13.20		16.8	1					
37	BLACKHAWK-T1	Transmission	Unattended	115.00	69.00	13.2	75.0	1					
38	BLACKHAWK-T2	Transmission	Unattended	115.00	69.00	13.2	75.0	1					
39	BLODGETT-T1	Distribution	Unattended	12.50	2.40		3.0	1					
40	BOARDMAN-T1	Distribution	Unattended	69.00	12.50		224.0	1					
41	BOLTON PUMP-T1	Distribution	Unattended	12.50	2.40		3.75	1					
42	BONBRIGHT-T1	Distribution	Unattended	12.50	2.40		1.0	1					
43	BONBRIGHT-T2	Distribution	Unattended	12.50	2.40		0.1	1					
44	BOOKER-T1	Distribution	Unattended	69.00	34.50		7.5	1					
45	BOOKER-T2	Distribution	Unattended	69.00	4.16		3.75	1					
46	BORGER ISOM-T1	Distribution	Unattended	13.20	4.16		4.7	1					
47	BORGER NORTH-T1	Distribution	Unattended	12.50	4.16		3.8	1					
48	BORGER WEST-T1	Distribution	Unattended	115.00	13.20		28.0	1					
49	BOWERS-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
50	BOWERS-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
51	BOWERS-T3	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
52	BRASHER-T1	Distribution	Unattended	115.00	13.20		28.0	1					

53	BRISCOE COUNTY-T1	Distribution	Unattended	69.00	23.00		3.0	1				
54	BROWNFIELD SWITCHING-T1	Distribution	Unattended	69.00	23.00		6.3	1				
55	BUCKEYE-T1	Distribution	Unattended	115.00	12.50		12.5	1				
56	BUFFALO-T1	Distribution	Unattended	69.00	12.50		12.5	1				
57	BURNETT-T1	Distribution	Unattended	69.00	13.20		10.7	1				
58	BUSHLAND-T1	Transmission	Unattended	230.00	115.00	13.2	150.0	1				
59	BUSH-T1	Distribution	Unattended	115.00	13.80		28.0	1				
60	BYRD-T1	Distribution	Unattended	115.00	4.16		13.5	1				
61	CAMEX TRANSPETCO-T1	Distribution	Unattended	69.00	4.16		7.0	1				
62	CAMEX TRANSPETCO-T2	Distribution	Unattended	69.00	4.16		10.5	1				
63	CAMEX TRANSPETCO-T3	Distribution	Unattended	69.00	13.20		28.0	1				
64	CAMPBELL ST-T1	Distribution	Unattended	115.00	12.50		28.0	1				
65	CANADIAN-T1	Distribution	Unattended	69.00	4.16		12.5	1				
66	CANNON AFB-T1	Distribution	Unattended	115.00	13.20		0.3	1				
67	CANYON EAST-T1	Distribution	Unattended	115.00	13.20		28.0	1				
68	CANYON WEST-TR01	Distribution	Unattended	115.00	13.20		28.0	1				
69	CAPITAN-T1	Distribution	Unattended	115.00	13.20		28.0	1				
70	CARLISLE-T1	Transmission	Unattended	230.00	115.00	13.2	168.0	1				
71	CARLISLE-T2	Transmission	Unattended	115.00	69.00	13.2	39.5	1				
72	CARLISLE-T3	Distribution	Unattended	115.00	23.00		20.0	1				
73	CARLSBAD CAVERN-T1W,T1E,T1	Distribution	Unattended	12.50	2.40		0.25	3				
74	CARLSBAD WATERFIELD-T1	Distribution	Unattended	69.00	23.00		4.2	1				
75	CARLSBAD-T1	Transmission	Unattended	115.00	69.00	13.2	39.6	1				
76	CARLSBAD-T2	Transmission	Unattended	115.00	69.00		39.5	1				
77	CARLSBAD-T3	Distribution	Unattended	69.00	13.20		20.0	1				
78	CARSON CO-T1	Distribution	Unattended	115.00	13.80		12.5	1				
79	CASTRO COUNTY-T1	Transmission	Unattended	115.00	69.00		75.0	1				
80	CASTRO COUNTY-T2	Transmission	Unattended	115.00	69.00		75.0	1				
81	CEDAR LAKE EAST-T1W,T1E,T1	Distribution	Unattended	69.00	12.50		0.67	3				
82	CENTRE STREET-T1	Distribution	Unattended	69.00	13.20		25.0	1				
83	CHANNING-T1	Distribution	Unattended	230.00	34.50	19.9	28.0	1				
84	CHANNING-T2	Distribution	Unattended	230.00	34.50	19.9	28.0	1				
85	CHAVES COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				

86	CHAVES COUNTY-T2	Transmission	Unattended	230.00	115.00	13.2	252.0	1				
87	CHAVES COUNTY-T3	Transmission	Unattended	115.00	69.00		44.3	1				
88	CHERRY STREET-T1	Distribution	Unattended	115.00	13.20		28.0	1				
89	CHINADRAW-SVC	Transmission	Unattended	115.00	69.00		110.0	1				
90	CHINADRAW-TR01	Distribution	Unattended	115.00	13.20		28.0	1				
91	CHINADRAW-TR02	Distribution	Unattended	115.00	13.20		28.0	1				
92	CLIFFSIDE-T1	Distribution	Unattended	69.00	4.16		10.5	1				
93	CLOSE CITY-T1S,T1N,T1	Distribution	Unattended	23.00	2.40		0.6	3				
94	CLOVIS CITY-T1	Distribution	Unattended	23.00	4.16		6.0	1				
95	CLOVIS EAST-T1	Distribution	Unattended	115.00	13.20		28.0	1				
96	CLOVIS NORTH-T1	Distribution	Unattended	115.00	12.50		25.0	1				
97	CLOVIS PARK EAST-T1	Distribution	Unattended	23.00	4.16		6.0	1				
98	CLOVIS WEST-T1	Distribution	Unattended	115.00	13.20		28.0	1				
99	CLOVIS WEST-T2	Distribution	Unattended	69.00	23.00		22.4	1				
100	COBLE-T1	Distribution	Unattended	69.00	12.50		14.0	1				
101	COBURN CREEK-T1	Distribution	Unattended	115.00	13.20		28.0	1				
102	COCHRAN COUNTY-T1	Transmission	Unattended	115.00	69.00	13.2	40.0	1				
103	COCHRAN COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	40.0	1				
104	CONWAY-T1	Distribution	Unattended	115.00	13.20		22.4	1				
105	COOPER RANCH-T1	Distribution	Unattended	115.00	13.20		14.0	1				
106	CORTEZ-T1	Distribution	Unattended	115.00	4.16	2.4	5.0	1				
107	COTTONWOOD-T1	Distribution	Unattended	69.00	12.50		14.0	1				
108	COULTER-T1	Distribution	Unattended	115.00	13.80		25.0	1				
109	COULTER-T2	Transmission	Unattended	115.00	69.00		75.0	1				
110	COUNTY LINE-T1	Distribution	Unattended	69.00	12.50	2.4	18.75	1				
111	COX-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
112	CRMWA #1-T1	Distribution	Unattended	115.00	4.16		7.5	1				
113	CRMWA #22-T1	Distribution	Unattended	69.00	4.16		3.75	1				
114	CRMWA #23-T1	Distribution	Unattended	69.00	13.80		25.0	1				
115	CRMWA #2-T1	Distribution	Unattended	115.00	4.16		4.7	1				
116	CRMWA #3-T1	Distribution	Unattended	115.00	4.16		5.0	1				
117	CRMWA #4-T1	Distribution	Unattended	115.00	4.16		6.25	1				
118	CROSBY COUNTY INTERCHANGE-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				

119	CROSBY COUNTY INTERCHANGE-T2	Transmission	Unattended	115.00	69.00	13.2	39.6	1				
120	CROSBYTON-T1	Distribution	Unattended	23.00	4.16		6.25	1				
121	CROUSE-HINDS-T1	Distribution	Unattended	115.00	13.80		20.0	1				
122	CUNNINGHAM-T1	Transmission	Unattended	230.00	115.00	13.2	0.2	1				
123	CURRY COUNTY-T1	Distribution	Unattended	69.00	2.40		20.0	1				
124	CURRY COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	44.0	1				
125	CURRY COUNTY-T3	Transmission	Unattended	115.00	69.00	13.2	40.0	1				
126	DALHART-T1	Distribution	Unattended	69.00	2.40		4.7	1				
127	DALHART-T2	Transmission	Unattended	115.00	69.00	13.2	39.6	1				
128	DALHART-T3	Distribution	Unattended	69.00	12.50		22.4	1				
129	DALHART-T4	Distribution	Unattended	69.00	34.50		9.4	1				
130	DALLAM COUNTY-T1	Transmission	Unattended	115.00	69.00		39.6	1				
131	DAMRON-T1	Distribution	Unattended	69.00	13.20		10.0	1				
132	DAMRON-T2	Distribution	Unattended	13.20	2.40		5.0	1				
133	DARROUZETT-T1W,T1E,T1	Distribution	Unattended	34.50	4.16		0.33	3				
134	DAWN-T1	Distribution	Unattended	115.00	13.20		9.4	1				
135	DEAF SMITH-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
136	DEAF SMITH-T2	Transmission	Unattended	230.00	115.00	13.2	168.0	1				
137	DEAF SMITH-T3	Distribution	Unattended	115.00	13.80		8.0	1				
138	DENVER CITY EAST-T1	Distribution	Unattended	69.00	7.20		12.5	1				
139	DENVER CITY-T1	Transmission	Unattended	115.00	69.00	13.2	50.0	1				
140	DENVER CITY-T2	Transmission	Unattended	115.00	69.00	13.2	50.0	1				
141	DEXTER INTERCHANGE-T1	Distribution	Unattended	69.00	34.50		3.75	1				
142	DEXTER-T1	Distribution	Unattended	69.00	4.16		4.2	1				
143	DIAMONDBACK-T1	Transmission	Unattended	115.00	69.00	13.2	67.0	1				
144	DIEKEMPER-T1S,T1N,T1	Distribution	Unattended	69.00	4.16		0.5	3				
145	DIMMITT EAST-T1	Distribution	Unattended	69.00	13.20		20.0	1				
146	DIMMITT SOUTH-T1	Distribution	Unattended	69.00	12.50		14.0	1				
147	DOLLARHIDE-T1	Distribution	Unattended	115.00	12.50		22.4	1				
148	DOSS-T1	Distribution	Unattended	69.00	23.00		22.4	1				
149	DOSS-T2	Distribution	Unattended	69.00	12.50		20.0	1				
150	DOSS-T3	Transmission	Unattended	115.00	69.00		50.0	1				
151	DRINKARD-T1	Distribution	Unattended	115.00	12.50		22.4	1				

152	DUMAS 19TH STREET-T1	Distribution	Unattended	115.00	34.50		20.0	1				
153	DUMAS 19TH STREET-T2	Distribution	Unattended	115.00	12.50		28.0	1				
154	DUMAS EAST-T1	Distribution	Unattended	34.50	12.50		6.25	1				
155	DUMAS HELIUM-T1	Distribution	Unattended	34.50	12.50		3.8	1				
156	DUMAS NORTH-T1	Distribution	Unattended	34.50	2.40		6.3	1				
157	DUMAS SOUTH-T1	Distribution	Unattended	34.50	2.40		2.5	1				
158	EAGLE CREEK-T1	Transmission	Unattended	115.00	69.00	13.2	39.5	1				
159	EAST PLANT-T1	Distribution	Unattended	115.00	13.20		28.0	1				
160	EAST PLANT-T2	Transmission	Unattended	230.00	115.00	13.2	252.0	1				
161	EAST PLANT-T3	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
162	EAST PLANT-T4	Transmission	Unattended	115.00	69.00		84.0	1				
163	EAST PLANT-T5W,T5E,T5	Distribution	Unattended	13.20	2.40		2.4	3				
164	EAST SANGER-T1	Distribution	Unattended	115.00	12.50		22.4	1				
165	EDDY COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	168.0	1				
166	EDDY COUNTY-T2	Distribution	Unattended	230.00	8.50		100.0	1				
167	EDDY COUNTY-T3	Transmission	Unattended	345.00	230.00		560.0	1				
168	EDDY COUNTY-T4	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
169	EFDC GRAIN POWER PORTALES NM-T1	Distribution	Unattended	69.00	4.16		12.5	1				
170	ELBERT-T1S,T1N,T1	Distribution	Unattended	23.00	2.40		0.15	3				
171	ELLWOOD-T1	Distribution	Unattended	69.00	12.50		7.5	1				
172	ESTACADO-T1	Distribution	Unattended	115.00	13.20		28.0	1				
173	ESTACADO-T2	Distribution	Unattended	115.00	13.20		28.0	1				
174	ETTER RURAL-T1	Distribution	Unattended	115.00	34.50		20.0	1				
175	ETTER RURAL-T2	Distribution	Unattended	115.00	34.50		25.0	1				
176	EUNICE-T1	Distribution	Unattended	115.00	13.20		28.0	1				
177	EXELL-T1	Distribution	Unattended	115.00	12.50		12.5	1				
178	FAIN-T1	Distribution	Unattended	115.00	12.50		10.5	1				
179	FARMERS-T1	Distribution	Unattended	115.00	13.20		28.0	1				
180	FARWELL-T1	Distribution	Unattended	69.00	2.40		3.1	1				
181	FIESTA-T1	Distribution	Unattended	115.00	12.50		28.0	1				
182	FLANAGAN-T1	Distribution	Unattended	69.00	12.50		11.2	1				
183	FLOYD COUNTY-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
184	FLOYD COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	75.0	1				

185	FLOYDADA CITY-T1S,T1N,T1	Distribution	Unattended	23.00	2.40		1.0	3				
186	FLOYDADA CITY-T2S,T2N,T2	Distribution	Unattended	23.00	2.40		1.0	3				
187	FLOYDADA CITY-T3	Distribution	Unattended	24.00	13.80		0.75	1				
188	FLOYDADA SOUTH-T1	Distribution	Unattended	69.00	23.00		6.2	1				
189	FOLLETT-T1S,T1,T1N	Distribution	Unattended	34.50	4.16		1.0	2				
190	FRIONA CITY-T1	Distribution	Unattended	23.00	2.40		2.5	1				
191	FRIONA RURAL-T1	Distribution	Unattended	115.00	23.00		20.0	1				
192	FRITCH-T1	Distribution	Unattended	115.00	13.20		25.0	1				
193	GAINES COUNTY-T1	Transmission	Unattended	115.00	69.00	13.2	39.5	1				
194	GAINES COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	39.5	1				
195	GARZA-T1	Distribution	Unattended	69.00	23.00		6.0	1				
196	GARZA-T2	Distribution	Unattended	69.00	23.00		14.0	1				
197	GARZA-T3	Distribution	Unattended	69.00	2.40		5.0	1				
198	GOODPASTURE-T1S,T1N,T1	Distribution	Unattended	69.00	12.50		1.0	3				
199	GRAHAM-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
200	GRAHAM-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
201	GRAPEVINE-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
202	GRASSLAND-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
203	GRAY COUNTY-T1	Transmission	Unattended	115.00	69.00		75.0	1				
204	GREEN HEIGHTS-T1	Distribution	Unattended	12.50	2.40		1.5	1				
205	GRUVER-T1	Distribution	Unattended	34.50	12.50		3.5	1				
206	HAGERMAN TOWN-T1	Distribution	Unattended	23.00	4.16		1.75	1				
207	HAGERMAN WEST RURAL-T1	Distribution	Unattended	34.50	2.40		3.75	1				
208	HALE CENTER-T1	Distribution	Unattended	69.00	13.20		14.5	1				
209	HALE COUNTY-T1	Transmission	Unattended	115.00	69.00	13.2	40.0	1				
210	HALE COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	40.0	1				
211	HAPPY CITY-T1	Distribution	Unattended	69.00	12.50		6.0	1				
212	HAPPY-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
213	HAPPY-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
214	HARTLEY-T1S,T1N,T1	Distribution	Unattended	34.50	2.40		1.0	3				
215	HART-T1	Distribution	Unattended	115.00	13.20		14.0	1				
216	HASTINGS-T1	Distribution	Unattended	115.00	13.20		28.0	1				
217	HENDRICKS-T1	Distribution	Unattended	69.00	23.00		12.5	1				

218	HEREFORD CITY-T1	Distribution	Unattended	69.00	13.80		20.0	1					
219	HEREFORD NORTH EAST-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
220	HEREFORD NORTH EAST-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
221	HEREFORD SOUTH-T1	Transmission	Unattended	115.00	69.00		39.6	1					
222	HEREFORD-T1	Transmission	Unattended	115.00	69.00	13.2	39.6	1					
223	HERRING-T1	Distribution	Unattended	115.00	34.50		16.8	1					
224	HIGG EAST-T1	Distribution	Unattended	115.00	13.20		28.0	1					
225	HIGGINS-T1W,T1E,T1	Distribution	Unattended	34.50	4.16		1.5	3					
226	HIGHLAND PARK-T1	Distribution	Unattended	115.00	13.80		46.7	1					
227	HITCHLAND-T1	Transmission	Unattended	345.00	230.00		560.0	1					
228	HITCHLAND-T2	Transmission	Unattended	230.00	115.00	13.2	250.0	1					
229	HITCHLAND-T3	Transmission	Unattended	345.00	230.00		560.0	1					
230	HOBBS GENERATING-T1	Transmission	Unattended	230.00	115.00	13.2	150.0	1					
231	HOBBS GENERATING-T2	Transmission	Unattended	230.00	115.00	13.2	200.0	1					
232	HOBBS NE-T1	Distribution	Unattended	115.00	12.50		28.0	1					
233	HOBBS NORTH-T1	Distribution	Unattended	115.00	12.50		22.4	1					
234	HOBBS NORTH-T2	Distribution	Unattended	115.00	12.50		28.0	1					
235	HOBBS SOUTH-T1	Distribution	Unattended	115.00	12.50		22.4	1					
236	HOBBS SOUTH-T2	Distribution	Unattended	115.00	13.20		22.4	1					
237	HOBGOOD-T1S,T1N,T1	Distribution	Unattended	69.00	2.40		2.25	3					
238	HOCKLEY COUNTY-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
239	HOCKLEY COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
240	HOPI-T1	Distribution	Unattended	115.00	13.20		28.0	1					
241	HOWARD-T1	Distribution	Unattended	115.00	13.20		14.0	1					
242	HOWARD-T2	Transmission	Unattended	115.00	69.00	13.2	39.5	1					
243	HOWARD-T3	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
244	HUTCHINSON COUNTY-T1	Transmission	Unattended	115.00	69.00		75.0	1					
245	HUTCHINSON COUNTY-T2	Transmission	Unattended	230.00	115.00	13.2	150.0	1					
246	HUTCHINSON COUNTY-T3	Transmission	Unattended	230.00	115.00	13.2	150.0	1					
247	HVDC TIE-T2	Transmission	Unattended	230.00	115.00		272.0	1					
248	HVDC TIE-T3	Distribution	Unattended	345.00	34.50		273.0	1					
249	IDALOU-T1	Distribution	Unattended	23.00	4.16		1.5	1					
250	IMC #4-T1	Distribution	Unattended	69.00	13.20		7.0	1					

251	INDUSTRIAL-T1	Distribution	Unattended	69.00	13.20		20.0	1				
252	INK BASIN-TR1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
253	JAL-T1	Distribution	Unattended	115.00	13.80		20.0	1				
254	JAYBEE-T1	Distribution	Unattended	69.00	12.50		5.0	1				
255	KERRICK PUMP-T1S,T1N,T1	Distribution	Unattended	34.50	2.40		1.5	3				
256	KILGORE-T1	Distribution	Unattended	115.00	13.20		14.0	1				
257	KINGSMILL-T1	Distribution	Unattended	115.00	12.50	15.0	75.0	1				
258	KINGSMILL-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
259	KINGSMILL-T3	Distribution	Unattended	69.00	13.80		20.0	1				
260	KINNEY-T1W,T1E,T1	Distribution	Unattended	69.00	2.40		1.0	3				
261	KISER-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
262	KITE-T1	Distribution	Unattended	69.00	13.20		22.4	1				
263	KRESS RURAL-T1	Distribution	Unattended	115.00	13.20		14.0	1				
264	KRESS-T1	Transmission	Unattended	115.00	69.00	13.2	56.0	1				
265	LAKE MEREDITH-T1	Distribution	Unattended	115.00	4.16		10.0	1				
266	LAMB COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	252.0	1				
267	LAMB COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	75.0	1				
268	LAMB COUNTY-T3	Transmission	Unattended	115.00	69.00	13.2	75.0	1				
269	LAMTON-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
270	LARIAT-T1	Distribution	Unattended	69.00	12.50		3.1	1				
271	LAWRENCE PARK-T1	Distribution	Unattended	69.00	13.80		28.0	1				
272	LAWRENCE PARK-T2	Distribution	Unattended	69.00	13.80		28.0	1				
273	LEA NATIONAL-T1	Distribution	Unattended	115.00	12.50		14.0	1				
274	LEA ROAD-T1	Distribution	Unattended	115.00	12.50		12.5	1				
275	LEGACY-T1	Transmission	Unattended	115.00	69.00	13.2	50.0	1				
276	LEHMAN-T1	Distribution	Unattended	115.00	12.50		20.0	1				
277	LEVELLAND CITY-T1	Distribution	Unattended	69.00	12.50		22.4	1				
278	LEVELLAND CITY-T2W,T2E,T2	Distribution	Unattended	12.50	2.40		2.1	3				
279	LEVELLAND CITY-T3W,T3E,T3	Distribution	Unattended	69.00	2.40		1.8	3				
280	LEVELLAND EAST-T1	Distribution	Unattended	69.00	12.50		22.4	1				
281	LIPSCOMB CO-T1	Distribution	Unattended	115.00	34.50		28.0	1				
282	LIPSCOMB CO-T2	Distribution	Unattended	115.00	13.20		7.0	1				
283	LITTLEFIELD CITY-T1	Distribution	Unattended	69.00	4.16		0.5	1				

284	LITTLEFIELD SOUTH-T1	Distribution	Unattended	69.00	12.50		7.5	1				
285	LITTLEFIELD WEST-T1	Distribution	Unattended	69.00	12.50		0.5	1				
286	LITTLEFIELD WEST-T1W,T1E	Distribution	Unattended	69.00	7.20		0.5	2				
287	LIVINGSTON RIDGE-T1	Distribution	Unattended	69.00	12.50		28.0	1				
288	LOCKNEY CITY-T1	Distribution	Unattended	23.00	12.50		2.5	1				
289	LOCKNEY RURAL-T1	Distribution	Unattended	69.00	23.00		14.0	1				
290	LOCKNEY RURAL-T2W,T2E,T2	Distribution	Unattended	69.00	12.50		2.5	3				
291	LOCKNEY WEST-T1	Distribution	Unattended	23.00	7.20		3.0	1				
292	LORENZO-T1	Distribution	Unattended	23.00	4.16		1.5	1				
293	LOVING SOUTH-T1	Distribution	Unattended	69.00	13.20		28.0	1				
294	LUBBOCK EAST-T1	Transmission	Unattended	230.00	115.00	13.2	150.0	1				
295	LUBBOCK EAST-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
296	LUBBOCK EAST-T3	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
297	LUBBOCK SOUTH-T1	Transmission	Unattended	230.00	115.00	13.2	252.0	1				
298	LUBBOCK SOUTH-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
299	LUBBOCK SOUTH-T3	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
300	LYNCH-TR1	Transmission	Unattended	115.00	69.00		84.0	1				
301	LYNN COUNTY-T1	Transmission	Unattended	115.00	69.00	13.2	39.5	1				
302	LYNN COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	27.0	1				
303	LYNN COUNTY-T3	Distribution	Unattended	115.00	23.00		14.0	1				
304	LYONS-T1	Distribution	Unattended	69.00	13.80		20.0	1				
305	MADANOS-TR1	Distribution	Unattended	115.00	22.80		50.0	1				
306	MAGNOLIA PUMP STATION-T1	Distribution	Unattended	24.00	2.40		2.5	1				
307	MALAGA BEND-TR1	Distribution	Unattended	115.00	12.40		28.0	1				
308	MALAGA BEND-TR2	Distribution	Unattended	115.00	22.80		50.0	1				
309	MALJAMAR #1-T1	Distribution	Unattended	115.00	12.50		14.0	1				
310	MALJAMAR 2-T1	Distribution	Unattended	115.00	12.50		12.5	1				
311	MANHATTAN-T1	Distribution	Unattended	115.00	13.20		25.0	1				
312	MARKET STREET-T1	Distribution	Unattended	69.00	12.50		12.5	1				
313	MCCLELLAN PUMP-T1	Distribution	Unattended	115.00	13.20		10.5	1				
314	MCCULLOUGH-T1	Distribution	Unattended	69.00	13.20		25.0	1				
315	MCLEAN RURAL-T1	Distribution	Unattended	115.00	13.20		9.4	1				
316	MID AMERICA #3-T1	Distribution	Unattended	69.00	2.40		5.0	1				

317	MID-AMERICA #2-T1	Distribution	Unattended	69.00	2.40		3.75	1				
318	MIDDLETON-T1	Distribution	Unattended	69.00	12.50		14.0	1				
319	MILLEN-T1	Distribution	Unattended	115.00	7.20		22.4	1				
320	MITCHELL STREET-T1	Distribution	Unattended	23.00	4.16		5.0	1				
321	MONROE-T1	Distribution	Unattended	69.00	23.00		10.0	1				
322	MONUMENT-T1	Distribution	Unattended	115.00	12.50		28.0	1				
323	MOORE COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	225.0	1				
324	MOORE COUNTY-T2	Distribution	Unattended	115.00	13.20		16.8	1				
325	MORTON-T1	Distribution	Unattended	69.00	4.16		5.0	1				
326	MOSS-T1	Distribution	Unattended	69.00	23.00		10.0	1				
327	MULESHOE VALLEY-T1	Distribution	Unattended	115.00	13.20		14.0	1				
328	MULESHOE WEST-T1	Distribution	Unattended	69.00	12.50		14.0	1				
329	MURPHY-T1	Distribution	Unattended	115.00	23.00		50.0	1				
330	MUSTANG-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
331	NAVAJO #1-T1	Distribution	Unattended	69.00	2.40		7.5	1				
332	NAVAJO #2-T1	Distribution	Unattended	115.00	4.16		22.4	1				
333	NAVAJO #3-T1	Distribution	Unattended	115.00	4.16		22.4	1				
334	NAVAJO #4-T1	Distribution	Unattended	69.00	2.40		22.4	1				
335	NAVAJO #5-T1	Distribution	Unattended	115.00	4.16		22.4	1				
336	NAVAJO-MALAGA-T1	Distribution	Unattended	69.00	4.16		10.5	1				
337	NEWHART-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
338	NICHOLS-T7	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
339	NICHOLS-T8	Transmission	Unattended	230.00	115.00	13.2	150.0	1				
340	NM POTASH #2-T1	Distribution	Unattended	69.00	13.80		10.5	1				
341	NORRIS ST-T1	Distribution	Unattended	115.00	13.20		22.4	1				
342	NORTH CANAL-T1	Distribution	Unattended	115.00	12.50		28.0	1				
343	NORTH LOVING-T1	Distribution	Unattended	115.00	13.20		28.0	1				
344	NORTHWEST-T1	Transmission	Unattended	115.00	69.00		84.0	1				
345	OASIS-T1	Transmission	Unattended	230.00	115.00	13.2	225.0	1				
346	OCHILTREE-T1	Transmission	Unattended	230.00	115.00		168.0	1				
347	OCHOA-T1	Distribution	Unattended	115.00	13.20		28.0	1				
348	OCOTILLO-T1	Distribution	Unattended	115.00	13.20		28.7	1				
349	OLTON-T1	Distribution	Unattended	69.00	7.20		7.5	1				

350	ONG-T1	Distribution	Unattended	13.20	4.16		3.75	1				
351	OSAGE PUMP-T1W,T1E,T1	Distribution	Unattended	13.20	2.40		2.5	3				
352	OSAGE PUMP-T2S,T2N,T2	Distribution	Unattended	13.20	2.40		2.5	3				
353	OSAGE-T1	Distribution	Unattended	115.00	13.20		28.0	1				
354	OWENS-CORNING-T1	Distribution	Unattended	115.00	13.80		25.0	1				
355	OWENS-CORNING-T2	Distribution	Unattended	115.00	13.80		25.0	1				
356	PACIFIC-T1	Distribution	Unattended	115.00	12.50		22.4	1				
357	PALO DURO-T1	Distribution	Unattended	115.00	13.20		7.5	1				
358	PARMER COUNTY-T1	Distribution	Unattended	115.00	23.00		7.5	1				
359	PCA-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
360	PCA-T2	Distribution	Unattended	69.00	13.20		22.4	1				
361	PEARL-T1	Distribution	Unattended	115.00	12.50		5.0	1				
362	PECOS-T1	Transmission	Unattended	230.00	115.00		168.0	1				
363	PECOS-T2	Distribution	Unattended	115.00	13.20		28.0	1				
364	PERIMETER-T1	Distribution	Unattended	115.00	13.20		27.4	1				
365	PERRYTON-T1	Distribution	Unattended	115.00	12.50		12.0	1				
366	PERRYTON-T4S,T4N,T4	Transmission	Unattended	115.00	69.00		6.3	3				
367	PHILLIPS PUMP #1-T1	Distribution	Unattended	69.00	2.40		2.5	1				
368	PHILLIPS PUMP #2-T1	Distribution	Unattended	69.00	2.40		2.5	1				
369	PIERCE STREET-T1	Distribution	Unattended	115.00	13.20		28.0	1				
370	PLAINVIEW CITY-T1W,T1E,T1,T1	Distribution	Unattended	69.00	2.40		1.25	3				
371	PLAINVIEW CITY-T2W,T2E,T2	Distribution	Unattended	69.00	2.40		1.25	3				
372	PLAINVIEW EAST-T1	Distribution	Unattended	69.00	12.50		22.4	1				
373	PLAINVIEW NORTH-T1	Distribution	Unattended	115.00	13.20		14.0	1				
374	PLAINVIEW SOUTH-T1	Distribution	Unattended	69.00	12.50		14.0	1				
375	PLAINVIEW WESTRIDGE-T1	Distribution	Unattended	69.00	7.20		22.4	1				
376	PLAINVIEW WEST-T1	Distribution	Unattended	69.00	12.50		22.4	1				
377	PLANT X-T1	Transmission	Unattended	230.00	115.00	13.2	252.0	1				
378	PLANT X-T19	Distribution	Unattended	115.00	12.50		6.25	1				
379	PLEASANT HILL-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
380	PORTALES #1-T1	Distribution	Unattended	69.00	4.16		7.5	1				
381	PORTALES #2-T1	Distribution	Unattended	69.00	12.50	7.2	14.0	1				
382	PORTALES #2-T2	Distribution	Unattended	69.00	4.16		6.8	1				

383	PORTALES INTERCHANGE-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
384	PORTALES INTERCHANGE-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
385	PORTALES WATERFIELD-T1	Distribution	Unattended	115.00	13.20		12.5	1				
386	POTASH JUNCTION-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
387	POTASH JUNCTION-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
388	POTASH JUNCTION-T3	Transmission	Unattended	115.00	69.00	13.2	84.0	1				
389	POTTER COUNTY-T1	Transmission	Unattended	345.00	230.00	13.2	500.0	1				
390	POTTER COUNTY-T2	Transmission	Unattended	230.00	115.00		252.0	1				
391	POTTER COUNTY-T3	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
392	PRENTICE-T1	Distribution	Unattended	115.00	12.50		28.0	1				
393	PRICE-T1	Distribution	Unattended	69.00	12.50		25.0	1				
394	PRINGLE OIL FIELD-T1	Distribution	Unattended	34.50	12.50		28.0	1				
395	PRINGLE-T1	Transmission	Unattended	230.00	115.00	13.2	225.0	1				
396	PRINGLE-T2	Distribution	Unattended	115.00	34.50		28.0	1				
397	PUCKETT WEST-T1	Distribution	Unattended	115.00	13.20		25.0	1				
398	PULLMAN-T1	Distribution	Unattended	115.00	13.20		25.0	1				
399	RALLS-T1W,T1E,T1	Distribution	Unattended	23.00	2.40		2.5	3				
400	RANDALL COUNTY-T1	Distribution	Unattended	230.00	13.20		225.0	1				
401	RANDALL COUNTY-T2	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
402	RILEY-T1	Distribution	Unattended	69.00	7.20		7.5	1				
403	RIVERVIEW-T2	Distribution	Unattended	115.00	13.20		25.0	1				
404	RIVERVIEW-T3	Transmission	Unattended	115.00	69.00		39.5	1				
405	ROADRUNNER-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
406	ROADRUNNER-T2 SVC	Transmission	Unattended	345.00	115.00	13.2	448.0	1				
407	ROADRUNNER-TR3	Distribution	Unattended	115.00	22.86		50.0	1				
408	ROBERTS COUNTY-T1 NEW	Distribution	Unattended	69.00	7.20		6.25	1				
409	ROLLING HILLS-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
410	ROOSEVELT COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	252.0	1				
411	ROSWELL CITY-T1	Distribution	Unattended	115.00	13.20		28.0	1				
412	ROSWELL CITY-T2	Distribution	Unattended	115.00	13.20		28.0	1				
413	ROSWELL-T1	Transmission	Unattended	115.00	69.00	13.2	40.0	1				
414	ROSWELL-T2	Transmission	Unattended	115.00	69.00	13.2	39.5	1				
415	ROUND UP-T1S,T1N,T1	Distribution	Unattended	13.20	2.40		0.25	3				

416	ROXANNA-T1	Distribution	Unattended	69.00	13.20		14.0	1				
417	RUSSELL POOL-T1	Distribution	Unattended	115.00	12.50		12.0	1				
418	RUSSELL POOL-T2	Distribution	Unattended	115.00	13.20		25.0	1				
419	SAGE BRUSH-T1	Distribution	Unattended	115.00	23.00		50.0	1				
420	SAMSON-T1	Distribution	Unattended	115.00	12.50		22.4	1				
421	SAN JACINTO-T1S,T1N,T1	Distribution	Unattended	13.20	2.40		2.5	3				
422	SAND DUNES-T1	Distribution	Unattended	115.00	13.20		28.0	1				
423	SEAGRAVES INTERCHANGE-T1	Transmission	Unattended	115.00	69.00	13.2	75.0	1				
424	SEMINOLE CITY-T1	Distribution	Unattended	23.00	2.40		2.5	1				
425	SEMINOLE INTG-T1	Transmission	Unattended	230.00	115.00	13.2	150.0	1				
426	SEMINOLE INTG-T2	Transmission	Unattended	230.00	115.00	13.2	150.0	1				
427	SEMINOLE INTG-T3	Distribution	Unattended	115.00	23.00		28.0	1				
428	SEVEN RIVERS-T1	Transmission	Unattended	115.00	69.00	13.2	44.4	1				
429	SEVEN RIVERS-T2	Transmission	Unattended	230.00	115.00	13.8	150.0	1				
430	SHALLOWATER-T1S,T1N,T1	Distribution	Unattended	23.00	2.40		0.3	3				
431	SHAMROCK PUMP-T1S,T1N,T1	Distribution	Unattended	69.00	2.40		1.5	3				
432	SHELL C2 COMPRESSOR-T1	Distribution	Unattended	115.00	4.16		12.5	1				
433	SHELL C3-T1	Distribution	Unattended	115.00	12.50		12.5	1				
434	SHERMAN COUNTY-T1	Distribution	Unattended	115.00	34.50		20.0	1				
435	SILVERTON CITY-T1	Distribution	Unattended	23.00	2.40		1.5	1				
436	SLATON-T1	Distribution	Unattended	69.00	23.00		14.0	1				
437	SLATON-T2	Distribution	Unattended	69.00	4.16		3.8	1				
438	SLAUGHTER-T1	Distribution	Unattended	69.00	2.40		3.75	1				
439	SMITH-T1	Distribution	Unattended	69.00	4.16		4.7	1				
440	SNEED-T1	Distribution	Unattended	34.50	12.50		4.2	1				
441	SONCY-T1	Distribution	Unattended	69.00	13.80		37.3	1				
442	SOUTH GEORGIA-T1	Transmission	Unattended	115.00	69.00		84.0	1				
443	SOUTH GEORGIA-T2	Distribution	Unattended	115.00	13.80		25.0	1				
444	SOUTH GEORGIA-T3	Distribution	Unattended	115.00	12.50		28.0	1				
445	SOUTH PLAINS-T1W,T1E,T1	Distribution	Unattended	23.00	4.16		0.75	3				
446	SOUTHEAST-T1	Distribution	Unattended	115.00	13.20		28.0	1				
447	SOUTHLAND-T1S,T1N,T1	Distribution	Unattended	69.00	2.40		1.5	3				
448	SPEARMAN CITY-T1	Transmission	Unattended	115.00	69.00	13.2	10.5	1				

449	SPEARMAN CITY-T2	Distribution	Unattended	115.00	4.16		10.5	1					
450	SPEARMAN INTG-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
451	SPEARMAN INTG-T2	Distribution	Unattended	69.00	34.50		12.5	1					
452	SPRING CREEK-T1	Distribution	Unattended	69.00	13.80		9.4	1					
453	SPRING DRAW-T1	Distribution	Unattended	115.00	13.20		28.0	1					
454	SPRINGLAKE-T1	Distribution	Unattended	69.00	12.50		7.5	1					
455	STINNETT-T1	Distribution	Unattended	34.50	12.50		6.3	1					
456	STRATA-T1	Distribution	Unattended	69.00	12.50		28.0	1					
457	STRATFORD-T1	Distribution	Unattended	34.50	2.40		3.1	1					
458	STRATFORD-T2	Distribution	Unattended	34.50	12.50		3.75	1					
459	SUDAN RURAL-T1	Distribution	Unattended	69.00	12.50		5.3	1					
460	SULPHUR SPRINGS-T1	Transmission	Unattended	115.00	69.00	13.2	44.8	1					
461	SULPHUR SPRINGS-T2	Transmission	Unattended	115.00	69.00	13.2	44.8	1					
462	SUNDOWN-T1	Transmission	Unattended	230.00	115.00	13.2	100.0	1					
463	SUNRAY-T1W,T1E,T1	Distribution	Unattended	34.50	7.20		2.5	3					
464	SUNSET-T1	Distribution	Unattended	115.00	13.20		25.0	1					
465	SUNSET-T2	Distribution	Unattended	115.00	13.20		28.0	1					
466	SWISHER COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1					
467	TAHOKA CITY-T1	Distribution	Unattended	23.00	2.40		2.5	1					
468	TASCOSA-T1	Distribution	Unattended	34.50	13.20		7.0	1					
469	TEAGUE-T1	Distribution	Unattended	115.00	12.50		14.0	1					
470	TENNECO-T1	Distribution	Unattended	69.00	12.50		7.0	1					
471	TERRY COUNTY-T1	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
472	TERRY COUNTY-T2	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
473	TEXACO-T1	Distribution	Unattended	69.00	12.50		20.0	1					
474	TEXAS FARMS-T1	Distribution	Unattended	115.00	13.20		9.4	1					
475	TOKIO-T1	Distribution	Unattended	69.00	12.50		6.25	1					
476	TOLK-T1	Transmission	Unattended	345.00	230.00	13.2	560.0	1					
477	TUCO-T1	Transmission	Unattended	345.00	230.00	13.2	560.0	1					
478	TUCO-T12	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
479	TUCO-T2	Transmission	Unattended	230.00	115.00	13.2	252.0	1					
480	TUCO-T3	Transmission	Unattended	115.00	69.00	13.2	84.0	1					
481	TUCO-T4	Transmission	Unattended	115.00	69.00	13.2	84.0	1					

482	TUCO-T5	Distribution	Unattended	69.00	12.50		13.3	1				
483	TUCO-T6 SVC	Distribution	Unattended	230.00	13.20		90.0	1				
484	TUCO-T7	Transmission	Unattended	230.00	115.00		225.0	1				
485	TUCO-T8	Transmission	Unattended	345.00	230.00	13.2	560.0	1				
486	TWEEDY-T1	Distribution	Unattended	115.00	13.20		22.4	1				
487	UNITED SALT-T1	Distribution	Unattended	69.00	12.50		0.75	1				
488	URTON-T1	Distribution	Unattended	115.00	13.20		22.4	1				
489	VAN BUREN-T1	Distribution	Unattended	69.00	13.20		25.0	1				
490	VAN BUREN-T2	Distribution	Unattended	69.00	13.20		25.0	1				
491	VEGA-T1	Distribution	Unattended	69.00	13.20		14.0	1				
492	VICKERS-T1	Distribution	Unattended	69.00	23.00		14.0	1				
493	WADE-T1	Distribution	Unattended	115.00	13.20		7.0	1				
494	WARD-T1	Distribution	Unattended	115.00	12.50		5.3	1				
495	WASSON-T1	Distribution	Unattended	69.00	2.40		2.3	1				
496	WAVERLY-T1	Distribution	Unattended	23.00	4.16		3.6	1				
497	WEATHERLY-T1	Distribution	Unattended	69.00	13.80		14.0	1				
498	WELLMAN-T1	Distribution	Unattended	69.00	12.50		5.0	1				
499	WEST BENDER-T1	Distribution	Unattended	115.00	7.20		22.4	1				
500	WESTERN STREET-T1	Distribution	Unattended	115.00	13.20		22.4	1				
501	WHEELER COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
502	WHITAKER-T1	Distribution	Unattended	115.00	13.80		25.0	1				
503	WHITE CITY-T1	Distribution	Unattended	7.20	2.40		2.8	1				
504	WHITEFACE-T1	Distribution	Unattended	69.00	12.50		14.0	1				
505	WHITEHEAD-T1	Distribution	Unattended	69.00	4.16		3.7	1				
506	WHITHARREL-T1	Distribution	Unattended	69.00	4.16		2.5	1				
507	WHITTEN-T1	Distribution	Unattended	115.00	12.50		12.5	1				
508	WILDORADO-T1	Distribution	Unattended	69.00	12.50		13.0	1				
509	WILLS OIL-T1E, T1	Distribution	Unattended	69.00	7.20		1.0	2				
510	WILLS OIL-T1W	Distribution	Unattended	69.00	12.50		0.7	1				
511	WILSON-T1	Distribution	Unattended	23.00	2.40		0.75	1				
512	WIPP-T1	Distribution	Unattended	115.00	13.80		22.4	1				
513	WIPP-T2	Distribution	Unattended	115.00	13.80		22.4	1				
514	WOLFFORTH-T1	Transmission	Unattended	230.00	115.00	13.2	168.0	1				

515	WOODDRAW-T1	Distribution	Unattended	115.00	13.20		28.0	1				
516	XIT-T1	Transmission	Unattended	230.00	115.00	13.2	250.0	1				
517	YANCY-T1	Distribution	Unattended	69.00	2.40		2.3	1				
518	YOAKUM COUNTY-T1	Transmission	Unattended	230.00	115.00	13.2	150.0	1				
519	YOAKUM COUNTY-T2	Transmission	Unattended	230.00	115.00	13.2	150.0	1				
520	ZAVALLA-T1	Distribution	Unattended	69.00	12.50		12.5	1				
521	ZIA-T1	Distribution	Unattended	115.00	13.20		12.5	1				
522	522						27901	589				
523	Spare Transformers											
524	10 MVA MOBILE-T1			69.00	13.20		10		1			
525	16 MVA MOBILE-T1			69.00	12.50		16		1			
526	20 MVA NEW MOBILE-T1			115.00	25.00		20		1			
527	20 MVA OLD MOBILE-T1			115.00	25.00		20		1			
528	3 MVA MOBILE-T1			25.00	12.50		3		1			
529	56 MVA MOBILE			115.00	69.00	13.2	56		1			
530	Chaves-			230.00	115.00		150		1			
531	Clovis Yard-			69.00	5.00		3.75		1			
532	Clovis Yard-SHT-5301-0101			69.00	5.00		7		1			
533	EAST PLANT-201741			115.00	5.00		5.6		1			
534	EAST PLANT-207971			69.00	35.00		20		1			
535	EAST PLANT-2720511			35.00	13.00		10.5		1			
536	EAST PLANT-3461025			35.00	13.00		5.25		1			
537	EAST PLANT-58224618211			115.00	14.00		20		1			
538	EAST PLANT-6151201			69.00	13.00		6.25		1			
539	EAST PLANT-6352677			14.00	2.50		2.80		1			
540	EAST PLANT-7018874			13.00	5.00		3.5		1			
541	EAST PLANT-86201			35.00	13.00		0.75		1			
542	EAST PLANT-9405401326			69.00	35.00		6.25		1			
543	EAST PLANT-C4234411			69.00	5.00		8.40		1			
544	EAST PLANT-C500502			69.00	25.00		6.25		1			
545	EAST PLANT-M16218813			69.00	13.00		28		1			
546	FOLLETT-3330738			35.00	7.50		0.333		1			
547	Harrington Poleyard-5352PH099			230.00	115.00	13	250		1			

548	Harrington Poleyard-8727009			345.00	230.00		560		1			
549	Harrington Poleyard-E4468			115.00	69.00	13	84		1			
550	Harrington Poleyard-E4469			115.00	69.00	13	84		1			
551	Hobbs Gen-LLL5856-2			230.00	138.00	13	150		1			
552	Navajo #4 Yard- B313935			69.00	5.00		5		1			
553	North Subs Opns-			35.00	5.00		3.75		1			
554	North Subs Opns-			25.00	5.00		3.75		1			
555	North Subs Opns-			14.00	5.00		3.75		1			
556	Plainview City-8976856			69.00	2.50		1.25		1			
557	RIVERVIEW PLANT-1699300			14.00	2.50		2		1			
558	RIVERVIEW PLANT-26038-1			13.00	2.50		2.30		1			
559	RIVERVIEW PLANT-921156			35.00	13.00		3.12		1			
560	RIVERVIEW PLANT-C-859906			35.00	2.50		1.725		1			
561	XFMR SPARE (RoadRunner)			345.00	115.00		448		1			
562	Spare 1 50MVA 25KV Sage Brush			115.00	22.80		50		1			
563	Total								39			0

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Emergency assistance - sale of natural gas	Public Service Co. of Colorado	[a] see note	28,293,522
3	Services provided by Xcel Energy Services, Inc.	Xcel Energy Services Inc.	[b] see note	
4	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services	233	(539,000,000)
5	Repayments from Utility Money Pool Arrangement	Xcel Energy Services	145	(83,000,000)
6	Capital Contributions from Parent	Xcel Energy, Inc.	207	(304,043,207)
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Company labor, benefits, and related payments	Public Service Co. of Colorado	[c] see note	(319,164)
22	Investment in Utility Money Pool Arrangement	Xcel Energy Services	145	83,000,000
23	Repayment under Utility Money Pool Arrangement	Xcel Energy Services	233	561,000,000
24	Dividends on Common Stock	Xcel Energy, Inc.	438	310,172,000
42				

Name of Respondent: Southwestern Public Service Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 05/24/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

151	$	1,246,160
E501		14,252,862
E547		2,315,621
E555		10,478,879
		28,293,522

(b) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Service Function Group	Updated FERC Group		Total
Accounting, Financial Reporting & Taxes	107-CWIP	$	8,653
	181-190-Deferred Debits		(21,936)
	408-409-Taxes		10,824
	417-421-Other Income		(1,041,606)
	426.1-426.5-Other Income Deductions		28,086
	427-432-Interest Charges		44,332
	500-514-Steam Power Generation		141,893
	546-557-Other Power Generation		(6,724)
	560-573-Transmission Expenses		(125)
	580-598-Distribution Expenses		44,405
	920-935-Administrative and General Expense		11,061,522
Accounting, Financial Reporting & Taxes Total			10,269,324
Aviation Services	426.1-426.5-Other Income Deductions		5
	920-935-Administrative and General Expense		502,638
Aviation Services Total			502,643
Business Systems	107-CWIP		36,070,004
	130-176-Current and Accrued Assets		37

	181-190-Deferred Debits	475
	408-409-Taxes	7
	417-421-Other Income	3
	426.1-426.5-Other Income Deductions	18,828
	500-514-Steam Power Generation	778,583
	546-557-Other Power Generation	59,178
	560-573-Transmission Expenses	2,470,037
	580-598-Distribution Expenses	972,703
	901-905-Customer Accounts Expenses	2,894,442
	908-910-Customer Service and Informational Expenses	7
	911-916-Sales Expense	2
	920-935-Administrative and General Expense	40,424,360
Business Systems Total		83,688,666
Claims Services	426.1-426.5-Other Income Deductions	10
	920-935-Administrative and General Expense	173,331
Claims Services Total		173,341
Corporate Communications	181-190-Deferred Debits	310,899
	426.1-426.5-Other Income Deductions	15,158
	908-910-Customer Service and Informational Expenses	72,884
	911-916-Sales Expense	13
	920-935-Administrative and General Expense	974,037
Corporate Communications Total		1,372,991
Corporate Strategy & Business Development	426.1-426.5-Other Income Deductions	15,659
	908-910-Customer Service and Informational Expenses	3,241
	911-916-Sales Expense	1,543
	920-935-Administrative and General Expense	531,326
Corporate Strategy & Business Development Total		551,769
Customer Service	107-CWIP	115,863
	181-190-Deferred Debits	19,940
	417-421-Other Income	10,217
	426.1-426.5-Other Income Deductions	48
	901-905-Customer Accounts Expenses	2,781,322
	908-910-Customer Service and Informational Expenses	47,674
	911-916-Sales Expense	11,465
	920-935-Administrative and General Expense	909
Customer Service Total		2,987,438
Employee Communications	920-935-Administrative and General Expense	197,570
Employee Communications Total		197,570
Energy Delivery - Engineering/Design	107-CWIP	14,363,216
	130-176-Current and Accrued Assets	29,546
	408-409-Taxes	107
	426.1-426.5-Other Income Deductions	24,041

	500-514-Steam Power Generation	541,923
	546-557-Other Power Generation	80,635
	560-573-Transmission Expenses	5,594,148
	580-598-Distribution Expenses	1,199,216
	908-910-Customer Service and Informational Expenses	(62)
	920-935-Administrative and General Expense	193,935
Energy Delivery - Engineering/Design Total		22,026,705
Energy Delivery Construction, Operations & Maintenance (COM)	426.1-426.5-Other Income Deductions	1,457
	560-573-Transmission Expenses	42,944
	580-598-Distribution Expenses	732,441
	920-935-Administrative and General Expense	226,892
Energy Delivery Construction, Operations & Maintenance (COM) Total		1,003,734
Energy Markets - Fuel Procurement	426.1-426.5-Other Income Deductions	267
	500-514-Steam Power Generation	629,936
	920-935-Administrative and General Expense	72,335
Energy Markets - Fuel Procurement Total		702,538
Energy Markets Regulated Trading & Marketing	181-190-Deferred Debits	(751)
	408-409-Taxes	42
	417-421-Other Income	7,390
	426.1-426.5-Other Income Deductions	2,741
	546-557-Other Power Generation	2,198,080
	560-573-Transmission Expenses	134,004
	575.1-575.8-Regional Market Expenses	439,079
	920-935-Administrative and General Expense	565,316
Energy Markets Regulated Trading & Marketing Total		3,345,901
Energy Supply Business Resources	107-CWIP	466,887
	181-190-Deferred Debits	(29,928)
	426.1-426.5-Other Income Deductions	4,387
	500-514-Steam Power Generation	2,952,326
	546-557-Other Power Generation	1,568,190
	920-935-Administrative and General Expense	76,542
Energy Supply Business Resources Total		5,038,404
Energy Supply Engineering & Environmental	107-CWIP	4,743,117
	181-190-Deferred Debits	6,193
	426.1-426.5-Other Income Deductions	39,405
	500-514-Steam Power Generation	2,576,589
	546-557-Other Power Generation	792,188
	560-573-Transmission Expenses	16,263
	580-598-Distribution Expenses	17,310
	920-935-Administrative and General Expense	659,626
Energy Supply Engineering & Environmental Total		8,850,691

Executive Management Services	426.1-426.5-Other Income Deductions	70,299
	580-598-Distribution Expenses	73
	920-935-Administrative and General Expense	1,857,422
Executive Management Services Total		1,927,794
Facilities & Real Estate	107-CWIP	576,515
	130-176-Current and Accrued Assets	174
	181-190-Deferred Debits	1,268
	417-421-Other Income	3,148
	426.1-426.5-Other Income Deductions	8,518
	500-514-Steam Power Generation	3,837,733
	546-557-Other Power Generation	472,927
	560-573-Transmission Expenses	1,992,774
	575.1-575.8-Regional Market Expenses	49,167
	580-598-Distribution Expenses	2,595,292
	901-905-Customer Accounts Expenses	114,048
	908-910-Customer Service and Informational Expenses	45,839
	911-916-Sales Expense	4,289
	920-935-Administrative and General Expense	3,815,541
Facilities & Real Estate Total		13,517,233
Facilities Administrative Services	107-CWIP	17,234
Facilities Administrative Services Total		17,234
Finance & Treasury	107-CWIP	8,797,792
	130-176-Current and Accrued Assets	14,060
	181-190-Deferred Debits	357,557
	408-409-Taxes	3,589,962
	417-421-Other Income	13,120
	426.1-426.5-Other Income Deductions	25,305
	427-432-Interest Charges	152,595
	500-514-Steam Power Generation	799,242
	546-557-Other Power Generation	807,861
	560-573-Transmission Expenses	708,374
	575.1-575.8-Regional Market Expenses	53,282
	580-598-Distribution Expenses	236,052
	901-905-Customer Accounts Expenses	330,450
	908-910-Customer Service and Informational Expenses	6,862
	911-916-Sales Expense	3,431
	920-935-Administrative and General Expense	18,269,801
Finance & Treasury Total		34,165,746
Fleet	107-CWIP	78,586
Fleet Total		78,586
Government Affairs	426.1-426.5-Other Income Deductions	228,917
	920-935-Administrative and General Expense	180,623

Government Affairs Total		409,540
Human Resources	107-CWIP	93,832
	130-176-Current and Accrued Assets	51
	181-190-Deferred Debits	9,314
	227-230-Other Noncurrent Liabilities	223,630
	231-245-Current and Accrued Liabilities	2,875,099
	408-409-Taxes	6,779
	417-421-Other Income	5
	426.1-426.5-Other Income Deductions	9,460
	500-514-Steam Power Generation	2,357
	546-557-Other Power Generation	1,373
	560-573-Transmission Expenses	538
	580-598-Distribution Expenses	178,306
	901-905-Customer Accounts Expenses	381
	908-910-Customer Service and Informational Expenses	36,938
	911-916-Sales Expense	2
	920-935-Administrative and General Expense	3,346,966
Human Resources Total		6,785,031
Internal Audit	426.1-426.5-Other Income Deductions	80
	920-935-Administrative and General Expense	363,640
Internal Audit Total		363,720
Investor Relations	426.1-426.5-Other Income Deductions	137
	920-935-Administrative and General Expense	234,237
Investor Relations Total		234,374
Legal	107-CWIP	386,833
	426.1-426.5-Other Income Deductions	6,656
	560-573-Transmission Expenses	84,224
	920-935-Administrative and General Expense	1,752,303
Legal Total		2,230,016
Marketing & Sales	181-190-Deferred Debits	798,532
	417-421-Other Income	11,629
	426.1-426.5-Other Income Deductions	255
	908-910-Customer Service and Informational Expenses	(35,728)
	911-916-Sales Expense	84,868
	920-935-Administrative and General Expense	1,707,989
Marketing & Sales Total		2,567,545
Payment & Reporting	426.1-426.5-Other Income Deductions	56
	920-935-Administrative and General Expense	205,153
Payment & Reporting Total		205,209
Payroll	920-935-Administrative and General Expense	221,209
Payroll Total		221,209
Rates & Regulation	181-190-Deferred Debits	24,308
	426.1-426.5-Other Income Deductions	5,815
	920-935-Administrative and General Expense	1,346,371
Rates & Regulation Total		1,376,494
Receipts Processing	426.1-426.5-Other Income Deductions	1,062
	901-905-Customer Accounts Expenses	75,987
	920-935-Administrative and General Expense	280,603
Receipts Processing Total		357,652
Supply Chain	107-CWIP	3,478,995
	130-176-Current and Accrued Assets	5,126
	181-190-Deferred Debits	18,585
	408-409-Taxes	327
	417-421-Other Income	214
	426.1-426.5-Other Income Deductions	9,117
	500-514-Steam Power Generation	(310,045)
	546-557-Other Power Generation	124,115
	560-573-Transmission Expenses	(107,474)
	575.1-575.8-Regional Market Expenses	(8,188)
	580-598-Distribution Expenses	(221,934)
	901-905-Customer Accounts Expenses	151,498
	908-910-Customer Service and Informational Expenses	(33,120)
	911-916-Sales Expense	(3,139)
	920-935-Administrative and General Expense	1,108,725
Supply Chain Total		4,212,802
Grand Total		209,381,900

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

107	$	(1,142)
108		(55)
184		(2,525)
E501		(186,383)
E505		(30)
E512		(304)
E539		(492)
E542		(264)
E549		(101)
E552		(190)
E570		(37,430)
E584		(215)
E585		(143)
E586		(1,661)
E588		(83,187)
E593		(1,841)
E594		(1)
G874		(411)
G878		(140)
G879		(1,717)
G887		(6)
G892		(926)
		(319,164)

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INDEPENDENT ACCOUNTANT'S REVIEW REPORT

To the Board of Directors of
Southwestern Public Service Company
Amarillo, Texas

We have reviewed the historical dollar amounts included in schedules A-5, B-1, B-2, B-3, B-4, B-5, B-6, C-1, E-2, E-3, E-4, F-1, G-1, G-3, G-4, G-5, G-6, G-8, G-9, H-1, H-2, H-4, H-5, H-7, H-8, H-9, H-10, H-11, H-12, H-13, H-14, H-15, I-1, I-2, I-3, P-2, P-3, and P-4 (the "Schedules"), in the Electric Utility Rate Filing Package ("Rate Filing Package") of Southwestern Public Service Company ("SPS"), a New Mexico Corporation and wholly owned subsidiary of Xcel Energy Inc. (the "Company"), as of and for the 12 months ended June 30, 2022, submitted pursuant to Rule 17.9.530 and Rule 17.1.3 (the "Rate Filing Package Rules") of the New Mexico Public Regulation Commission ("NMPRC"). The Company's management is responsible for presenting the Schedules in the Rate Filing Package in accordance with the Rate Filing Package Rules prescribed by the NMPRC. Our responsibility is to express a conclusion on the Rate Filing Package based on our review.

Our review was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the review to obtain limited assurance about whether any material modifications should be made to the Rate Filing Package in order for them to be in accordance with the Rate Filing Package Rules prescribed by the NMPRC. The Schedules were prepared solely for inclusion in the Rate Filing Package and are not intended to be a presentation in conformity with accounting principles generally accepted in the United States of America. A review is substantially less in scope than an examination, the objective of which is to obtain reasonable assurance about whether the Rate Filing Package is in accordance with the Rate Filing Package Rules prescribed by the NMPRC, in all material respects, in order to express an opinion. Accordingly, we do not express such an opinion. We believe that our review provides a reasonable basis for our conclusion.

The pro forma adjustments, as adjusted amounts, estimates, non-accounting, and non-financial information included in the Schedules in the Rate Filing Package were not reviewed by us and, accordingly, we do not express an opinion or any other form of assurance on such information.

Based on our review, we are not aware of any material modifications that should be made to the Schedules in Rate Filing Package of the Company as of and for the 12 months ended June 30, 2022, in order for them to be in accordance with the Rate Filing Package Rules prescribed by the NMPRC.

This report is intended solely for the information and use of the management and Board of Directors of SPS and the NMPRC, pursuant to the Rate Filing Package Rules, and is not intended to be, and should not be, used by anyone other than the specified parties.

Deloitte & Touche LLP

November 16, 2022