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"), Title 18, Chapter 1, Subchapter K, Part 290.403, Subpart B, 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 $11.5 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 3.6 million electricity customers and 2 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 123,000 New Mexico electric customers (394,000 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 7.6 customers per square mile. The total electric customer count is comprised of: 73.7% New Mexico Residential customers (74.9% total company Residential customers), 17.4% New Mexico Commercial and Industrial customers (17.7% total company Commercial and Industrial customers), 7.5% New Mexico Lighting customers (5.8% total company Lighting customers), and 1.4% New Mexico Municipal and School customers (1.6% total company Municipal and School customers). SPS also serves six 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.

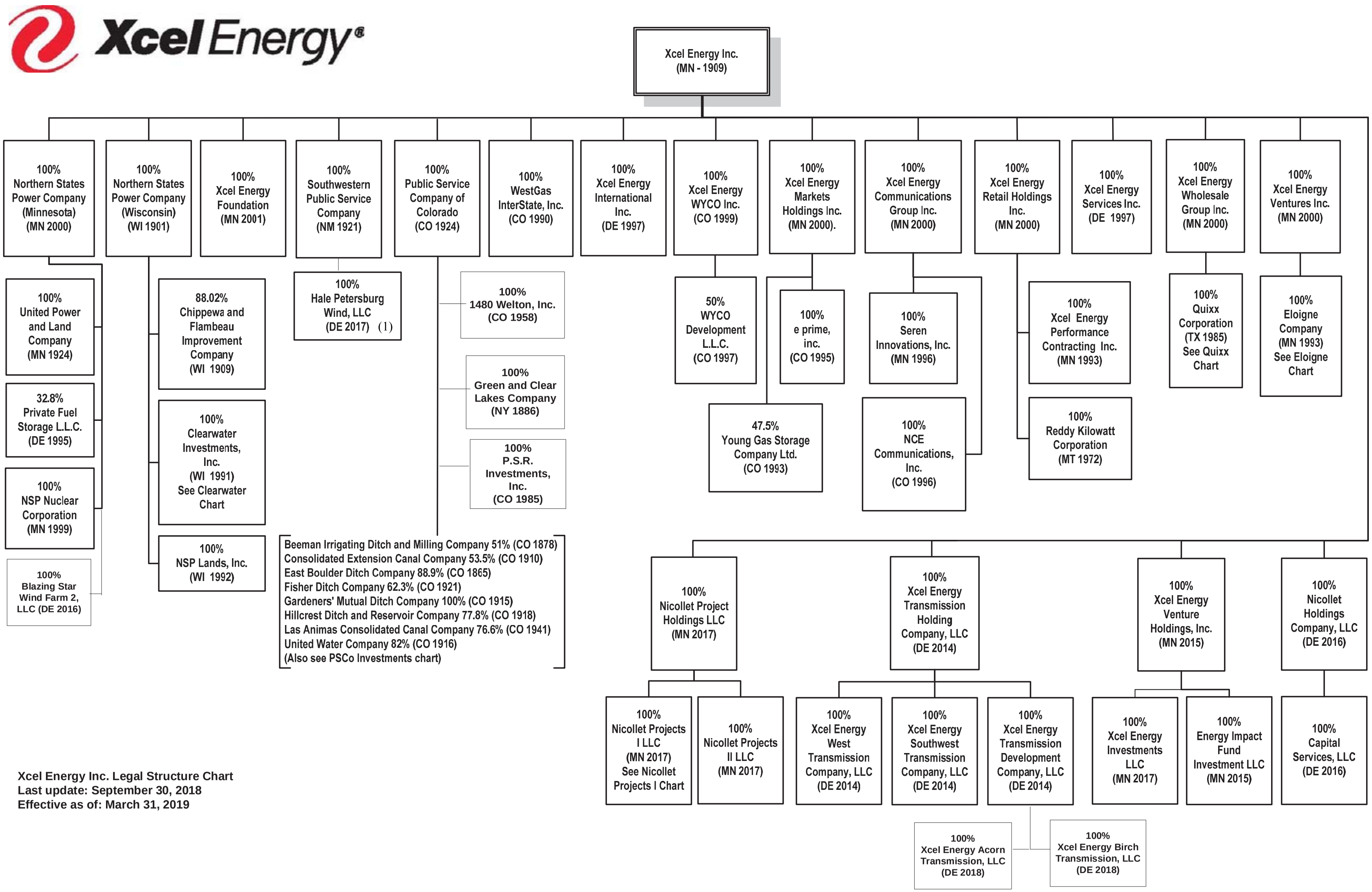
SPS is regulated by the 80 municipalities it serves in Texas, the Public Utility Commission of Texas, the New Mexico Public Regulation Commission and the FERC.

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 nine synchronous transmission ties with the SPP. Four 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); Groom, 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). One of these interconnections ties to Sunflower Electric Power Corporation near Holcomb, Kansas (345kV), and another one of these interconnections ties to Mid Kansas Electric Company near Guymon, Oklahoma (115kV).

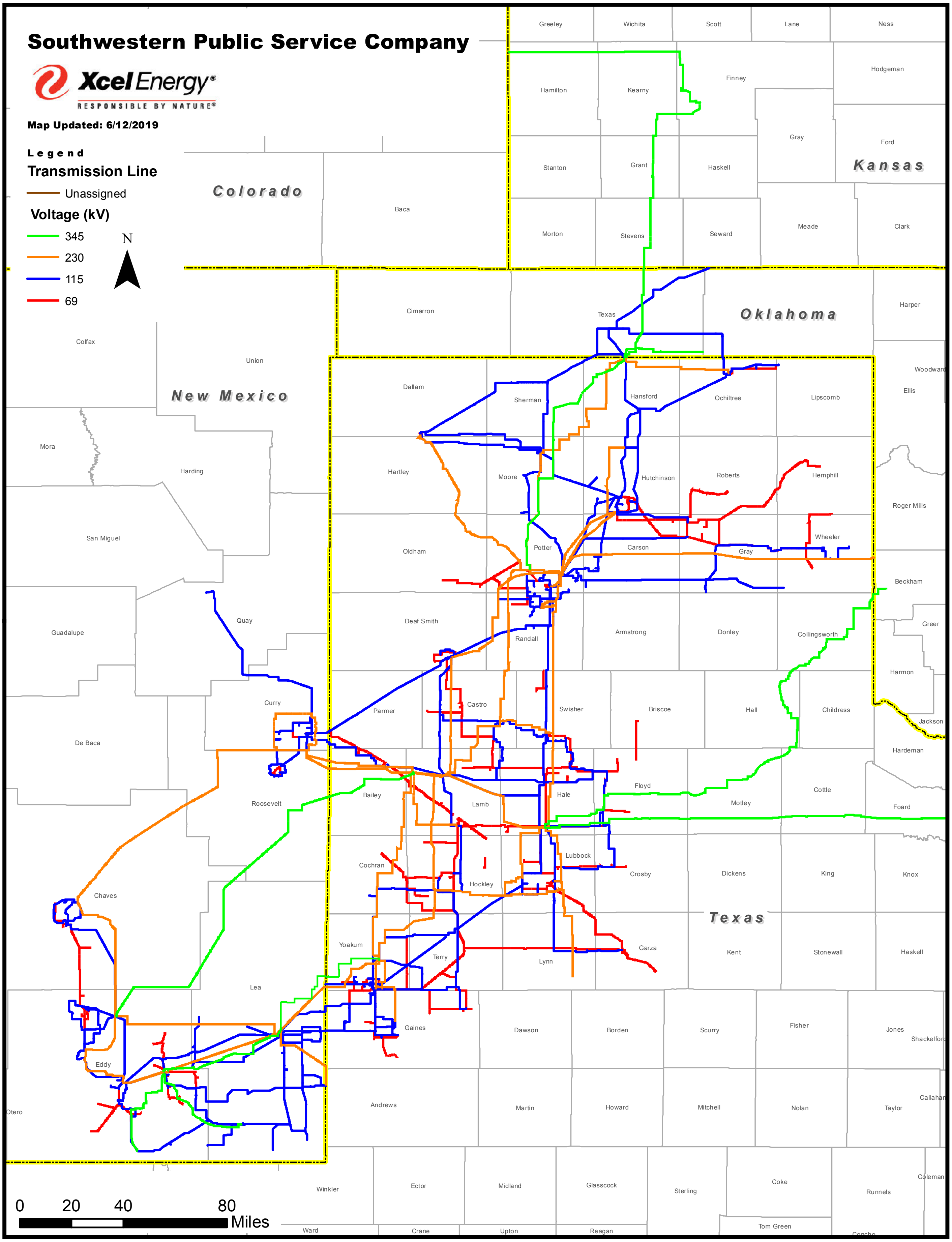
SPS is interconnected to the Western Interconnection through three high-voltage direct-current ("HVDC") converters owned by three utilities in the WECC. SPS is interconnected to the west jointly with El Paso Electric Company and Public Service Company of New Mexico ("PNM") at the Eddy County HVDC tie 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: September 30, 2018
Effective as of: March 31, 2019

Note:
(1) Non-operating entity associated with Commission-approved Hale Wind Project transaction, intended to be dissolved or otherwise eliminated.


Southwestern Public Service Company
Xcel Energy
RESPONSIBLE BY NATURE
Map Updated: 6/12/2019
Legend
Transmission Line
Unassigned
Voltage (kV)
345
230
115
69
N
Colorado
Kansas
Oklahoma
New Mexico
Texas
0 20 40 80
Miles

Southwestern Public Service Company

Description of Company: Public Utility (electric)

List and Description of Affiliates
As of March 31, 2019

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 (NSP-MN)**	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	Blazin Star Wind Farm 2, LLC	Owns interest in wind farms in Minnesota.	DE - 2016	NSP - MN	100.00%
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	75.86%
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	**Public Service Co. of Colorado (PSCo)**	Public utility (gas, electric & thermal).	CO - 1924	Xcel Energy Inc.	100.00%
13	PSR Investments Inc.	Owns certain life insurance policies acquired prior to 1986.	CO - 1985	PSCo	100.00%
14	1480 Welton Inc.	Holds real estate.	CO - 1958	PSCo	100.00%
15	Green and Clear Lakes Co.	Water storage for Cabin Creek hydro facility.	NY - 1886	PSCo	100.00%
16	Beeman Irrigating Ditch and Milling Co.	Cooling water for generating facilities.	CO - 1878	PSCo	51.00%
17	Consolidated Extension Canal Co.	Cooling water for generating facilities.	CO - 1910	PSCo	53.50%
18	East Boulder Ditch Co.	Cooling water for generating facilities.	CO - 1865	PSCo	88.90%
19	Fisher Ditch Co.	Cooling water for generating facilities.	CO - 1921	PSCo	62.30%
20	Gardeners' Mutual Ditch Co.	Cooling water for generating facilities.	CO - 1915	PSCo	100.00%
21	Hillcrest Ditch and Reservoir Co.	Cooling water for generating facilities.	CO - 1918	PSCo	77.80%
22	Las Animas Consolidated Canal Co.	Cooling water for generating facilities.	CO - 1941	PSCo	76.60%
23	United Water Co.	Cooling water for generating facilities.	CO - 1916	PSCo	82.00%
24	**WestGas InterState Inc.**	Natural gas transmission company.	CO - 1990	Xcel Energy Inc.	100.00%
25	**Xcel Energy Communications Group Inc. (Xcel Energy Comm.)**	Intermediate holding company for subsidiaries providing broadband telecommunications.	MN - 2000	Xcel Energy Inc.	100.00%
26	Seren Innovations Inc.**	Provides cable, telephone and high speed internet access.	MN - 1996 11-3-05 Calif. assets sold	Xcel Energy Comm	100.00%
27	**Xcel Energy Foundation**	Charitable activities.	MN - 2001	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 Markets Holdings Inc. (Xcel Energy Mkts)**	Intermediate holding company for subsidiaries. providing energy marketing services	MN - 2000	Xcel Energy Inc.	100.00%
30	e prime Inc. (e prime)**	Unregulated commodity marketing affiliate.	CO - 1995	Xcel Energy Mkts	100.00%
31	Young Gas Storage Co. Ltd.	Owns and operates an underground gas storage.	CO - 1993	Xcel Energy Mkts	47.50%
32	**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%
33	Reddy Kilowatt Corporation	Energy sales and marketing services.	MT - 1972	Xcel Energy Retail	100.00%
34	Xcel Energy Performance Contracting Inc.	Holds contracts related to energy conservation.	MN - 1993	Xcel Energy Retail	100.00%
35	**Xcel Energy Services Inc. (Xcel Energy Svcs.)**	Service company for Xcel Energy system.	DE - 1997	Xcel Energy Inc.	100.00%
36	**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%
37	Eloigne Co. (Eloigne)	Owns interests in affordable housing projects which qualify for low income housing tax credits.	MN - 1993	Xcel Energy Ventures	100.00%
38	Bemidji Townhouse LP	Owns interests in affordable housing projects.	MN - 5/3/93	Eloigne	99.00%

Southwestern Public Service Company

Description of Company: Public Utility (electric)

List and Description of Affiliates
As of March 31, 2019

Line No.	Name	Description	Incorporated	Owner	Ownership %
39	Chaska Brickstone LP	Owns interests in affordable housing projects.	MN - 10/7/97	Eloigne	99.99%
40	Cottage Court LP	Owns interests in affordable housing projects.	MN - 6/23/94	Eloigne	99.00%
41	Crown Ridge Apartments LP	Owns interests in affordable housing projects.	MN - 2/16/96	Eloigne	99.99%
42	Dakotah Pioneer LP	Owns interests in affordable housing projects.	ND - 4/20/99	Eloigne	99.99%
43	Edenvale Family Housing LP	Owns interests in affordable housing projects.	MN - 8/29/97	Eloigne	99.99%
44	Fairview Ridge LP	Owns interests in affordable housing projects.	MN - 12/20/93	Eloigne	99.00%
45	Farmington Family Housing LP	Owns interests in affordable housing projects.	MN - 2/16/99	Eloigne	99.99%
46	Farmington Townhome LP	Owns interests in affordable housing projects.	MN - 2/15/98	Eloigne	99.99%
47	Hearthstone Village LP	Owns interests in affordable housing projects.	ND - 9/14/97	Eloigne	99.00%
48	J&D 14-93 LP	Owns interests in affordable housing projects.	MN - 1/3/94	Eloigne	99.00%
49	Lauring Green LP	Owns interests in affordable housing projects.	MN - 8/14/89	Eloigne	99.00%
50	Links Lane LP	Owns interests in affordable housing projects.	MN - 8/11/93	Eloigne	99.00%
51	Lyndale Avenue Townhomes LP	Owns interests in affordable housing projects.	MN - 5/6/99	Eloigne	99.99%
52	Mahtomedi Woodland LP	Owns interests in affordable housing projects.	MN - 12/3/96	Eloigne	99.00%
53	Mankato Townhomes LLP	Owns interests in affordable housing projects.	MN - 6/20/97	Eloigne	59.99%
54	Marvin Garden LP	Owns interests in affordable housing projects.	MN - 4/1/94	Eloigne	99.00%
55	Moorhead Townhomes LP	Owns interests in affordable housing projects.	MN - 9/8/99	Eloigne	99.99%
56	Park Rapids Townhomes LP	Owns interests in affordable housing projects.	MN - 6/17/95	Eloigne	99.99%
57	Rochester Townhome LP	Owns interests in affordable housing projects.	MN - 2/5/98	Eloigne	99.00%
58	Rushford Housing LP	Owns interests in affordable housing projects.	MN - 3/27/96	Eloigne	99.99%
59	Safe Haven Homes LLC	Owns interests in affordable housing projects.	DE - 1997	Eloigne	100.00%
60	Shade Tree Apartments LP	Owns interests in affordable housing projects.	MN - 6/11/99	Eloigne	99.99%
61	Shakopee Boulder Ridge LP	Owns interests in affordable housing projects.	MN - 10/20/98	Eloigne	99.99%
62	Shenandoah Woods LP	Owns interests in affordable housing projects.	MN - 8/29/97	Eloigne	99.99%
63	Sioux Falls Partners LP	Owns interests in affordable housing projects.	SD - 9/2/94	Eloigne	99.00%
64	St. Cloud Housing LP	Owns interests in affordable housing projects.	MN - 1/13/03	Eloigne	99.99%
65	Tower Terrace LP	Owns interests in affordable housing projects.	MN - 5/9/94	Eloigne	99.00%
66	**Xcel Energy Wholesale Group Inc. (Xcel Energy Wholesale)****	Intermediate holding company. for subsidiaries providing wholesale energy	MN - 2000	Xcel Energy Inc.	100.00%
67	Quixx Corporation (Quixx Corp.)**	Energy related projects.	TX - 1985	Xcel Energy Wholesale	100.00%
68	Quixx Carolina Inc. (Quixx Carolina)**	Energy related projects.	TX - 1995	Quixx Corp.	100.00%
69	Quixxlin Corp. (Quixxlin)**	Energy related projects.	DE - 1997	Quixx Corp.	100.00%
70	**Xcel Energy WYCO Inc. (Xcel Energy WYCO)**	Finances and holds 50% interest in WYCO Development LLC.	CO - 1999	Xcel Energy Inc.	100.00%
71	WYCO Development LLC	Acquire, own and lease natural gas transportation facilities.	CO - 1997	Xcel Energy WYCO	50.00%
72	**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%
73	Xcel Energy Southwest Transmission Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
74	Xcel Energy Transmission Development Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
75	Xcel Energy Acorn Transmission, LLC	Provide transmission services.	DE - 2018	Xcel Energy Transmission Development Company, LLC	100.00%
76	Xcel Energy Birch Transmission, LLC	Provide transmission services.	DE - 2018	Xcel Energy Transmission Development Company, LLC	100.00%

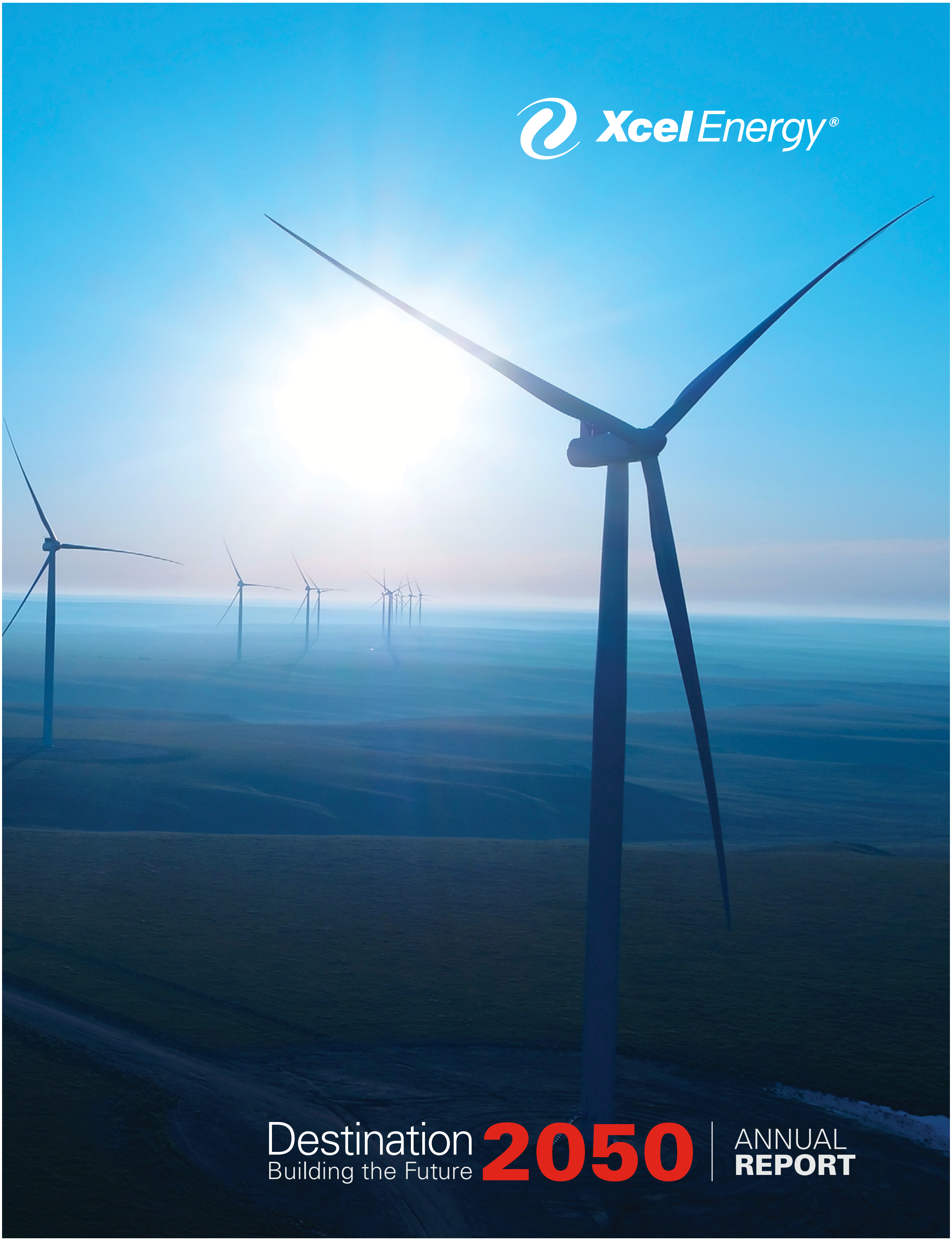
Southwestern Public Service Company

Description of Company: Public Utility (electric)

List and Description of Affiliates
As of March 31, 2019

Line No.	Name	Description	Incorporated	Owner	Ownership %
77	Xcel Energy West Transmission Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
78	**Xcel Energy Venture Holdings, Inc.**	Holdling Company.	MN - 2015	Xcel Energy Inc.	100.00%
79	Energy Impact Fund Investment LLC	Energy Investment.	MN - 2015	Xcel Energy Venture Holdings, Inc.	100.00%
80	Xcel Energy Investments LLC	Energy Investment.	MN - 2017	Xcel Energy Venture Holdings, Inc.	100.00%
81	**Nicollet Holdings Company, LLC**	Holding Company.	DE - 2016	Xcel Energy Inc.	100.00%
82	Capital Services, LLC	Internal Support Service.	DE - 2016	Nicollet Holdings Company, Inc.	100.00%
83	Nicollet Project Holdings LLC	Holding Company.	MN - 2017	Xcel Energy Inc.	100.00%
84	Southwestern Public Service Company	Public Utility.	NM - 1921	Xcel Energy Inc.	100.00%
85	Hale Petersburg Wind, LLC	Non-operating entity associated with Commission-approved Hale Wind Project transaction, intended to be dissolved or otherwise eliminated	DE - 2017	Southwestern Public Service Company	100
86	Nicollet Projects I LLC	Energy generation investment.	MN - 2017	Nicollet Project Holdings LLC	100.00%
87	Betcher CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
88	Foreman's Hill CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
89	Grimm CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
90	Heyer CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
91	Huneke CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
92	Johnson I CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
93	Johnson II CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
94	Krause CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
95	RJC I CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
96	RJC II CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
97	Scandia CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
98	School Sisters CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
99	Webster CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Holdings Company, LLC	100.00%
100	Nicollet Projects II LLC	Energy generation investment.	MN - 2017	Nicollet Project Holdings LLC	100.00%

Notes: ** Company is being classified as in discontinued operations.


Xcel Energy®
Destination
Building the Future
2050
ANNUAL
REPORT

Destination **2050**

Our bold carbon-free **FUTURE**

Xcel Energy has long been a leader in delivering clean energy while maintaining outstanding reliability and affordability. Back in 2005, we were the leading utility wind energy provider in the country, despite the fact that wind comprised only 3 percent of our generation. By 2027, we expect renewable energy — the vast majority being wind — will account for 48 percent of our mix and will be our largest source of energy for our customers.

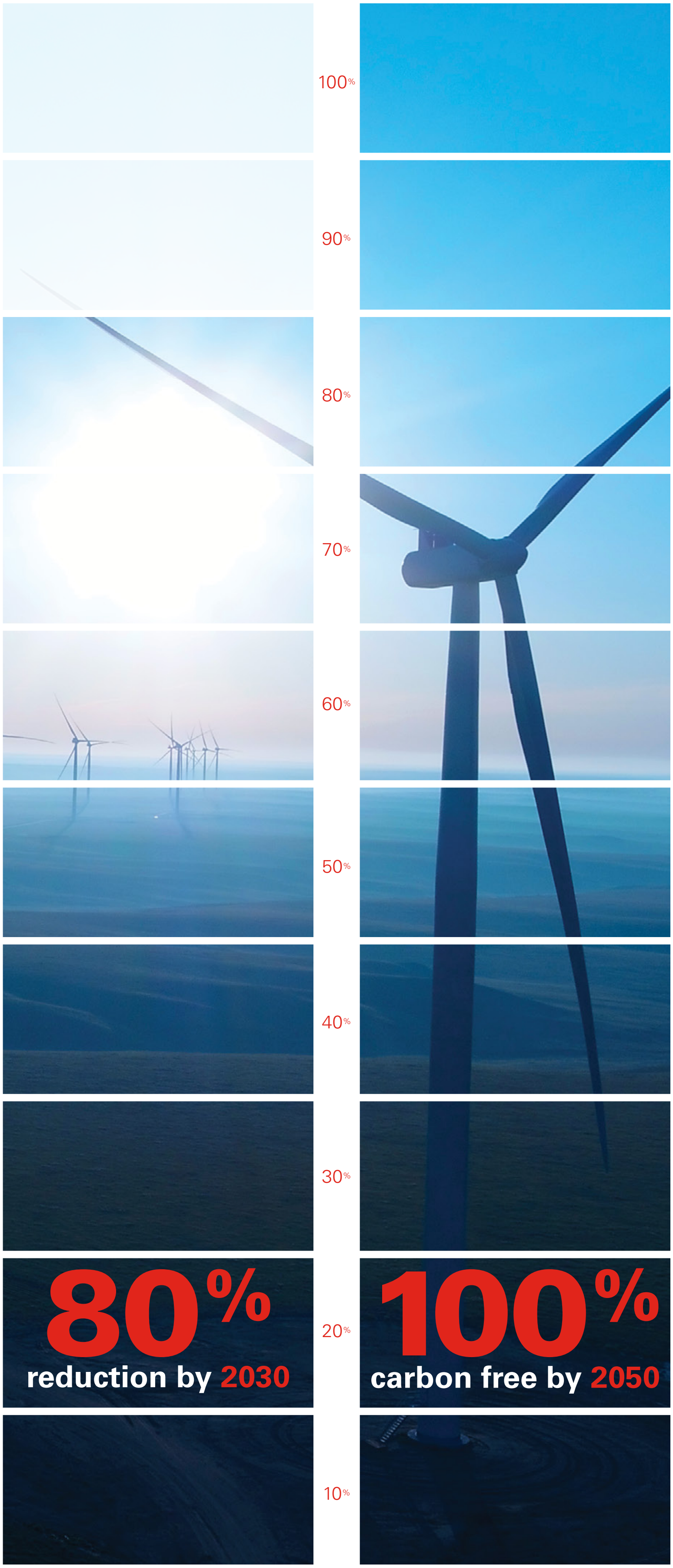
Along the way, we've made steady progress reducing carbon dioxide by transitioning away from fossil fuels, incorporating renewables and developing award-winning energy efficiency programs. Our 2018 carbon emissions are approximately 40 percent lower than our 2005 baseline. That progress put us on pace to hit our previous goal of reducing carbon 60 percent across all eight states in which we do business by 2030.

But a confluence of market forces — improving technology, falling prices and the risk of climate change — convinced us that we can do more, sooner. That's why in December, we became the first electric utility in the country to announce our aspiration to produce 100-percent carbon-free electricity for customers by 2050. At the same time, we announced a new interim target of reducing carbon dioxide emissions 80 percent by 2030.

Significant advances in technology and our ability to integrate high levels of renewable energy onto our system give us the confidence that we expect to hit our 80 percent target by 2030 using existing technologies. To produce 100-percent carbon-free electricity for customers by 2050 will require a dispatchable carbon-free energy source that is not available today. Of course, reliability and affordability must be part of the equation to successfully arrive at our destination.

Setting our sights on this ambitious vision — Destination 2050 — allows us to drive the conversation rather than react to it. It also gives us time for the development of technologies not currently available that will be critical for achieving 100-percent carbon-free electricity. And as important, it gives us a long runway to work with our local communities and employees to help prepare for a clean energy economy.

We're excited to make advances toward Destination 2050 and can't wait to build the future together.



Some sections in this annual report, including the letter to shareholders, contain forward-looking statements. For a discussion of factors that could affect operating results, please see management's discussion and analysis listed in the table of contents of the Form 10-K.

Ben Fowke, Chairman, President and CEO

Dear Fellow Shareholders:

2018 was a year of significant accomplishments for our company. While we achieved outstanding financial performance, marked major milestones in our Steel for Fuel strategy, and partnered with other utilities to restore power in Puerto Rico following Hurricane Maria, it was our announcement that we see a path to achieve 100-percent carbon-free energy by 2050 that took the spotlight.

Xcel Energy has long been a leader in clean, renewable energy, but we took that to a new level when we became the first major U.S. electric company to announce a carbon-free vision — to serve customers with zero-carbon electricity by 2050. "Destination 2050: Building the Future" captures our long-range vision. But our vision to deliver 100-percent carbon-free energy by 2050 is more than just words. I like to think that we are not just talking about the future, we're building it today.

Outstanding Financial Performance

For the 14th consecutive year, we met or exceeded our earnings guidance. We delivered 2018 GAAP and ongoing earnings of $2.47 per share, at the top end of our original earnings guidance range, compared to GAAP earnings of $2.25 per share and ongoing earnings of $2.30 per share in 2017.

Xcel Energy also increased your dividend 5.6 percent in 2018, extending our streak of dividend growth to 15 consecutive years. We maintained our dividend objective of 5 to 7 percent annual growth, which reflects our confidence in our long-term financial plan.

Strong earnings were driven in part by positive sales growth, particularly to support oil and gas production in Texas and New Mexico. Electric sales increased 1.3 percent and natural gas sales increased 2.4 percent, indicating strong customer growth despite continued advances in energy efficiency.

Because our financial results were so strong during the first two quarters, we made the strategic decision to reinvest earnings into our business for system maintenance and vegetation management. This was a factor in our 3.6 percent increase in operating and maintenance (O&M) expenses in 2018. We remain committed to our long-term objective of improving operating efficiencies and eliminating costs to deliver greater value to our customers and shareholders.

As a result of our continued strong performance, our total shareholder return has outpaced our peer group. Our three-year total shareholder return was 51.1 percent compared to 34.6 percent for our peer group, and our five-year return was 109.5 percent compared to 65.9 percent for our peer group. In addition, our stock price (ticker: XEL) closed at an all-time high of $53.68 in December, and has subsequently set several new all-time highs in early 2019.

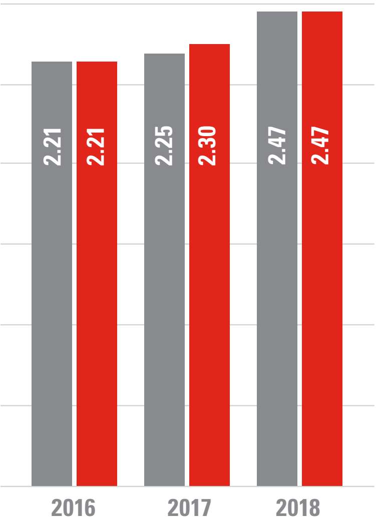
Building the Future Today

We continue to make strong progress in executing our Steel for Fuel growth strategy and are well-positioned to lead the clean energy transition and deliver strong shareholder value for years to come. Developing and owning wind farms brings our customers low-cost, carbon-free wind energy, while it creates economic development for communities and new investments for shareholders. It is a win-with-wind strategy that appeals to multiple stakeholders.

Our Steel for Fuel wind strategy is visible on the eastern plains of Colorado, where the largest wind farm we've ever built —

XCEL ENERGY EARNINGS PER SHARE

Dollars per share (diluted)



GAAP (generally accepted accounting principles) earnings per share

Ongoing earnings per share*

*A reconciliation to GAAP earnings per share is located in Item 7 of the Form 10-K.

FINANCIAL HIGHLIGHTS

	2017	2018
Total GAAP earnings per share	2.25	2.47
Ongoing earnings per share	2.30	2.47
Dividends annualized	1.44	1.52
Stock price (close)	48.11	49.27
Assets (millions)	43,030	45,987

Company description

Xcel Energy is a major U.S. electric and natural gas company with annual revenues of $11.5 billion. Based in Minneapolis, Minnesota, the company operates in eight states and provides a comprehensive portfolio of energy-related products and services to 3.6 million electricity customers and 2 million natural gas customers.

the 600-megawatt Rush Creek Wind Farm — began producing enough carbon-free energy to power 325,000 homes.

We are in the midst of one of the largest multi-state wind expansions in the country. With the completion of Rush Creek in Colorado, we have 11 remaining wind farms under development. In 2018, we secured the last of the necessary approvals for the projects, eight of which we will own. Five wind farms will be completed this year, with five expected to come online in 2020. The Dakota Range Wind Farm in South Dakota is set to begin service in 2021 after the production tax credit begins to phase down.

But, we aren't stopping there. We need to make progress every day to meet our vision of providing carbon-free electricity for customers by 2050 and reducing carbon emissions 80 percent system wide by 2030 (compared to 2005 levels). At the end of 2018, we had reduced carbon emissions by approximately 40 percent.

Our carbon footprint will continue to shrink following the approval of our Colorado Energy Plan, which includes the early retirement of two coal units at the Comanche Generating Station in Pueblo, and replacing that generation with a combination of wind, solar, battery storage and natural gas. By 2026, when all these projects are complete, more than half of the energy we produce in Colorado will come from renewable sources.

Another innovative way to provide Steel for Fuel ownership opportunities for shareholders is to buy out existing power purchase agreements. Late last year we announced agreements to buy two older wind farms in southern Minnesota and re-power them with today's advanced wind technology. While those always require regulatory approval, we intend to continue to pursue similar opportunities in 2019 and beyond.

Enhancing the Customer Experience

Leading the clean energy transition positions us to better serve our customers as we develop new programs to help them achieve their sustainability goals. Last year our all-renewable program in Minnesota and Colorado completely sold out. Renewable*Connect gives customers the opportunity to purchase up to 100 percent of certified renewable energy to power their homes and businesses. We have filed plans for a second phase of this program in Minnesota, this time uncapped and scalable, so we can meet the growing demand for this entirely clean energy product. A similar program has been approved in Wisconsin and will provide a greener option for customers starting later in 2019.

A growing percentage of customers want to reduce their carbon footprint not only in their homes or businesses, but in the vehicles they drive as well. Electric vehicles are a growing consumer choice, and we are taking a three-pronged approach to help our customers seamlessly make the transition. We have several pilots underway in Minnesota to provide home charging options and public charging infrastructure, and to partner with communities and business customers to convert their fleets from traditional to electric vehicles. We recently announced a $25 million investment in electric vehicle infrastructure and believe these pilots will help our customers reduce energy and meet their sustainability needs. We expect to expand our electric vehicle efforts to other states in 2019 and beyond (read more on pages 10-11).

Building a smarter and stronger energy grid that better serves customers is at the heart of our Advanced Grid Intelligence and Security initiative. As technology continues to advance, we are ensuring the way we deliver electricity to homes and businesses keeps improving too. Through this effort we will upgrade our infrastructure, improve security and reliability and leverage advanced meters to provide customers more choices for managing their energy use. We will begin installation of new meters in Colorado late in 2019 and plan to file for approval for our advanced grid initiative in Minnesota this year.

Regulatory Advancements

Effective stakeholder engagement is an important part of generating favorable regulatory outcomes, and we had several regulatory accomplishments in 2018, starting with approvals of our wind projects in Texas and New Mexico.

Colorado regulators approved our long-term pricing agreement with EVRAZ, a large steel mill and the second-largest employer in Pueblo. This agreement was crucial for EVRAZ to continue its operation in Pueblo and allow for expansion into the future.

One of the largest regulatory issues across our service territory in 2018 was working with our policy makers and stakeholders to determine the best way to distribute tax reform benefits to our customers without negatively impacting our credit metrics. Solutions varied by jurisdiction, but in all, we are in the process of returning more than $300 million of tax benefits to our customers.

Regulators are reviewing our purchase agreement of the Mankato Energy Center, a natural gas facility currently under expansion that has served our customers through a PPA contract. We believe that natural gas will serve as an important bridge fuel that works well with high levels of renewable penetration.

While we prepare for our next Upper Midwest resource plan that will be filed in the summer of 2019, we will include a dialogue with the Minnesota commission about the importance of operating our nuclear plants through their license periods in the early 2030s. It's important that we operate our fleet efficiently and effectively, which is exactly what we did in 2018. The fleet delivered energy 96 percent of the time, while reducing its O&M costs by almost 3 percent (read more on pages 12-13).

Operational Excellence

At the heart of Xcel Energy's culture is the commitment to getting better every day. We've engaged our employees to find innovative ways to reduce costs and gain efficiencies, and they have delivered. By implementing continuous improvement suggestions from our employees, we saved $59 million of O&M expenses in 2018. We also developed the in-house expertise in lean management techniques to apply continuous improvement efforts to other areas of the business in 2019 and beyond.

Our always-improving mindset is also at work when it comes to safety, of our employees and the public. In 2018, we built a state-of-the-art natural gas training facility in Minnesota to better train employees and the first responders who we work with in our communities. I am pleased that we had our best public safety performance ever, as measured by gas emergency response, and achieved first quartile performance when it comes to employee safety. We've reduced employee injuries by more than 50 percent since we implemented our Journey to Zero employee safety program.

Living Our Values

We refreshed our corporate values in 2018 to bring a sharp focus and intention to how we want all of our 11,000 employees to approach their work each and every day. These new values — Connected, Committed, Safe and Trustworthy — were crafted and refined with employees engaged along the way.

Exceptional people, grounded in a values-driven organization, is a winning combination that's getting noticed. Xcel Energy has been fortunate to receive recognition from publications like *Forbes* and *Fortune*, which have repeatedly listed us as among the world's best companies. *Utility Dive* named Xcel Energy its 2018 Utility of the Year, and we were chosen among the 100 Best Corporate Citizens by *Corporate Responsibility Magazine*.

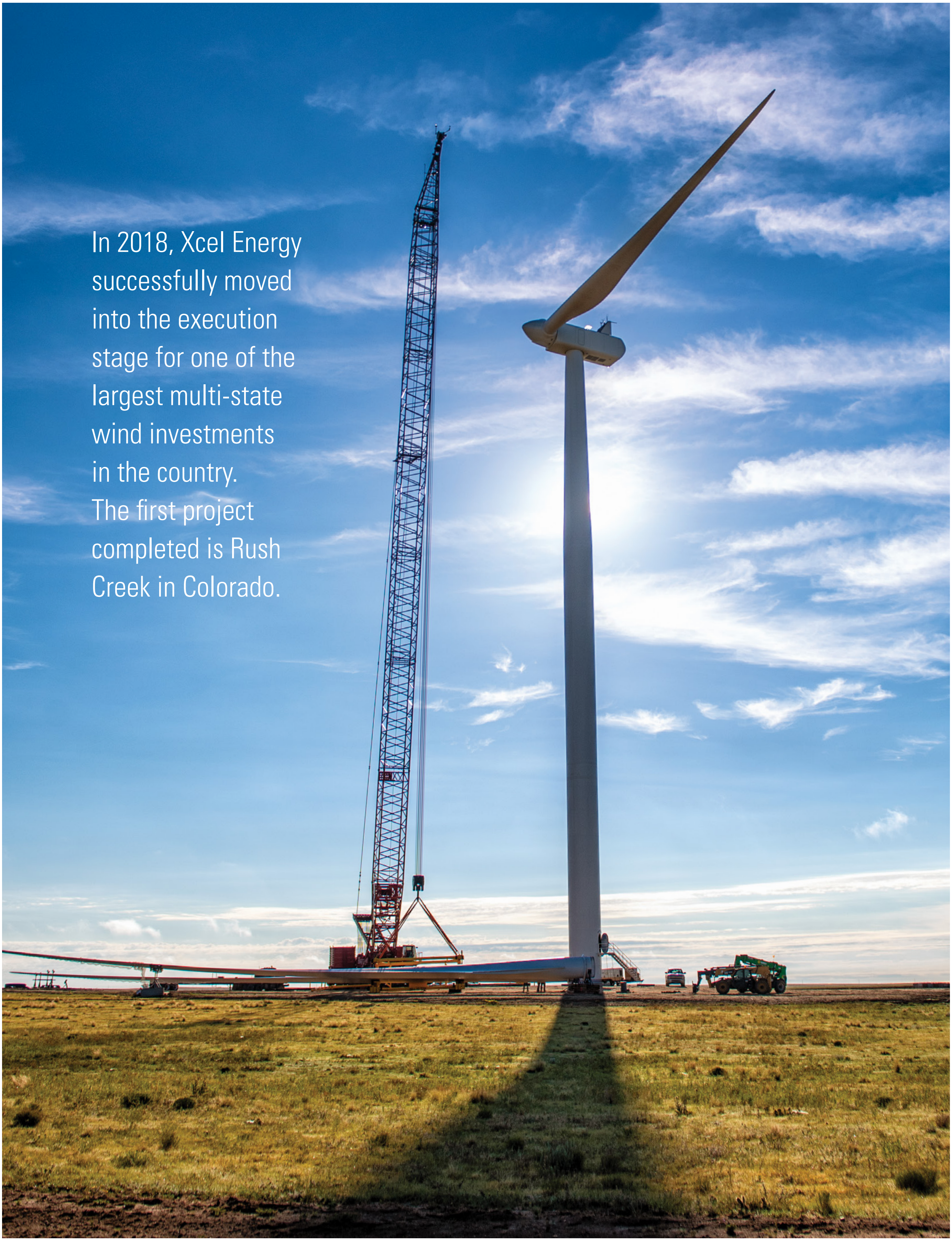
One of the things I am most proud of is our collective commitment to the communities where we serve. In the last year we gave back in a big way, donating more than $11 million and 90,000 volunteer hours to community organizations. Our efforts could be felt in everything from environmental improvements like tree plantings and other greening, to supporting economic self-sufficiency through mentoring and training efforts.

As we continue to build the future, we have Destination 2050 squarely in our sights. But as you can see, it is about more than just reducing our carbon footprint and delivering 100-percent carbon-free energy to our customers and communities by 2050. Destination 2050 is about always innovating to deliver best-in-class service to our customers, standing squarely with our communities to help them achieve their energy and economic development goals, engaging with our employees so they can bring their best to work every day and making an impact in our own backyards.

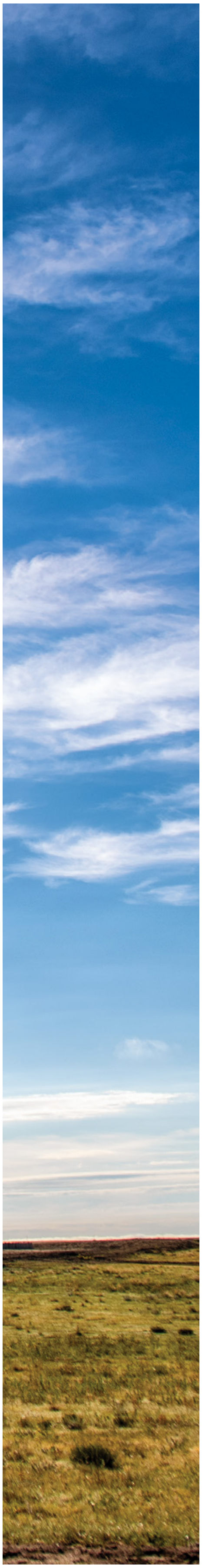
Thank you to our customers, shareholders, employees and stakeholders for helping make 2018 an outstanding year for Xcel Energy.

Sincerely,

Ben Fowke
Chairman, President and
Chief Executive Officer



In 2018, Xcel Energy successfully moved into the execution stage for one of the largest multi-state wind investments in the country. The first project completed is Rush Creek in Colorado.



Wind projects receive green light

Wind farms aren't built just anywhere land is for sale. They are complex projects that require extensive planning and permitting, significant outreach to neighboring property owners and other stakeholders, and, of course, regulatory approval.

It's one thing to propose new wind projects. It's another to shepherd them through the approvals necessary to get new wind farms constructed. Last year, we were able to secure the last of the necessary approvals for one of the largest multi-state wind investments in the country — 12 wind farms in seven states. The first wind project, Rush Creek in Colorado, was completed in 2018.

Appropriately, state and local interests drive the discussion. Some communities and regulators are focused on wind energy's ability to save customers money and to drive economic development. Others are attracted to the fact that more wind energy on our system allows us to continue reducing carbon emissions. What makes our Steel for Fuel strategy of building and owning wind farms widely appealing is its ability to deliver both economic and environmental benefits.

New wind farms and the accompanying substations and transmission lines needed to deliver the energy to market are powerful sources of economic development, often in rural areas. Our multi-state wind expansion is expected to create 2,700 construction jobs and 150 full-time positions, and generate $800 million in landowner lease and property tax payments over the lives of the projects.

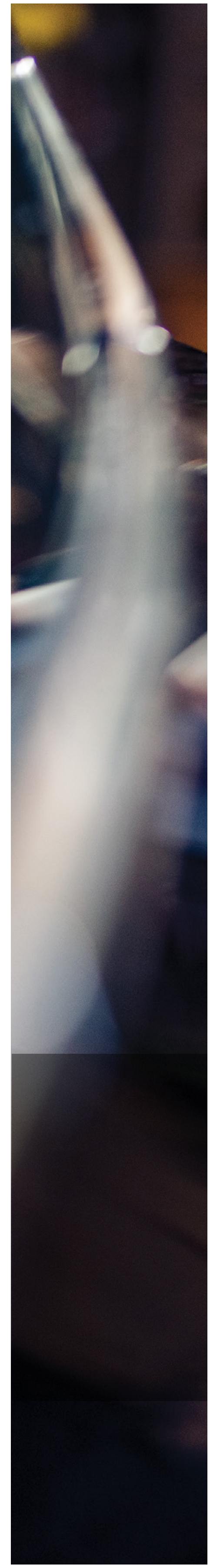
By 2027, we expect 39 percent of our energy will be supplied by wind — nearly double the amount on our system in 2017. That means wind energy would generate enough clean energy to power approximately six million homes and avoid more than 28 million tons of carbon emissions annually.

Colorado Energy Plan Gains Approval

We have secured regulatory approval for our Colorado Energy Plan, which will allow Xcel Energy to deliver on our vision to provide low-cost, clean renewable energy for our customers, stimulate economic development in rural Colorado and substantially reduce our carbon emissions.

This project required significant stakeholder outreach and engagement and received support from more than 20 business groups and environmental organizations. The Colorado Energy Plan paves the way for the early retirement of two coal units at the Comanche Generating Station in Pueblo. When fully executed in 2026, 55 percent of our Colorado energy mix is expected to come from renewable sources while saving customers money on their bills.

The first wind project in the Colorado plan — a 500-megawatt wind farm called Cheyenne Ridge — is expected to be completed in late 2020, assuming final regulatory approvals are secured.



All charged up about driving electric

EV initiative focused on the customer experience

Twin Cities software engineer Adam Carstensen purchased his first EV — a Tesla Model 3 — in November 2018. A few weeks before delivery, Adam contacted Xcel Energy to set up charging equipment in his garage.

The timing was perfect. The Minnesota Public Utilities Commission just approved an EV pilot program to provide advanced home charging equipment for 100 residential customers. The program was advantageous for Adam because the new equipment charges EVs faster than previous technology and includes energy monitoring technology that eliminates the need to install a new dedicated meter and service solely for EV charging.

"Once the pilot opened, I responded within a minute. I was one of the first customers in Minnesota to receive the new charging equipment. Not having to install a second meter saved me $1,700 dollars. It was a great experience — very seamless," Adam said.

Adam can drive up to 300 miles on a full charge. He drives his Tesla 25 miles to and from work each workday and uses it for trips throughout the Twin Cities without thinking twice. For longer trips, he plans ahead using an app on his phone that shows where public fast-charging stations are located.

Once he's done driving for the day, Adam plugs in his vehicle at home. At 9:00 each evening, the charging process automatically begins on Xcel Energy's EV electric pricing plan, which is more than 50 percent lower than standard residential pricing. Because the need for electricity demand falls at night, EV owners are encouraged to save money by charging overnight. Charging an EV on Xcel Energy's off-peak plan is the equivalent to approximately 50 cents per gallon.

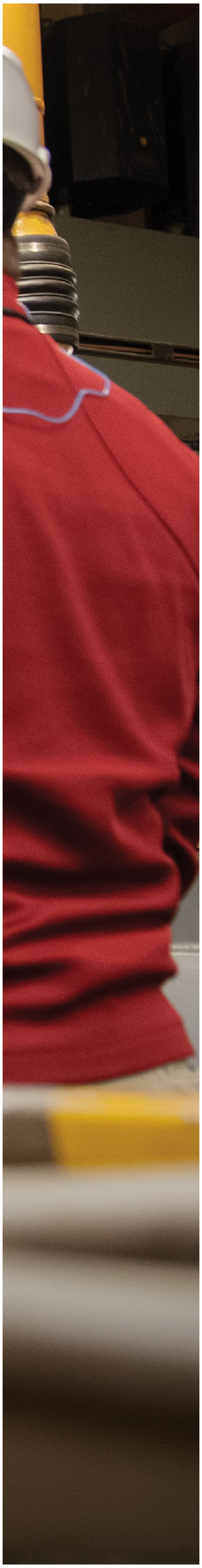
"I save about $40 dollars a month in fuel costs," said Adam, who also took advantage of a $7,500 federal tax credit. "The bigger savings comes from maintenance. The only regular maintenance I have is rotating the tires and filling up the windshield-washer fluid. There is no engine — no oil changes."

Although EV customers can realize cost savings compared to traditional vehicles, Adam first began researching hybrid and EVs because of the environmental benefits. Today, a conventional car emits 5.2 tons of carbon dioxide per year. By comparison, EVs charged on Xcel Energy's system in Minnesota produce only 1.5 tons of carbon per year. That number is expected to drop to 0.4 tons by 2030 as our electricity becomes greener and greener. Adam's car doesn't produce any carbon emissions when it's charged at home because he also participates in our Renewable*Connect program at the 100 percent level, meaning all the electricity in his house comes from certified wind or solar renewable energy sources.

"EVs are better for the environment. Climate change is a real problem and this is something that we could do to try and help," said Adam, who is concerned about the planet his two young children will inherit.

Adam Carstensen (left), a participant in the new Minnesota electric vehicle home charging pilot program, goes over his home charging equipment with Neal Callinan of Xcel Energy.

Ben Fowke, Chairman, President and CEO, visits with employees at our Prairie Island nuclear facility near Red Wing, Minnesota.



Nuclear checks all the boxes

We've long appreciated the value nuclear energy delivers on a number of fronts: the "round-the-clock" affordable energy it provides, the environmental benefits of carbon-free generation, and the $1 billion of annual economic impact to the Minnesota economy where our plants are located.

An increasing number of stakeholders have come to appreciate nuclear power for those same reasons. The carbon-free nature of nuclear energy, coupled with its 24x7 power, make it extremely valuable to the clean energy transition.

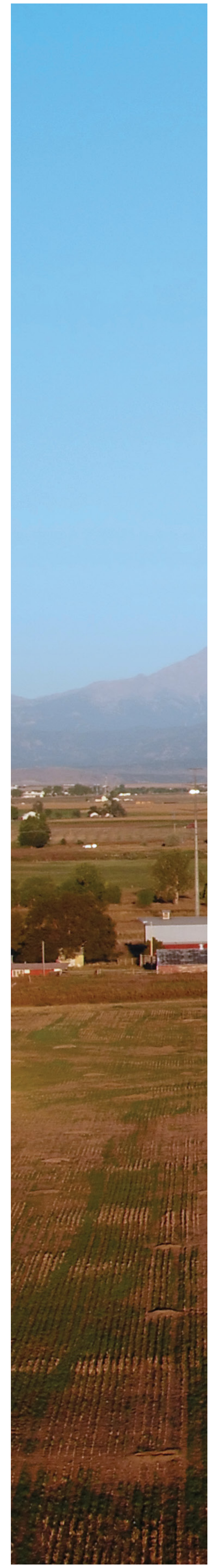
The clean energy transition cannot work if reliability and affordability are not part of the equation. Reliable, affordable and clean must work together, and nuclear energy checks all the boxes.

For us, a critical part of our clean energy vision is operating our nuclear units at least through their current licenses, which expire in the early 2030s. We operate three nuclear units in Minnesota — one at Monticello and two units at Prairie Island — that provide 13 percent of our energy mix. Because nuclear energy provides the only carbon-free, always on energy source for our system, it makes pragmatic sense that nuclear remains an important part of our energy future.

Employees working at our nuclear plants understand that running those facilities safely, effectively and efficiently is of the utmost importance. During the last few years, we've empowered our team to drive innovation to reduce costs — and they've delivered. In the last three years, our nuclear employees have eliminated about $40 million of operating and maintenance costs. In 2018, our nuclear employees set a generation record, producing more than 14.6 million megawatt hours of energy, all without a lost-time injury. In addition to working safely, last year the team worked effectively and efficiently, producing power 96 percent of the time while reducing its operating and maintenance costs by nearly 3 percent — a winning formula.

We've also found innovative ways to reduce fuel costs. By developing a new fuel design, the nuclear engineering team significantly reduced the amount of fuel consumed during operations. This approach extends the period of time between scheduled refueling from 18 months to 24 months, which will save approximately $4 to $5 million per year in fuel costs. Additionally, we expect to generate $70 million in savings over the next 15 years as the need for two refueling outages will be eliminated.

Clean, affordable, reliable. Nuclear energy produced in Minnesota continues to check all the boxes.



A sight to behold, from a distance

Forty miles north of Denver, a first-of-its-kind unmanned aircraft system flight took place last summer. Very few people saw it — and that's the point.

In 2018, Xcel Energy became the first public utility in the country to receive permission from the Federal Aviation Administration (FAA) to fly drones beyond the operator's line of sight to inspect transmission lines. The flights, which began in July and continued monthly through the year, are part of a program to prove the value of using unmanned aircraft to inspect critical infrastructure in the power generation industry.

The Altus ORC2, a 35-pound drone not available in the retail market, collected images and volumes of data that was then analyzed to identify potential issues that could impact the reliability of the electric transmission grid. More than 1,000 miles of test flights were tracked by a field operations team of four individuals located on the ground — a pilot, an observer and two other team members monitoring the data collection.

"FAA team members came to Colorado to observe our transmission inspection flights first hand," said Eileen Lockhart, who manages Xcel Energy's UAS program. "They were pleased with the results. If all continues to go well, the program will be expanded to our peer companies in the future."

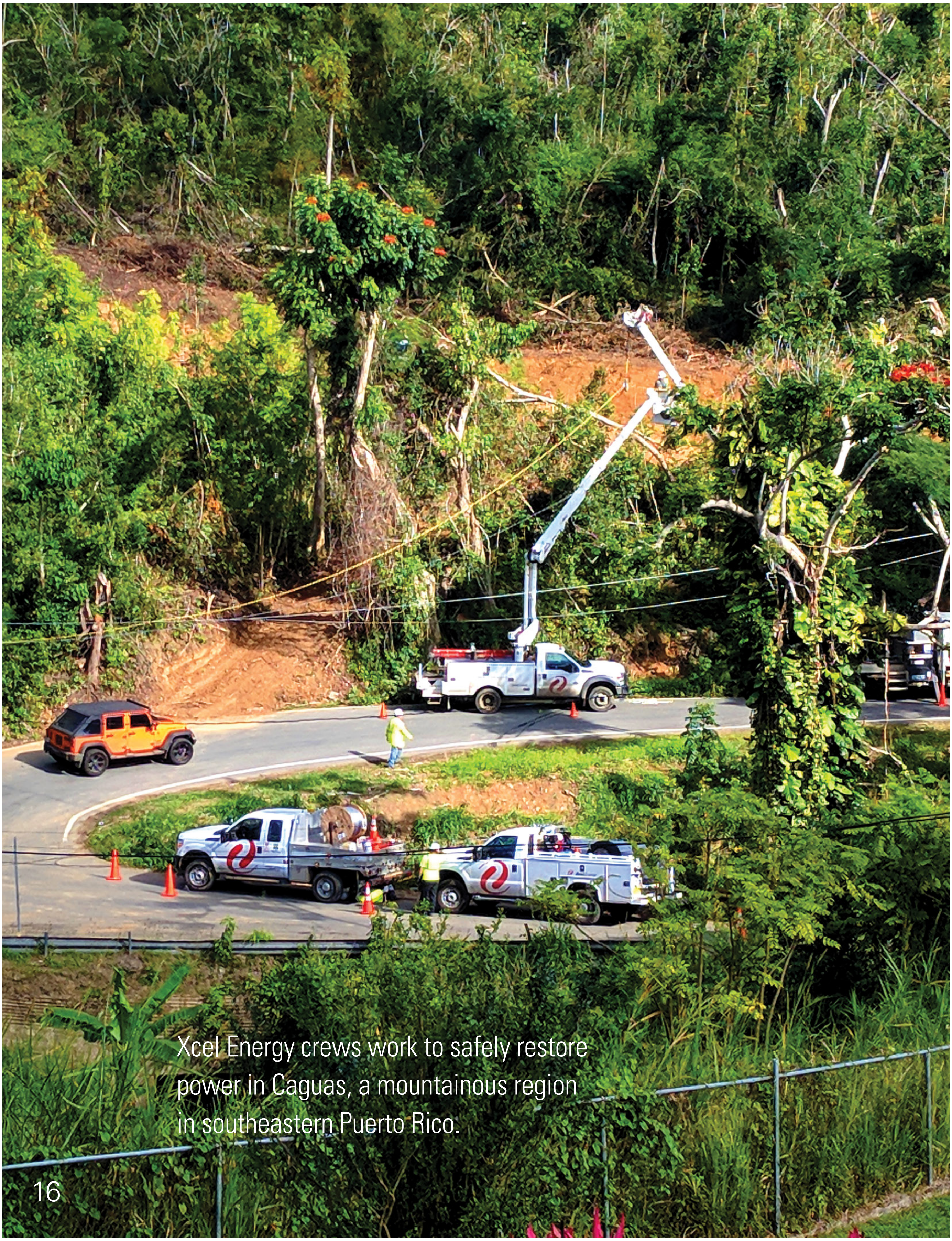
As a regulated utility, Xcel Energy is required to inspect and perform maintenance on its transmission lines — 24,000 miles of them — on a routine basis. Traditionally we have conducted these inspections with helicopters and foot patrols. Using drones to inspect transmission lines delivers value on many fronts, starting with ensuring the reliability for our customers thanks to better data capture.

It's also safer for our employees, especially in remote mountainous areas, and less expensive, which is one of the many ways we're working to keep customers' bills low. As technology improves, the cost to operate drones continues to fall, which saves even more money for customers.

Pending FAA approval, we plan to expand this program to inspect transmission lines in other states beginning in 2019. Additionally, we are collaborating with the FAA and the state of North Dakota on the National UAS Integration Pilot Program, an opportunity for state, local, and tribal governments to partner with private-sector entities to work together to accelerate drone integration.

Xcel Energy began using drones to conduct indoor inspections in 2013 and expanded the program for outdoor use in 2015. We use drones to inspect everything from boilers to wind towers to our nuclear facilities and everything in between.

Xcel Energy became the first public utility to receive permission from the Federal Aviation Administration to inspect transmission lines using drones flown beyond the operator's visual line of sight.



Xcel Energy crews work to safely restore power in Caguas, a mountainous region in southeastern Puerto Rico.

A powerful experience in Puerto Rico

Some of the most rewarding work of 2018 took place more than a thousand miles from our closest service territory. Approximately 200 Xcel Energy line workers and support personnel traveled to Puerto Rico to help restore power following the devastation of Hurricane Maria.

Three waves of Xcel Employees flew to Puerto Rico for three-week assignments on the Caribbean island, while our trucks and equipment arrived by barge after being driven to Lake Charles, Louisiana. Xcel Energy crews worked primarily in Caguas, a mountainous and remote region where restoration efforts were challenging due to rugged terrain, narrow roads and overgrown vegetation.

Crews worked 16-hour days to safely restore electricity for approximately 6,000 customers, including homes, schools, community centers and one church just in time to hold Easter services. Xcel Energy was among nearly 60 investor-owned electricity companies that collectively dispatched 3,000 line workers and support personnel to restore power as part of the industry's mutual aid program. Xcel Energy was one of several companies to be recognized with a special 2018 Emergency Assistance Award by the Edison Electric Institute.

"Traveling to Puerto Rico was one of the most rewarding experiences in my career," said Lee Nordby, who oversaw Xcel Energy's restoration efforts on the island. "Many of the people we encountered had been without power for three or four months, but they were so positive and grateful for our efforts."

Local residents thanked our crews with home-cooked meals, hugs and thank-you signs. One of the most moving events happened at a school where a 12-year-old cried tears of joy after we granted her birthday wish — to restore power after nearly five months in the dark.

"It was really powerful," said Mike Bulger, an operations manager from Colorado. "Our crews restore electricity all over the United States when called upon, but our experience in Puerto Rico was special — something that none of us will ever forget."

Xcel Energy co-sponsored an exhibition at Super Bowl LIVE, a week-long celebration that was powered by 100-percent renewable energy. The space included a display for children to illuminate the Super Bowl logo in lights.

Reliable power for the world's biggest stage

A few years ago, a power outage played a memorable role at the Super Bowl in New Orleans. Xcel Energy was determined to make sure that didn't happen in our backyard. As expected, Super Bowl LII between the Philadelphia Eagles and the New England Patriots went off without a hitch in downtown Minneapolis.

It was an honor to provide power for the biggest game on the world's biggest stage — more than 103 million people watched the game on television. Employees from our operations and security teams worked nearly two years performing reliability inspections, maintaining infrastructure, and identifying risk for every possible contingency leading up to the game that was played February 4, 2018 at U.S. Bank Stadium.

Xcel Energy proudly served as the official Renewable Energy Provider of the Minnesota Super Bowl Host Committee. All of the power needed for Super Bowl LIVE — a week-long celebration down the street from our corporate headquarters on Nicollet Mall — was powered through our WindSource® program with 100 percent of the energy coming from Minnesota wind farms. Xcel Energy and Vestas, our wind turbine manufacturing supplier, jointly sponsored an exhibition at Super Bowl LIVE that was staffed by our employee volunteers. More than a million people participated in a variety of events leading up to the big game.

We plan to use the same playbook to ensure things go smoothly during the next large sporting event in downtown Minneapolis — the NCAA Final Four men's basketball championship — that will take place at the same location in April 2019.

A thoughtful approach to building a diverse workforce

It's important for our workforce to reflect the diversity of the communities we are privileged to serve. We have taken a thoughtful approach to workforce development as we know that diverse organizations are more successful because they bring different strengths and perspectives to the table.

This includes expanding our award-winning internship programs, creating customized diverse hiring and retention plans for select business units, developing unconscious bias training for all employees and participating in the CEO Action for Diversity & Inclusion, a national program focused on diverse hiring and retention best practices.

For many years, we have been actively engaged with high school internship programs in the Twin Cities, Denver and Eau Claire, and we recently launched a new high school internship program in Amarillo, Texas. In 2018, we hired a record 66 high school interns, and the timing couldn't be better as it aligned with the launch of a new social media platform developed by Xcel Energy and Greater MSP to help Twin Cities companies to better track local interns and keep them in the pipeline for permanent employment.

We also partner with Legacy i3 — a unique program that encourages students from underrepresented communities to pursue careers in the energy industry and directs them to our educational partners who provide career training opportunities. This includes working with Minnesota State Colleges and Universities to guide these students into energy-related programs for line workers and technical specialists. Xcel Energy employees mentor these program participants through our Energy Ambassador program.

All these programs help us share with a broader audience our story that Xcel Energy is a great place to work, while we build candidate pipelines in communities where this story has not been well known in the past. Our high school and college internship programs have proven to be strong sources of diverse talent.

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, 2018
or

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

001-3034	**41-0448030**
(Commission File Number)	(I.R.S. Employer Identification No.)

(Registrant, State of Incorporation or Organization, Address of Principal Executive Officers and Telephone Number)

Xcel Energy Inc.

(a Minnesota corporation)
414 Nicollet Mall
Minneapolis, MN 55401
612-330-5500

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

Title of each class	Name of each exchange on which registered
Common Stock, $2.50 par value per share	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 and 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 if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 Act). ☐ Yes ☒ No

As of June 29, 2018, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $23,246,479,826 and there were 508,898,420 shares of common stock outstanding.

As of Feb. 14, 2019, there were 514,211,368 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2019 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

Item 1 — Business

ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
Capital Services	Capital Services, LLC
Eloigne	Eloigne Company
e prime	e prime inc.
NCE	New Century Energies, 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
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOJ	Department of Justice
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
IRS	Internal Revenue Service
Minnesota District Court	U.S. District Court for the District of Minnesota
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OAG	Minnesota Office of the Attorney General
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment Clauses	
CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
EIR	Environmental improvement rider
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy rider
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor
WCA	Windsource® cost adjustment

Other	
AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARAM	Average rate assumption method
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
ATM	At-the-market
ATRR	Annual transmission revenue requirement
BART	Best available retrofit technology
Boulder	City of Boulder, CO
C&I	Commercial and Industrial
CAPM	Capital Asset Pricing Model
CACJA	Clean Air Clean Jobs Act
CAISO	California Independent System Operator
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CBA	Collective-bargaining agreement
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
CEP	Colorado Energy Plan
CIG	Colorado Interstate Gas Company, LLC
CO_2	Carbon dioxide
Corps	U.S. Army Corps of Engineers
CPCN	Certificate of public convenience and necessity
CPP	Clean Power Plan
CWA	Clean Water Act

CWIP . . . . Construction work in progress
DCF . . . . Discounted Cash Flows
DECON . . . . Decommissioning method where radioactive contamination is removed and safely disposed at a requisite facility, or decontaminated to a permitted level.
DRC. . . . . Development Recovery Company
DRIP . . . . Dividend Reinvestment Program
EEI. . . . . Edison Electric Institute
ELG . . . . Effluent limitations guidelines
EMANI . . . . European Mutual Association for Nuclear Insurance
EPS . . . . Earnings per share
EPU . . . . Extended power uprate
ERP . . . . Electric resource plan
ETR . . . . Effective tax rate
FASB . . . . Financial Accounting Standards Board
FTR . . . . Financial transmission right
GAAP. . . . . Generally accepted accounting principles
GE . . . . General Electric
GHG . . . . Greenhouse gas
HDD. . . . . Heating degree-days
HTY . . . . Historic test year
IM. . . . . Integrated market
IPP. . . . . Independent power producing entity
IRC . . . . Internal Revenue Code
IRP. . . . . Integrated Resource Plan
ISFSI . . . . Independent Spent Fuel Storage Installation
ITC. . . . . Investment Tax Credit
JOA . . . . Joint operating agreement
LCM . . . . Life cycle management
LLW . . . . Low-level radioactive waste
LSP Transmission LSP Transmission Holdings, LLC
Mankato 1 . . . . . . Mankato Energy Center, LLC
Mankato 2 . . . . . . Mankato Energy Center II, LLC
MDL. . . . . Multi-district litigation
MGP . . . . Manufactured gas plant
MISO . . . . Midcontinent Independent System Operator, Inc.
Moody's . . . . Moody's Investor Services
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.
NETO. . . . . New England Transmission Owners
NOL . . . . Net operating loss
NOX. . . . . Nitrogen oxide
O&M . . . . Operating and maintenance
OATT . . . . Open Access Transmission Tariff
OCC. . . . . Office of Consumer Counsel
Opinion 531 . . . . . Methodology for calculating base ROE adopted by the FERC in June 2014
Paris Agreement . Establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions")
PI . . . . Prairie Island nuclear generating plant
PJM . . . . PJM Interconnection, LLC
PM . . . . Particulate matter
Post-65 . . . . Post-Medicare
PPA . . . . Purchased power agreement
Pre-65 . . . . Pre-Medicare
PRP . . . . Potentially responsible party
PTC . . . . Production tax credit
QF . . . . Qualifying facilities
R&E . . . . Research and experimentation
REC. . . . . Renewable energy credit
RFP . . . . Request for proposal
ROE. . . . . Return on equity
ROFR . . . . Right-of-first-refusal
RPS . . . . Renewable portfolio standards
RTO . . . . Regional Transmission Organization
Standard & Poor's . . . . Standard & Poor's Ratings Services
SAB . . . . Staff Accounting Bulletin
SAB 118. . . . . Income Tax Accounting Implications of the Tax Cuts and Jobs Act
SERP. . . . . Supplemental executive retirement plan
SMMPA . . . . Southern Minnesota Municipal Power Agency
SO2 . . . . Sulfur dioxide
SPP . . . . Southwest Power Pool, Inc.
SSL . . . . Statistically significant increase over established groundwater standards
TCEH. . . . . Texas Competitive Energy Holdings
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
TOs . . . . Transmission owners
TransCo. . . . . Transmission-only subsidiary
TSR . . . . Total shareholder return
VaR . . . . Value at Risk
VIE. . . . . Variable interest entity
WOTUS . . . . Waters of the U.S.

Measurements

Bcf . . . . Billion cubic feet
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 the 2019 EPS guidance, long-term EPS and dividend growth rate, 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, 2018 (including the items described under Factors Affecting Results of Operations; and the other 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: 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; ability of subsidiaries 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 and their impact on capital expenditures and 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; operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

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.

COMPANY OVERVIEW

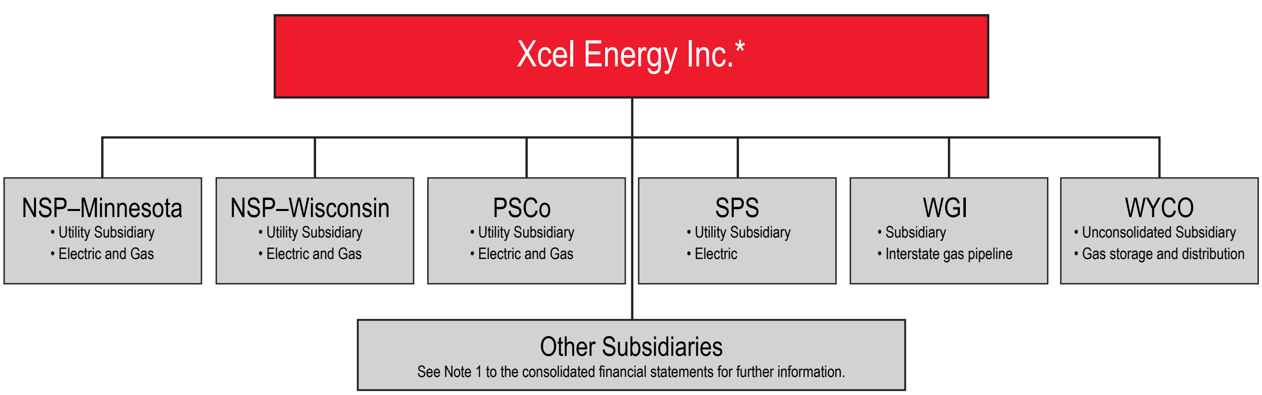
Xcel Energy Inc. and its subsidiaries (“Xcel Energy” or the “Company”) is a major U.S. regulated electric and natural gas delivery company which serves customers in eight mid-western and western states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. The Company provides a comprehensive portfolio of energy-related products and services to approximately 3.6 million electric customers and 2.0 million natural gas customers through four operating companies (e.g., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS).

Xcel Energy‘s vision is to be the preferred and trusted provider of the energy our customers need and we strive to provide our investors an attractive total return value proposition and customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via three key strategic priorities:

- Lead the clean energy transition;
- Enhance the customer experience; and,
- Keep the bills low.

Xcel Energy is an environmental leader and in 2018 was the first major utility in the nation to announce a vision to serve all customers with 100% zero-carbon emissions by 2050. The Company is also implementing the nation’s largest multi-state wind plan with 12 new, low-cost wind farms across seven states. By leading the clean energy transition, we have positioned ourselves to create economic development for the communities and customers we serve.

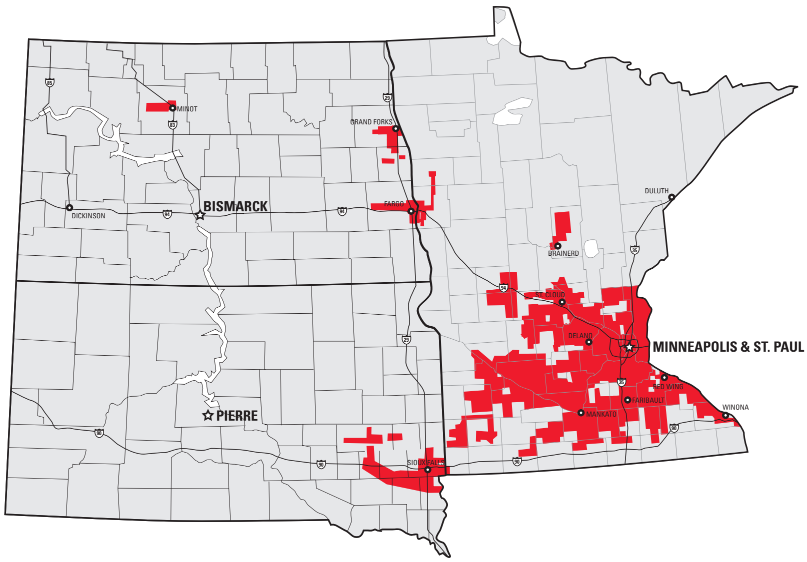
See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Management’s Strategic Priorities for further discussion.



* Holding company incorporated under the laws of Minnesota in 1909 and its executive offices are located at 414 Nicollet Mall, Minneapolis, MN 55401.

NSP-Minnesota

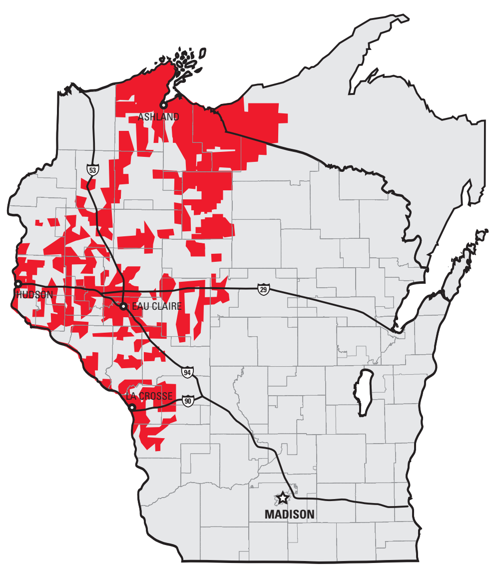
NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity as managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells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



NSP-Minnesota	
Electric customers	1.5 million
Natural gas customers	0.5 million
Consolidated earnings contribution .	35% to 45%
Total assets	$18.5 billion
Electric generating capacity	7,530 MW
Gas storage capacity	14.7 Bcf

NSP-Wisconsin

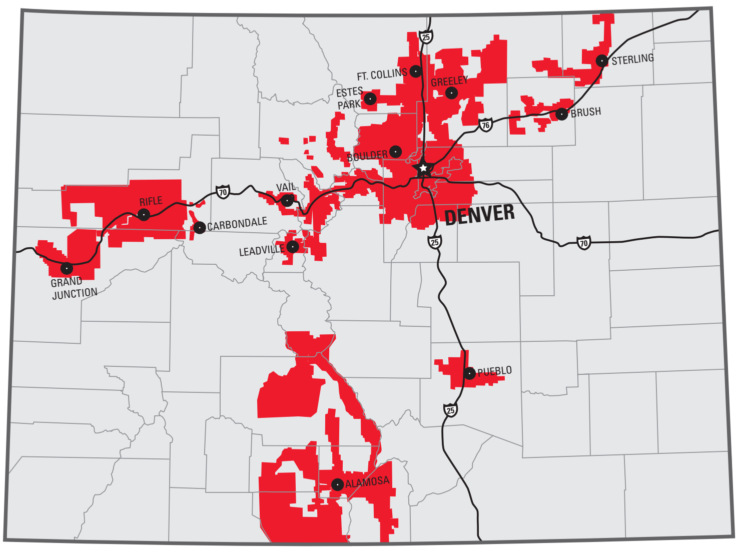
NSP-Wisconsin conducts business in Wisconsin and Michigan and generates, transmits, distributes and sells electricity as managed on the NSP System. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.



NSP-Wisconsin	
Electric customers	0.3 million
Natural gas customers	0.1 million
Consolidated earnings contribution .	5% to 10%
Total assets	$2.7 billion
Electric generating capacity	563 MW
Gas storage capacity	3.6 Bcf

PSCo

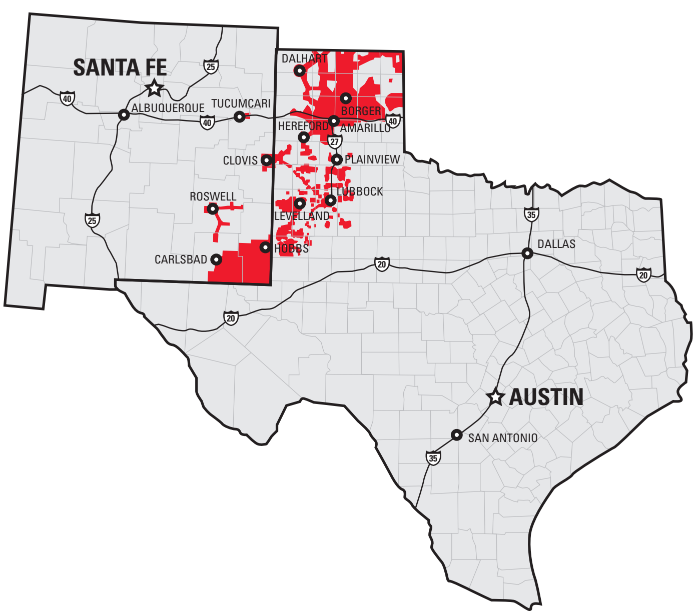
PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity in addition to purchasing, transporting, distributing and selling natural gas to retail customers and transporting customer-owned natural gas.



PSCo	
Electric customers	1.5 million
Natural gas customers	1.4 million
Consolidated earnings contribution .	35% to 45%
Total assets	$17.3 billion
Electric generating capacity	5,685 MW
Gas storage capacity	27.1 Bcf

SPS

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



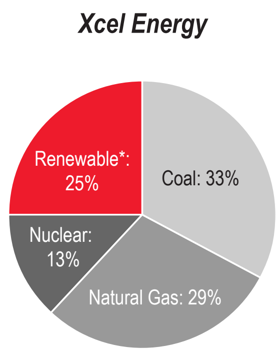
SPS	
Electric customers	0.4 million
Consolidated earnings contribution .	15% to 20%
Total assets	$6.7 billion
Electric generating capacity	4,406 MW

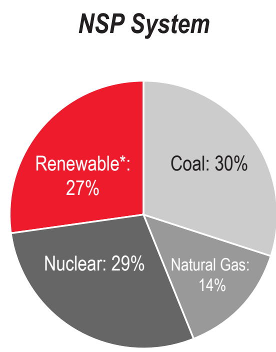
ELECTRIC UTILITY OPERATIONS

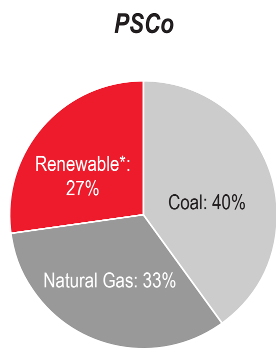
Electric Operating Statistics

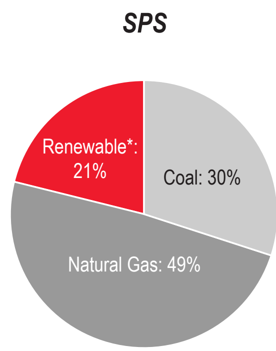
	Year Ended Dec. 31		
	2018	2017	2016
Electric sales (Millions of KWh)			
Residential	25,518	24,216	24,726
Large C&I	28,686	27,951	27,664
Small C&I	36,308	35,493	35,830
Public authorities and other	1,071	1,055	1,103
Total retail	91,583	88,715	89,323
Sales for resale	24,199	18,349	18,694
Total energy sold	115,782	107,064	108,017
Number of customers at end of period			
Residential	3,117,262	3,082,974	3,053,732
Large C&I	1,253	1,241	1,228
Small C&I	436,836	433,883	432,012
Public authorities and other	69,794	69,376	68,935
Total retail	3,625,145	3,587,474	3,555,907
Wholesale	70	58	52
Total customers	3,625,215	3,587,532	3,555,959
Electric revenues (Millions of Dollars)			
Residential	$ 3,006	$ 2,975	$ 2,966
Large C&I	1,696	1,779	1,707
Small C&I	3,343	3,463	3,328
Public authorities and other	136	143	140
Total retail	8,181	8,360	8,141
Wholesale	801	719	693
Other electric revenues	737	597	666
Total electric revenues	$ 9,719	$ 9,676	$ 9,500
KWh sales per retail customer	25,263	24,729	25,120
Revenue per retail customer	$ 2,257	$ 2,330	$ 2,289
Residential revenue per KWh	11.78¢	12.29¢	11.99¢
Large C&I revenue per KWh	5.91	6.36	6.17
Small C&I revenue per KWh	9.21	9.76	9.29
Total retail revenue per KWh	8.93	9.42	9.11
Wholesale revenue per KWh	3.31	3.92	3.71

Energy Sources 2018









*Distributed generation from the Solar*Rewards® program is not included (approximately 432 million KWh for 2018).

Energy Source Statistics

	Xcel Energy	NSP System	PSCo	SPS
2018				
Owned Generation	67%	77%	70%	49%
Purchased Generation	33	23	30	51
	100%	100%	100%	100%
2017				
Owned Generation	66%	75%	70%	47%
Purchased Generation	34	25	30	53
	100%	100%	100%	100%

Renewable Sources

Xcel Energy's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2018, each utility or system was in compliance with their applicable RPS. Renewable percentages will vary year over year based on local weather, system demand and transmission constraints.

NSP System

Renewable energy as a percentage of the NSP System's total:

	2018	2017
Wind	16.4%	18.3%
Hydroelectric	5.8	6.3
Biomass and solar	4.8	4.2
Renewable	27.0%	28.8%

Wind — The NSP System has more than 130 PPAs ranging from under one MW to more than 200 MW. The NSP System owns and operates five wind farms with 840 MW, net, of capacity.

- The NSP System had approximately 2,550 MW and 2,600 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under existing PPAs was approximately $44 for 2018 and 2017.
- Average cost per MWh of wind energy from owned generation was approximately $37 and $42 for 2018 and 2017, respectively.

PSCo

Renewable energy as a percentage of PSCo's total:

	2018	2017
Wind	23.8%	23.7%
Hydroelectric and solar	3.6	3.9
Renewable	27.4%	27.6%

Wind — PSCo has 19 PPAs ranging from two MW to over 300 MW. PSCo owns and operates the Rush Creek wind farm which has 600 MW, net, of capacity.

- PSCo had approximately 3,160 MW and 2,560 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under these contracts was approximately $43 and $42 for 2018 and 2017, respectively.
- Rush Creek became operational in December 2018. The 2019 average cost per MWh is expected to be $29.

SPS

Renewable energy as a percentage of SPS' total:

	2018	2017
Wind	19.1%	21.2%
Solar	2.0	2.8
Renewable	21.1%	24.0%

Wind — SPS has 18 PPAs with facilities ranging from under one MW to 250 MW.

- SPS had approximately 1,565 MW and 1,500 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under the IPP contracts and QF tariffs was approximately $26 and $27 for 2018 and 2017, respectively.
- In 2018, SPS began construction on the Sagamore and Hale County wind farms. Refer to the SPS Wind Development section for further information.

Non-Renewable Sources

Delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation and the percentage of total fuel requirements represented by each category of fuel:

	Coal (a)		Nuclear		Natural Gas	
	Cost	Percent	Cost	Percent	Cost	Percent
NSP System						
2018	$ 2.13	42%	$ 0.80	45%	$ 3.87	13%
2017	2.08	45	0.78	45	4.10	10
PSCo						
2018	1.45	62	—	—	3.74	38
2017	1.56	70	—	—	3.82	30
SPS						
2018	2.04	56	—	—	2.24	44
2017	2.18	74	—	—	3.39	26

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

Weighted average cost per MMBtu of all fuels for owned electric generation:

	NSP System	PSCo	SPS
2018	$ 1.78	$ 2.33	$ 2.13
2017	1.72	2.25	2.50

See Items 1A and 7 for further information.

Coal — Inventory maintained (in days):

	Normal	Dec. 31, 2018 Actual	Dec. 31, 2017 Actual (a)
NSP System	35 - 50	47	53
PSCo	35 - 50	48	48
SPS	35 - 50	44	52

(a) Milder weather, purchase commitments and low power and natural gas prices impacted coal inventory levels.

Coal requirements (in million tons):

	2018	2017
NSP System	7.8	8.0
PSCo	9.4	10.0
SPS	5.1	5.5

Coal supply as a percentage of requirements (in million tons) for 2019:

	Contracted Coal Supply	2019 Estimated Requirements
NSP System (a)	76%	(b) 8.4
PSCo (a)	83	8.4
SPS (a)	64	4.1

(a) The general coal purchasing objective is to contract for approximately 75% of first year requirements, 40% of year two requirements and 20% of year three requirements.

(b) Increase in estimated million tons was due to lower delivered coal prices at Sherco in January 2019, combined with higher future forecasted gas prices for 2019 (higher burn forecast).

Contracted coal transportation as a percentage of requirements in 2019 and 2020:

	2019	2020
NSP System	100%	100%
PSCo	100	100
SPS	100	100

Natural Gas — 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.

Contracts and commitments at Dec. 31:

	NSP System		PSCo		SPS	
(Millions of Dollars)	Gas Supply	Gas Transportation and Storage (a)	Gas Supply (b)	Gas Transportation and Storage (a)	Gas Supply	Gas Transportation and Storage (a)
2018	$ —	$ 406	$ 412	$ 589	$ 20	$ 152
2017	—	398	545	620	11	191
Year of Expiration	N/A	2020 - 2037	2021 - 2023	2019 - 2040	One year or less	2019 - 2033

(a) For incremental supplies, there are limited on-site fuel storage facilities, with a primary reliance on the spot market.

(b) Majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services Company and the balance of natural gas supply contracts have variable pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 10 to the consolidated financial statements for further information.

Nuclear — NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100% of uranium concentrates requirements through 2021 and approximately 51% of the requirements for 2022 - 2033.
- Current contracts for conversion services cover 100% of the requirements through 2021 and approximately 43% of the requirements for 2022 - 2033.
- Current enrichment service contracts cover 100% of the requirements through 2025 and approximately 19% of the requirements for 2026 - 2033.

Fabrication services for Monticello and PI are 100% committed through 2030 and 2027, respectively.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the requirements of its nuclear generating plants. Some exposure to market price volatility will remain due to index-based pricing structures contained in supply contracts.

See Item 7 for further information.

Capacity and Demand

Uninterrupted system peak demand and date for the regulated utilities:

	System Peak Demand (in MW)			
	2018		2017	
NSP System [(a)]	8,927	June 29	8,546	July 17
PSCo [(a)].	6,718	July 10	6,671	July 19
SPS [(a)].	4,648	July 19	4,374	July 26

(a) Peak demand typically occurs in the summer. The increase in peak load from 2017 to 2018 is partly due to warmer weather in 2018.

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, NDPSC and SDPUC. The MPUC also has regulatory authority over security issuances, certain property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's IRPs for meeting future energy needs. In addition, MPUC certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC for its 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.

NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and MISO 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.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms —

- *CIP rider* — Recovers the costs of conservation and demand-side management programs.
- *EIR* — Recovers the costs of environmental improvement projects.
- *RDF* — Allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — Recovers the cost of renewable generation in Minnesota.
- *RER* — Recovers the cost of renewable generation located in North Dakota.
- *SEP* — Recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — Recovers costs associated with investments in electric transmission and distribution grid modernization costs.
- *Infrastructure rider* — Recovers costs for investments in generation and incremental property taxes in South Dakota.

NSP-Minnesota's retail electric rates in 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. Costs associated with MISO are generally recovered through either the FCA or base rates.

In 2017, the MPUC voted to change the FCA process in Minnesota. Under the new process, each month utilities would collect amounts equal to the baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to the baseline costs would be tracked and netted over a 12-month period. Utilities would issue refunds above the baseline costs, and could seek recovery of any overage. Recently, the MPUC delayed implementation until January 2020.

Minnesota state law requires NSP-Minnesota to invest 2% of its state electric revenues and 0.5% of its state gas revenues in CIP. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

Energy Sources 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 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.

Wind Development — In 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation including ownership of 1,150 MW of wind generation.

In April 2018, the MPUC approved NSP-Minnesota's petition to build and own the Dakota Range, a 300 MW wind project in South Dakota. NSP-Minnesota's capital investment for the Dakota Range is expected to be approximately $350 million and placed in service in 2021.

In December 2018, the NDPSC approved a settlement agreement for these wind development projects.

PPA Terminations and Amendments — In June 2018, NSP-Minnesota terminated the Benson and Laurentian PPAs, and purchased the Benson biomass facility. As a result, a $103 million regulatory asset was recognized for the costs of the Benson transaction. For Laurentian, a regulatory asset of $109 million was recognized for annual termination payments/obligations. Regulatory approvals provide for recovery of the Benson regulatory asset over 10 years and Laurentian termination payments as they occur (over six years). Termination of the PPAs is expected to save customers over $600 million throughout the next 10 years.

Jurisdictional Cost Recovery Allocation — In December 2016, NSP-Minnesota filed a resource treatment framework with the NDPSC and MPUC. The filing proposed a framework to allow NSP-Minnesota's operations in North Dakota and Minnesota to gradually become more independent of one another with respect to future generation resource selection while also identifying a path for cost sharing of current resources. NSP-Minnesota's filing identified two options: a legal separation, creating a separate North Dakota operating company; or a pseudo-separation, which maintains the current corporate structure but directly assigns the costs and benefits of each resource to the jurisdiction that supports it. Docket remains under consideration by the NDPSC.

Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, MPUC and DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from near Mankato, Minnesota to Winnebago, Minnesota. The project was estimated by MISO to cost $108 million and was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss. In June 2018, the Minnesota District Court granted the defendants' motions to dismiss with prejudice. LSP Transmission filed an appeal in July 2018. It is uncertain when a decision will be rendered.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes which are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

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 in customer rates and expects future compliance costs will continue to be recoverable.

LLW Disposal — LLW from NSP-Minnesota's Monticello and PI nuclear plants is currently disposed at the Clive facility located in Utah and the Waste Control Specialists facility located in Texas. If off-site LLW disposal facilities become unavailable, 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.

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. The federal government has been evaluating a nuclear geologic repository at Yucca Mountain, Nevada for many years. Currently, there are no definitive plans for a permanent federal storage facility at Yucca Mountain or any other site.

Review of PI Costs — As part of NSP-Minnesota's 2016 multi-year electric rate case and IRP, the MPUC ordered an investigation into NSP-Minnesota's PI nuclear investments. The issue was resolved as part of the 2016 multi-year electric rate case settlement. In November 2018, the DOC issued a final report, in which no cost disallowances were recommended.

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.

In 2013, NSP-Minnesota's Monticello nuclear generating plant loaded and placed five storage canisters (canisters #11-15) in the ISFSI and a sixth canister (canister #16) was loaded but remained in the plant pending resolution of weld inspection issues. Successful pressure and leak testing demonstrated the safety and integrity of all six canisters involved. NSP-Minnesota took several actions to assure compliance with the NRC's regulations and Monticello's storage license. The NRC has approved NSP-Minnesota's compliance plan for all canisters.

NSP-Minnesota intends to seek recovery of these costs in a future regulatory proceeding. No public safety issues have been raised, or are believed to exist, in this matter.

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

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts various 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 hedge sales and purchases. NSP-Minnesota also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC for its 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. 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.

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.

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause. Instead, under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW. Once the PSCW approves the fuel cost 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 utility's most recently authorized ROE. Fuel cost under-collections that exceed the 2% annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.

NSP-Wisconsin's electric fuel costs for 2018 were lower than authorized in rates and outside the 2% annual tolerance band, primarily due to greater than forecasted generation sales into the MISO market and lower purchased power costs coupled with moderate weather. Under the fuel cost recovery rules, NSP-Wisconsin retained approximately $3.6 million of fuel costs and deferred approximately $2.8 million. NSP-Wisconsin will file a reconciliation of 2018 fuel costs with the PSCW by March 31, 2019.

NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are 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 state's utilities, but operated by independent contractors subject to oversight by the PSCW and utilities. NSP-Wisconsin recovers these costs from retail customers.

Transmission Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota-Energy Sources and Transmission Service Provider.

NSP-Wisconsin / American Transmission Company, LLC - La Crosse to Madison, WI Transmission Line — In December 2018, construction was completed on the Badger Coulee 345 KV transmission line. The line extends from La Crosse, WI. to Madison, WI. NSP-Wisconsin's half of the line is shared with Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

Wholesale and Commodity Marketing Operations

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

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC for its 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. 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. PSCo makes 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 as authorized by the FERC.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms

- *ECA* — Recovers fuel and purchased energy costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.
- *PCCA* — Recovers purchased capacity payments.
- *SCA* — Recovers the difference between PSCo's actual cost of fuel and costs recovered under its steam service rates. The SCA rate is revised quarterly.
- *DSMCA* — Recovers DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
- *RESA* — Recovers the incremental costs of compliance with the RES with a maximum of 2% of the customer's bill.
- *WCA* — Recovers costs for customers who choose renewable resources.
- *TCA* — Recovers costs for transmission investment outside of rate cases.
- *CACJA* — Recovers costs associated with the CACJA.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay their jurisdictional allocation of production costs through a fully forecasted formula rate with true-up.

Energy Sources 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.

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.

Wind Development — In 2018, PSCo completed construction and placed in service its Rush Creek 600 MW wind farm in Colorado.

CEP — In September 2018, the CPUC approved PSCo's preferred CEP portfolio, which included the retirement of two coal-fired generation units, Comanche Unit 1 (in 2022) and Comanche Unit 2 (in 2025), and the following additions:

	Total Capacity	PSCo's Ownership
Wind generation	1,100 MW	500 MW
Solar generation	700 MW	—
Battery storage	275 MW	—
Natural gas generation	380 MW	380 MW

PSCo's investment is expected to be approximately $1 billion, including transmission to support the increase in renewable generation. This investment includes the 500 MW Cheyenne Ridge wind farm and 345 KV generation tie line, as well as the Shortgrass Substation. CPCNs for these projects were filed in December 2018. A CPUC decision is anticipated by May 2019. CPCNs for the natural gas generation facility are anticipated to be filed by mid-2019.

Boulder Municipalization — In 2011, Boulder passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Subsequently, there have been various legal proceedings in multiple venues with jurisdiction over Boulder's plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility and the Colorado Court of Appeals ruled in PSCo's favor, vacating a lower court decision. In June 2018, the Colorado Supreme court rejected Boulder's request to dismiss the case and remanded it to the Boulder District Court.

Boulder has filed multiple separation applications with the CPUC, which have been challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo's position. The CPUC has approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain filings. Those filings were submitted in the fourth quarter of 2018. Subsequently, various parties requested the CPUC commence additional processes; the form of such processes is currently under consideration. In the fourth quarter of 2018, Boulder's City Council also adopted an Ordinance authorizing Boulder to begin negotiations for the acquisition of certain property or to otherwise condemn that property after Feb. 1, 2019. In the first quarter of 2019, Boulder sent PSCo a Notice of Intent to acquire certain electric distribution assets.

Boulder does not have authorization from the CPUC to initiate a condemnation proceeding at this time.

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 and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.

SPS is regulated by the FERC for its 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. SPS is a transmission-owning member of the SPP RTO and operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms —

- *DCRF* — Recovers distribution costs not included in rates in Texas.
- *EECRF* — Recovers costs for energy efficiency programs in Texas.
- *EE rider* — Recovers costs for energy efficiency programs in New Mexico.
- *FPPCAC* — Adjusts monthly to recover the actual fuel and purchased power costs in New Mexico.
- *PCRF* — Allows recovery of purchased power costs not included in rates in Texas.
- *RPS* — Recovers deferred costs for renewable energy programs in New Mexico.
- *TCRF* — Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in base rates in Texas.

The fixed fuel and purchased energy recovery factor provides for the over- or under-recovery of energy expenses. 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.

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.

Energy Sources and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements. In addition, it has evaluated water supply issues at the Tolk facility, concluding additional resource investment will be required to operate the plant through its existing life. The Ogallala aquifer has depleted more rapidly than expected. SPS installed a horizontal water well that may help delay the need for a more substantial investment solution. As a result of this issue and future environmental rules facing the plant, it sought a decrease to the remaining life of the facility in the 2017 Texas and New Mexico rate case proceedings.

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.

Wind Development — In 2018, the NMPRC and PUCT approved SPS' proposal to add 1,230 MW of new wind generation, including 1,000 MW ownership.

In March 2018, the NMPRC approved SPS' petition to build and own Sagamore, a 522 MW wind project in New Mexico which is expected to be placed into service in 2020. In May 2018, the PUCT approved SPS' petition to build and own Hale County, a 478 MW wind project in Texas which is expected to be placed into service in 2019. Both projects qualify for 100% of PTCs. SPS' capital investment for these wind projects is expected to be approximately $1.6 billion.

Texas State ROFR Request for Declaratory Order — In 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility the ROFR to construct new transmission facilities located in the utility's service area. The PUCT subsequently issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities. In January 2018, SPS and two other parties filed appeals in the Texas State District Court. In September 2018, the District Court affirmed the PUCT's ROFR order. SPS has filed an additional appeal.

NATURAL GAS UTILITY OPERATIONS

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2018	2017	2016
Natural gas deliveries (Thousands of MMBtu)			
Residential	149,036	134,189	132,853
C&I	96,447	87,271	84,082
Total retail	245,483	221,460	216,935
Transportation and other	173,092	142,497	133,498
Total deliveries	418,575	363,957	350,433
Number of customers at end of period			
Residential	1,878,576	1,856,221	1,835,507
C&I	158,424	157,798	157,286
Total retail	2,037,000	2,014,019	1,992,793
Transportation and other	7,951	7,705	7,316
Total customers	2,044,951	2,021,724	2,000,109
Natural gas revenues (Millions of Dollars)			
Residential	$ 1,045	$ 1,006	$ 930
C&I	556	524	469
Total retail	1,601	1,530	1,399
Transportation and other	138	120	132
Total natural gas revenues	$ 1,739	$ 1,650	$ 1,531
MMBtu sales per retail customer	120.51	109.96	108.86
Revenue per retail customer	$ 786	$ 760	$ 702
Residential revenue per MMBtu	7.01	7.50	7.00
C&I revenue per MMBtu	5.76	6.00	5.58
Transportation and other revenue per MMBtu	0.80	0.84	0.99

Capability and Demand

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

Maximum daily send-out (firm and interruptible) and occurrence date:

	2018		2017	
Utility Subsidiary	MMBtu	Date	MMBtu	Date
NSP-Minnesota	786,751 (a)	Jan. 12	893,062	Dec. 26
NSP-Wisconsin	159,700	Jan. 5	160,170	Dec. 26
PSCo	1,903,878 (a)	Feb. 20	1,948,167	Jan. 5

(a) Decrease in MMBtu output due to milder winter temperatures in 2018.

Natural gas is purchased from independent suppliers, generally based on market indices that reflect current prices, and is delivered under transportation agreements with interstate pipelines.

Contracted firm deliverable pipeline capacity as of Dec. 31:

Utility Subsidiary	MMBtu Per Day
NSP-Minnesota	645,171
NSP-Wisconsin	140,195
PSCo	1,834,843 (a)

(a) Includes 871,418 MMBtu of natural gas under third-party underground storage agreements.

The utility subsidiaries contract with providers of underground natural gas storage services. Agreements provided storage of winter natural gas and peak day firm requirements for 2018 as follows:

Utility Subsidiary	Percent of Winter Requirements	Peak Day Firm Requirements
NSP-Minnesota	24%	29%
NSP-Wisconsin	30	33

PSCo also operates three company-owned underground storage facilities, which provide approximately 43,500 MMBtu of natural gas on peak days. The balance required to meet firm peak day sales obligations is primarily purchased at PSCo's city gate meter stations.

Natural Gas Supply and Costs

Xcel Energy actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio which provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their respective state commissions.

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

	NSP-Minnesota	NSP-Wisconsin	PSCo
2018	$ 4.03	$ 3.84	$ 3.20
2017	3.89	3.88	3.45

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. As of Dec. 31, 2018, the utility subsidiaries had the following contractual obligations:

- NSP-Minnesota — $437 million (expire 2019 - 2033);
- NSP-Wisconsin — $89 million (expire 2019 - 2029); and,
- PSCo — $1.1 billion (expire 2019 - 2029).

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's retail natural gas operations are regulated by the MPUC and NDPSC. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. The MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is also subject to the DOT, Minnesota Office of Pipeline Safety, NDPSC and SDPUC for pipeline safety compliance.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period.

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — NSP-Wisconsin is regulated by the PSCW and MPSC. 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 period beginning the following January.

NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce. NSP-Wisconsin is subject to the DOT, PSCW and MPSC for pipeline safety compliance.

Natural Gas Cost-Recovery Mechanisms — NSP-Wisconsin has a retail PGA cost-recovery mechanism for Wisconsin to recover the actual cost of natural gas and transportation and storage services.

NSP-Wisconsin's natural gas rates for Michigan customers include a natural gas cost-recovery factor, which is based on 12-month projections and trued-up to actual amounts on an annual basis.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction. PSCo is subject to the DOT and CPUC with regards to pipeline safety compliance.

Purchased Natural Gas and Conservation Cost-Recovery Mechanisms

- *GCA* — Recovers the costs of purchased natural gas and transportation to meet customer requirements and is revised quarterly to allow for changes in natural gas rates.
- *DSMCA* — Recovers costs of DSM and performance initiatives to achieve various energy savings goals.
- *PSIA* — Recovers costs for transmission and distribution pipeline integrity management programs.

SPS

Natural Gas Facilities Used for Electric Generation

SPS does not provide retail natural gas service, but purchases and transports natural gas for its generation facilities and operates 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.

GENERAL

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.

See Item 7 for further information.

Competition

Xcel Energy is a vertically integrated utility subject to traditional cost-of-service regulation by state public utilities commissions. 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, but not limited to, 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 policies designed to promote the development of solar and other distributed energy resources through incentive policies. With these incentives and federal tax subsidies, distributed generating resources are potential competitors to Xcel Energy's electric service business.

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

FERC Order No. 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. State utilities commissions have also created resource planning programs that promote competition for electricity generation resources used to provide service to retail customers.

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 of Xcel Energy Inc.'s utility subsidiaries faces these challenges, Xcel Energy believes their rates and services are competitive with the alternatives currently available.

ENVIRONMENTAL MATTERS

Xcel Energy's facilities are regulated by federal and state environmental agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy's facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon Xcel Energy's operations. Xcel Energy will likely be required to incur capital expenditures in the future to comply with requirements for remediation of MGP and other legacy sites. The scope and timing of these expenditures cannot be determined until more information is obtained regarding the need for remediation at legacy sites.

In Minnesota, Texas and Wisconsin, Xcel Energy must comply with emission budgets that require the purchase of emission allowances from other utilities. The Denver North Front Range Nonattainment Area does not meet either the 2008 or 2015 ozone NAAQS. Colorado will continue to consider further reductions available in the non-attainment area as it develops plans to meet ozone standards. Gas plants which operate in PSCo's non-attainment area may be required to improve or add controls, implement further work practices and/or implement enhanced emissions monitoring as part of future Colorado state plans.

There are significant present and future environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. Xcel Energy 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. If future environmental regulations do not provide credit for the investments Xcel Energy has already made or if they require additional initiatives or emission reductions, substantial costs may be incurred. The EPA, as an alternative to the CPP, has proposed a new regulation that, if adopted, would require implementation of heat rate improvement projects at our coal-fired power plants. It is not known what those costs might be until a final rule is adopted and state plans are developed to implement a final regulation. Xcel Energy believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Starting in 2011, Xcel Energy began reporting GHG emissions under the EPA's mandatory GHG Reporting Program.

Xcel Energy estimates that in 2018, it reduced the CO_2 emissions associated with the electric generating resources used to serve its customers by approximately 40% from 2005 levels. This reduction accounts for emissions from electric generating plants owned by Xcel Energy as well as purchased power.

Xcel Energy primarily relied on strategies that resulted in:

- Development of renewable energy facilities;
- Retirement and replacement of existing generating plants; and,
- Customer energy efficiency programs.

CAPITAL SPENDING AND FINANCING

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

EMPLOYEES

As of Dec. 31, 2018, Xcel Energy had 11,043 full-time employees and 49 part-time employees, of which 5,129 were covered under CBAs.

	Employees Covered by CBAs	Total Employees
NSP-Minnesota	2,064	3,278
NSP-Wisconsin	386	540
PSCo	1,904	2,426
SPS	775	1,151
XES	—	3,697
Total	5,129	11,092

EXECUTIVE OFFICERS [(a)]

Name	Age [(b)]	Current and Recent Positions Held	Time in Position
Ben Fowke	60	Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2011 - Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	January 2015 - Present
Brett C. Carter	52	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	October 2015 - May 2018
		Senior Vice President and Chief Operating Officer, Bank of America	March 2015 - October 2015
		Senior Vice President and Chief Distribution Officer, Duke Energy Co.	February 2013 - March 2015
Christopher B. Clark	52	President and Director, NSP-Minnesota	January 2015 - Present
		Regional Vice President, Rates and Regulatory Affairs, NSP-Minnesota	October 2012 - December 2014
David L. Eves	60	Executive Vice President and Group President, Utilities, Xcel Energy Inc.	March 2018 - Present
		President and Director, PSCo	January 2015 - February 2018
		President, Director and Chief Executive Officer, PSCo	December 2009 - December 2014
Darla Figoli	56	Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer, Xcel Energy Inc.	May 2018 - Present
		Senior Vice President, Human Resources and Employee Services, Xcel Energy Inc.	May 2015 - May 2018
		Vice President, Human Resources, Xcel Energy Inc.	February 2010 - May 2015
Robert C. Frenzel	48	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 - Present
		Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. [(c)]	February 2012 - April 2016
David T. Hudson	58	President and Director, SPS	January 2015 - Present
		President, Director and Chief Executive Officer, SPS	January 2014 - December 2014
Alice Jackson	40	President and Director, PSCo	May 2018 - Present
		Area Vice President, Strategic Revenue Initiatives, Xcel Energy Services Inc.	November 2016 - May 2018
		Regional Vice President, Rates and Regulatory Affairs, PSCo	October 2011 - November 2016
Kent T. Larson	59	Executive Vice President and Group President Operations, Xcel Energy Inc.	January 2015 - Present
		Senior Vice President, Group President Operations, Xcel Energy Services Inc.	August 2014 - December 2014
		Senior Vice President Operations, Xcel Energy Services Inc.	September 2011 - August 2014
Timothy O'Connor	59	Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc.	February 2013 - Present
Judy M. Poferl	59	Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc.	January 2015 - Present
		Vice President, Corporate Secretary, Xcel Energy Inc.	May 2013 - December 2014
Jeffrey S. Savage	47	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 - Present
		Vice President, Controller, Xcel Energy Inc.	September 2011 - December 2014
Mark E. Stoering	58	President and Director, NSP-Wisconsin	January 2015 - Present
		President, Director and Chief Executive Officer, NSP-Wisconsin	January 2012 - December 2014
Scott M. Wilensky	62	Executive Vice President, General Counsel, Xcel Energy Inc.	January 2015 - Present
		Senior Vice President, General Counsel, Xcel Energy Inc.	September 2011 - December 2014

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

(b) Ages as of Dec. 31, 2018.

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

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. These risks should be carefully considered together with the other information set forth in this report and future reports that Xcel Energy files with the SEC.

Oversight of Risk and Related Processes

A key accountability of the Board of Directors is the oversight of material risk, and our Board of Directors employs an effective process for doing so. Management and each Board of Directors' committee have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and analysis occurs formally through a key risk assessment conducted by senior management, the financial disclosure process, hazard risk management procedures and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. The business planning process also identifies areas in which there is a potential for a business area to assume inappropriate risk to meet goals and determines how to prevent inappropriate risk-taking.

Xcel Energy has a robust compliance program and promotes a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. Xcel Energy manages and further mitigates risks through formal risk management structures, including management councils, risk committees and services of corporate areas such as internal audit, corporate controller and legal.

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 which provides information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability.

The Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of Xcel Energy. The Board of Directors regularly reviews management's key risk assessment and analyzes areas of existing and future risks and opportunities. In addition, the Board of Directors assigns oversight of critical risks to its four committees to ensure these risks are well understood and given appropriate focus. The Audit Committee is responsible for reviewing the adequacy of risk oversight and affirming that appropriate oversight occurs. Oversight of cybersecurity risks by the Operations, Nuclear, Environmental and Safety Committee includes receiving independent outside assessments of cybersecurity maturity and assessment of plans.

New risks are considered and assigned as appropriate during the annual Board of Directors' and committee evaluation process. Committee charters and annual work plans are updated accordingly. 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. Finally, the Board of Directors conducts an annual strategy session where Xcel Energy's future plans and initiatives are reviewed.

Risks Associated with Our Business

Operational Risks

Our natural gas and electric 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 transmission and distribution activities also include inherent hazards and operating risks such as contact, fire and outages which could cause substantial financial losses. These natural gas and electric risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial losses. We maintain insurance against some, 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.

Additionally, for natural gas costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant.

The Pipeline Safety Act requires verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

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.

Our utility operations are subject to long-term planning 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 when they are brought in-service 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.

The electric utility sector is undergoing a period of significant change. For example, increases in appliance, lighting and energy efficiency, wider adoption and lower cost of renewable generation and distributed generation, shifts away from coal generation to decrease CO_2 emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources as well as stranded costs if Xcel Energy is not able to fully recover the costs and investments. These changes also introduce additional uncertainty into long-term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide and that the preference for the types of additions may change from planning to execution. In addition, we are subject to longer-term availability of the natural resource 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.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure. This increases the exposure to potential outdating of technologies and resultant risks. The inability of coal mining companies to attract capital could disrupt longer-term supplies. Decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation places downward pressure on sales growth. This may lead to under recovery of costs, excess resources to meet customer demand and increases in electric rates. Finally, multiple states may not agree as to the appropriate resource mix and the differing views may lead to costs incurred to comply with one jurisdiction that are not recoverable across all of the jurisdictions served by the same assets.

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

NSP-Minnesota's two nuclear stations, PI and Monticello, subject it to the risks of nuclear generation, which include:

- Risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal of radioactive materials;
- Limitations on insurance available to cover losses that might 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; and,
- Uncertainties with the technological and financial aspects of decommissioning nuclear plants. For example, assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset 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. The NRC has the authority to impose fines and/or shut down a unit until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the Institute for Nuclear Power Operations reviews NSP-Minnesota's nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

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

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota. NSP-Wisconsin may be subject to risks associated with NSP-Minnesota's nuclear generation.

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

If fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause 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. Low fuel costs have a positive impact on sales, however low oil and natural gas prices could negatively impact oil and gas production activities and subsequently our sales volumes and revenue.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Significantly higher energy or fuel costs relative to sales commitments have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and could cause disruptions in our ability to provide electric and/or natural gas services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process.

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. Actual settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

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 earn a return on our capital investment. Our rates are generally regulated and based on an analysis of the utility's costs incurred in a test year. Our 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. In a continued low interest rate environment there has been pressure pushing down ROE. 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. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements of utility facilities and while regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs leaving all or a portion of these asset costs stranded. Higher than expected inflation or tariffs may increase costs of construction and operations. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers, or these factors could cause the operating utilities to exceed commitments made regarding cost caps and result in less than full recovery. Overall, management currently believes prudently incurred costs are recoverable given the existing regulatory mechanisms in place.

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 our 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 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, significantly lower returns on equity or equity ratios or impacts of tax policy changes 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 downgrade could lead to higher borrowing costs and could impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require the posting of collateral or settlement of applicable contracts 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 markets are global and impacted by issues and events throughout the world. Capital market disruption events 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.

Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning and/or pension funds, as well as our ability to earn a return on short-term investments of excess cash.

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 overall economy and local economies in the geographic areas we serve, including local unemployment rates.

Credit risk also includes the risk that various counterparties that owe us money or product will become insolvent and/or 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 at times 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, such as CAISO, SPP, PJM, MISO and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants.

We have additional indirect credit exposures to financial institutions in the form of 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 related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving could trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid.

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

Our self-insured costs of health care benefits for eligible employees have increased in recent years. 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. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

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

We are a holding company and 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. Also, our utility subsidiaries are regulated by state utility commissions, which possess broad powers to ensure that the needs of the utility customers are being met.

If our 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.

Federal tax law may significantly impact our business.

Xcel Energy's utility subsidiaries collect through regulated rates estimated federal, state and local tax payments. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Changes to tax depreciable lives and the value of various tax credits may change the economics of resources and our resource selections. There could be timing delays before regulated rates provide for realization of the tax changes in revenues. In addition, certain IRS tax policies such as the requirement to utilize 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. Growth in customers and sales are correlated with economic conditions.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to additional bad debt expense.

Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may impact our ability to acquire sufficient supplies. We operate in a capital intensive industry and federal policy on trade could significantly impact the cost of materials we use. We could be at risk for higher costs for materials and our workforce. There may be delays before these additional costs can be recovered in rates.

Our operations could be impacted by war, acts of terrorism, and threats of terrorism or disruptions due to 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, our 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 or an event (e.g., severe storm, severe temperature extremes, wildfires, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

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.

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 begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. 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 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 may expose software or hardware to these risks and could result in a breach or significant costs of remediation. In addition, such an event would likely receive federal and state regulatory scrutiny. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential 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 the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems or those of our third-party service providers were to fail or be breached, we may be unable to fulfill critical business functions. We are unable to quantify the potential impact of cyber security incidents on our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network monitoring 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.

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

We rely on third party contractors to perform work for operations, maintenance and construction. We have contractual arrangements with these contractors which typically include performance standards, progress payments, insurance requirements and security for performance.

Cyber security breaches have at times exploited third party equipment or software in order to gain access. Poor vendor performance could impact on going operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

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 and new interpretations of existing laws create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system.

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

Although the United States has not adopted any international or federal GHG emission reduction targets, many states and localities may continue to pursue climate policies in the absence of federal mandates. All of the steps that 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. While those actions likely would have put Xcel Energy in a good position to meet federal or international standards being discussed, the lack of federal action does not adversely impact these state-endorsed actions and plans.

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. Additionally, the PHMSA, Occupational Safety and Health Administration and other federal agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

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, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities.

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 (i.e., clean-up) sites where our past activities, or the activities of other parties, caused environmental contamination.

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 the 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. Extreme weather conditions in general require system backup, costs, 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.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. 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 and increase the price paid for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's 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.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota, NSP-Wisconsin, SPS and PSCo is subject to the lien of their first mortgage bond indentures.

Electric Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511
Sherco-Becker, MN			
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 - 2002	494 [(d)]
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	453
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	282
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454
Various locations, 14 Units	Natural Gas	Various	67
Wind:			
Border-Rolette County, ND, 75 Units	Wind	2015	148 [(e)]
Courtenay Wind, ND, 100 Units	Wind	2016	195 [(e)]
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	101 [(e)]
Nobles-Nobles County, MN., 134 Units	Wind	2010	200 [(e)]
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196 [(e)]
		Total	7,530

(a) Summer 2018 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Black Dog Unit 6 was commissioned and placed into operation in the third quarter of 2018.
(e) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Bay Front-Ashland, WI, 3 Units	Coal/Wood/Natural Gas	1948 - 1956	56
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	563

(a) Summer 2018 net dependable capacity.
(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	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	968
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580
Various locations, 6 Units	Natural Gas	Various	171
Hydro:			
Cabin Creek-Georgetown, CO			
Pumped Storage, 2 Units	Hydro	1967	210
Various locations, 9 Units	Hydro	Various	26
Wind:			
Rush Creek, CO, 300 units	Wind	2018	600 [(g)]
		Total	5,685

(a) Summer 2018 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 is expected to be retired early in 2025.
(e) Based on PSCo's ownership of 10%.
(f) Based on PSCo's ownership of 75% of Unit 1 and 37% of Unit 2.
(g) Generation capability is based on the maximum output level of wind units, including the Rush Creek Wind Project. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

SPS

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	251
Harrington-Amarillo, TX, 3 Units	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	411
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1998	209
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, TX, 1 Unit	Natural Gas	1963 - 1976	61
		Total	4,406

(a) Summer 2018 net dependable capacity.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2018:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	13,560	3,415	4,062	9,028
230 KV	2,202	—	12,053	9,675
161 KV	615	1,823	—	—
138 KV	—	—	91	—
115 KV	7,372	1,817	5,051	14,493
Less than 115 KV	86,185	32,831	78,446	25,820

Electric utility transmission and distribution substations at Dec. 31, 2018:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	348	203	232	459

Natural gas utility mains at Dec. 31, 2018:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	90	3	2,080	20	11
Distribution	10,437	2,466	22,518	—	—

Item 3 — Legal Proceedings

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessment of whether a loss is probable or is a reasonable possibility, and whether a loss or a range of loss is estimable, often involves a series of complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) damages sought are indeterminate, (2) proceedings are in the early stages or (3) 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.

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 was listed on the New York Stock Exchange (NYSE) in 2017, but moved to the Nasdaq Global Select Market (Nasdaq) in 2018. The trading symbol is XEL. The number of common stockholders of record as of Dec. 31, 2018 was approximately 57,059.

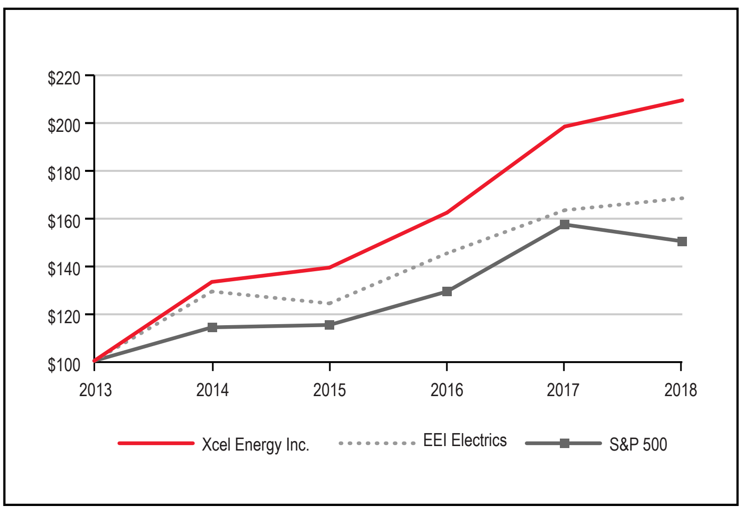
See Item 7 for further information.

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the Standard & Poor's 500 Composite Stock Price Index over the last five years (assuming a $100 investment on Dec. 31, 2013, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 42 companies at year-end and is a broad measure of industry performance.

COMPARISON OF FIVE YEAR CUMULATIVE TOTAL RETURN*

Xcel Energy Inc., the EEI Investor-Owned Electrics and the Standard & Poor's 500



* $100 invested on Dec. 31, 2013 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2018 Annual Meeting of Shareholders, which is incorporated by reference.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2018, 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 — Selected Financial Data

Selected financial data for Xcel Energy related to the five most recent years ended Dec. 31.

(Millions of Dollars, Millions of Shares, Except Per Share Data)	2018	2017	2016	2015	2014
Operating revenues	$ 11,537	$ 11,404	$ 11,107	$ 11,024	$ 11,686
Operating expenses [(a)]	9,572	9,181	8,867	9,024	9,738
Net income	1,261	1,148	1,123	984	1,021
Earnings available to common shareholders	1,261	1,148	1,123	984	1,021
Diluted earnings per common share	2.47	2.25	2.21	1.94	2.03
Financial information					
Dividends declared per common share	1.52	1.44	1.36	1.28	1.20
Total assets [(b) (c)]	45,987	43,030	41,155	38,821	36,958
Long-term debt [(c) (d)]	15,803	14,520	14,195	12,399	11,500

(a) As a result of adopting ASU No. 2017-07 (*Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715),* $33 million and $26 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the consolidated statements of income for the years ended Dec. 31, 2017 and Dec. 31, 2016, respectively.

(b) As a result of adopting ASU No. 2015-17 (*Balance Sheet Classification of Deferred Taxes, Topic 740*), $140 million of current deferred income taxes was retrospectively reclassified to long-term deferred income tax liabilities on the consolidated balance sheet as of Dec. 31, 2015.

(c) As a result of adopting ASU No. 2015-03 (*Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30*), $92 million of deferred debt issuance costs was retrospectively reclassified from other non-current assets to long-term debt on the consolidated balance sheet as of Dec. 31, 2015.

(d) Includes capital lease obligations.

Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations

Business Segments and Organizational Overview

Xcel Energy Inc. is a public utility holding company. Xcel Energy's operations include the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. The utility subsidiaries serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with the utility subsidiaries, the TransCo 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 Inc.'s immaterial nonregulated subsidiaries are Eloigne and Capital Services.

Management's Strategic Priorities

Xcel Energy's vision is to be the preferred and trusted provider of the energy our customers need. We strive to provide our investors an attractive value proposition and our customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via three key strategic priorities:

- Lead the clean energy transition;
- Enhance the customer experience; and,
- Keep bills low.

Successful execution of our strategic objectives should allow Xcel Energy to continue to deliver a competitive total return for our shareholders.

Lead the clean energy transition

For more than a decade, we have managed the risk of climate change and increasing customer demand for renewable energy through a clean energy strategy that consistently reduces carbon emissions and transitions our operations for the future. As a result, we have successfully reduced our carbon emissions to our customers by approximately 40% from 2005 to 2018. We expect to reduce our carbon footprint by 80% by 2030 (over 2005 levels). We have also announced our vision to serve all customers with 100% zero-carbon emissions by 2050.

Our service territories benefit from the geographic concentration of favorable renewable resources. Strong wind and high solar irradiance yield high generation capacity factors, which lowers the cost of these resources. The combination of high capacity factors, grid options from transmission investment and market operations, improved supply chain, technological improvements and the extension of the renewable tax credits translates into low renewable energy costs for our customers. As a result, we are able to invest in renewable generation, in which the capital costs are largely or completely offset by fuel savings. This provides us the opportunity to lower the emission profile of our generation fleet, grow our renewable portfolio and provide significant fuel savings to our customers. We call this our "Steel for Fuel" strategy.

We are transitioning how we produce, deliver and encourage the efficient use of energy through four primary mechanisms:

- Increasing the use of affordable renewable energy;
- Offering energy efficiency programs for customers;
- Retiring or repowering coals units and modernizing our generating plants; and,
- Advancing power grid capabilities.

We have announced ambitious plans to add approximately 3,600 MW of wind energy on our system by 2021.

In addition, the proposed CEP in Colorado encompasses the retirement of 660 MW from two coal-fired units at Comanche and the addition of up to 1,100 MW of wind, 700 MW of solar and 275 MW of battery storage.

Enhance the customer experience

The utility landscape is changing, and we must continue to thoughtfully anticipate and address the future needs of our stakeholders, including our customers, policymakers, employees and shareholders. Our customers expect to have choices, and we are committed to providing options and solutions that they want and value at a competitive price.

We will continue to expand our production of renewable energy, including wind and solar alternatives, and further develop and promote DSM, conservation and renewable programs. We are also in the process of transforming our transmission and distribution systems to accommodate increased levels of renewables, distributed energy resources and corresponding data growth, while maintaining high levels of reliability and security and keeping customer bills affordable. We also are expanding our Renewable*Connect program, which allows customers to choose how much of their energy comes from renewable sources. Renewable*Connect has regulatory approval in Minnesota, Colorado and Wisconsin. This is yet another way for us to add renewable energy and meet the needs of our customers. Importantly, Renewable*Connect does not negatively impact the bills of non-participants. Finally, we are improving our communications to enable customers to interact with us in the way they prefer.

Keep bills low

Xcel Energy is very focused on our customers and the impact our actions have on their bill. Our objective is to keep total bill increases at or below the rate of inflation so our prices remain competitive relative to alternatives. We expect to continue to keep our customer bills low by executing on our Steel for Fuel plan, controlling O&M costs and promoting energy efficiency and conservation.

Xcel Energy is working to keep long-term O&M expense relatively consistent without compromising reliability or safety. We intend to accomplish this objective by continually improving our processes, leveraging technology, proactively managing risk and maintaining a workforce that is prepared to meet the needs of our business today and tomorrow. In 2018, we experienced warmer than normal summer weather, which caused us to spend additional O&M for vegetation management and system maintenance due to the hot summer, business systems costs, investments to improve and enhance business processes and customer service, as well as damage prevention and remediation costs. However, we remain committed to our long-term objective of improving operating efficiencies and taking costs out of the business for the benefit of our customers and anticipate that our long-term O&M expense trend will remain relatively consistent.

Provide a competitive total return to investors and maintain strong investment grade credit rating

Through our disciplined approach to business growth, financial investment, operations and safety, we plan to:

- Deliver long-term annual EPS growth of 5% to 7%;
- Deliver annual dividend increases of 5% to 7%;
- Target a dividend payout ratio of 60% to 70% of annual ongoing EPS; and,
- Maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range.

We have consistently achieved our financial objectives, meeting or exceeding our earnings guidance range for fourteen consecutive years, and we believe we are positioned to continue to deliver on our value proposition. Our ongoing earnings have grown approximately 6.1% and our dividend has grown approximately 4.5% annually from 2005 - 2018. In addition, our current senior unsecured debt credit ratings for Xcel Energy and its utility subsidiaries are in the BBB+ to A range, while our secured operating company debt ratings are in the A range.

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 the ongoing return on equity (ROE), electric margin, natural gas margin, 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.

Electric and Natural Gas Margins

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

Management believes electric and natural gas 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, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

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 year ended Dec. 31, 2017, Xcel Energy recognized an estimated one-time, non-cash, income tax expense of approximately $23 million for net excess deferred tax assets which may not be recovered from customers or not attributable to regulated operations, increased valuation allowances, etc. due to the enactment of the TCJA in December 2017. For the year ended Dec. 31, 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

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

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

	2018	2017			2016
Diluted Earnings (Loss) Per Share	GAAP and Ongoing Diluted EPS	GAAP Diluted EPS	Impact of TCJA [(a)]	Ongoing Diluted EPS	GAAP and Ongoing Diluted EPS
PSCo	$ 1.08	$ 0.97	$ (0.03)	$ 0.94	$ 0.91
NSP-Minnesota	0.96	0.96	0.05	1.01	0.96
SPS	0.42	0.31	(0.01)	0.30	0.30
NSP-Wisconsin	0.19	0.16	—	0.16	0.14
Equity earnings of unconsolidated subsidiaries [(a)]	0.04	0.07	(0.04)	0.03	0.05
Regulated utility [(b)]	2.69	2.47	(0.03)	2.45	2.35
Xcel Energy Inc. and other	(0.22)	(0.22)	0.07	(0.15)	(0.15)
Total [(b)]	$ 2.47	$ 2.25	$ 0.05	$ 2.30	$ 2.21

(a) Includes income taxes.
(b) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating the company 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.

Earnings Adjusted for Certain Items

2018 Comparison with 2017

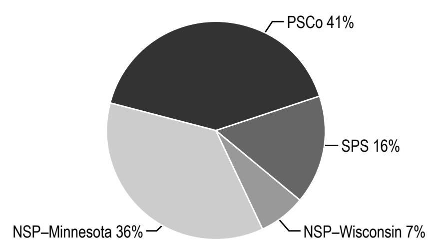
2017 Adjustment to GAAP Earnings — Impact of the TCJA — Xcel Energy recognized an estimated one-time, non-cash, income tax expense of approximately $23 million in the fourth quarter of 2017 for net excess deferred tax assets which may not be recovered from customers or not attributable to regulated operations, increased valuation allowances, etc. due to the enactment of the TCJA in December 2017. The income tax expense associated with the TCJA enactment has been excluded from Xcel Energy's 2017 ongoing earnings, given the non-recurring nature of the TCJA's broad and sweeping reform of the IRC.

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

Differences between GAAP and ongoing earnings are due to the non-recurring impact of the TCJA experienced in 2017. Explanations for operating company results below exclude the offsetting impacts of the TCJA on sales, depreciation and amortization expense and income tax.

Xcel Energy — GAAP and ongoing earnings increased $0.22 and $0.17 per share, respectively. Earnings increased as a result of higher electric and natural gas revenues primarily due to favorable weather and sales growth and higher AFUDC. These positive factors were partially offset by increased O&M, depreciation and interest expenses. GAAP earnings for 2017 include the non-recurring negative impact of the TCJA.

2018 Ongoing Diluted EPS



PSCo — GAAP and ongoing 2018 earnings increased $0.11 and $0.14 per share, respectively. Increases were driven by higher natural gas margins largely due to a natural gas rate increase, higher electric margins reflecting favorable weather and sales growth, and additional AFUDC associated with the Rush Creek wind project. These items were partially offset by higher O&M expenses, interest charges, depreciation expense and property taxes.

NSP-Minnesota — 2018 GAAP earnings were consistent with 2017, while 2018 ongoing earnings decreased $0.05 per share. The decrease in ongoing earnings reflects higher depreciation expense and O&M expenses. These amounts were partially offset by higher electric and natural gas margins attributable to favorable weather.

SPS — 2018 GAAP and ongoing earnings increased $0.11 and $0.12 per share, respectively. Increases were primarily due to higher electric margins reflecting favorable weather and sales growth and a rate increase in New Mexico, AFUDC related to the Hale County wind project and lower interest charges. Increases were partially offset by higher depreciation expense.

NSP-Wisconsin — 2018 GAAP and ongoing earnings increased $0.03 per share. Increases reflect higher electric and natural gas rates and the impact of favorable weather and sales growth, which were partially offset by higher depreciation.

Xcel Energy Inc. and other — Xcel Energy Inc. and other primarily includes financing costs at the holding company. 2018 GAAP earnings were consistent with 2017, while 2018 ongoing earnings decreased $0.07 per share. Decrease was primarily due to higher interest expense related to additional debt and the change in the federal income tax rate.

2017 Comparison with 2016

Xcel Energy — GAAP earnings increased $0.04 per share for 2017. Ongoing earnings increased $0.09 per share, excluding the impact of the TCJA. Earnings were higher as a result of increased electric and natural gas margins to recover infrastructure investments, reduced O&M expenses, a lower ETR and higher AFUDC. These positive factors were partially offset by increased depreciation expense, interest charges and property taxes.

PSCo — GAAP earnings increased $0.06 per share for 2017. Ongoing earnings increased $0.03 per share, excluding the impact of the TCJA. The increase in earnings was driven by higher electric and natural gas margins, increased AFUDC primarily related to the Rush Creek wind project, a decrease in O&M expenses (timing of generation outages) and a lower ETR, partially offset by higher depreciation expense, interest charges and the impact of unfavorable weather.

NSP-Minnesota — GAAP earnings were flat for 2017. Ongoing earnings increased $0.05 per share, excluding the impact of the TCJA. The change reflects higher electric margins driven by a 2017 Minnesota rate increase as well as increased gas margins, a lower ETR and reduced O&M expenses. These positive factors were partially offset by higher depreciation expense due to increased invested capital as well as prior year amortization of Minnesota's excess depreciation reserve and higher property taxes.

SPS — GAAP earnings increased $0.01 per share for 2017. Ongoing earnings were flat, excluding the impact of the TCJA. Rate increases in Texas and New Mexico and a lower ETR were offset by higher depreciation expense (representing continued investment), O&M expenses (including the prior year deferrals associated with the Texas 2016 rate case), property taxes and the impact of unfavorable weather.

NSP-Wisconsin — GAAP and ongoing earnings increased $0.02 per share for 2017. The change in ongoing earnings was driven by a rise in electric and natural gas rates, partially offset by additional depreciation expense related to continued transmission and distribution investments and higher O&M expenses.

Equity earnings of unconsolidated subsidiaries — GAAP earnings increased $0.02 per share for 2017. Ongoing earnings of unconsolidated subsidiaries decreased $0.02 per share, excluding the impact of the TCJA. The decline primarily related to lower revenues due to lower rates at WYCO.

Changes in Diluted EPS

Components significantly contributing to changes in 2018 EPS compared with the same period in 2017 and 2017 EPS compared to 2016:

2018 vs. 2017

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP diluted EPS — 2017	**$ 2.25**
Impact of the TCJA [(a)]	0.05
Ongoing diluted EPS — 2017	**$ 2.30**
Components of change — 2018 vs. 2017	
Higher electric margins (excluding TCJA impacts) [(a)]	0.31
Higher natural gas margins (excluding TCJA impacts) [(a)]	0.13
Higher AFUDC — equity	0.07
Higher O&M expenses	(0.10)
Higher depreciation and amortization (excluding TCJA impacts) [(a)]	(0.10)
Higher ETR (excluding TCJA impacts) [(a)]	(0.07)
Higher interest charges	(0.04)
Higher conservation and demand side management (DSM) program expenses (offset by higher revenues)	(0.02)
Higher taxes (other than income taxes)	(0.01)
GAAP and ongoing diluted EPS — 2018	**$ 2.47**
Estimated net impact of the TCJA, including assumptions regarding future regulatory proceedings: [(a)]	
Income tax — rate change and ARAM (net of deferral)	0.68
Electric margin reductions (net)	(0.46)
Natural gas margin reductions (net)	(0.06)
Depreciation and amortization reductions (Colorado prepaid pension)	(0.11)
Holding company — interest expense	(0.04)
Total	$ 0.01

2017 vs. 2016

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP and ongoing diluted EPS — 2016	**$ 2.21**
Components of change — 2017 vs. 2016	
Higher electric margins [(a)]	0.16
Lower ETR [(b)]	0.07
Higher natural gas margins	0.03
Higher AFUDC — equity	0.03
Lower O&M expenses	0.03
Higher depreciation and amortization	(0.21)
Higher conservation and DSM program expenses [(c)]	(0.03)
Higher interest charges	(0.02)
Higher taxes (other than income taxes)	(0.02)
Equity earnings of unconsolidated subsidiaries	(0.02)
Other, net	0.02
GAAP diluted EPS — 2017	**$ 2.25**
Impact of the TCJA	0.05
Ongoing diluted EPS — 2017	**$ 2.30**

(a) Includes an increase of $23 million in revenues from conservation and DSM programs, offset by related expenses, for the twelve months ended Dec. 31, 2017.

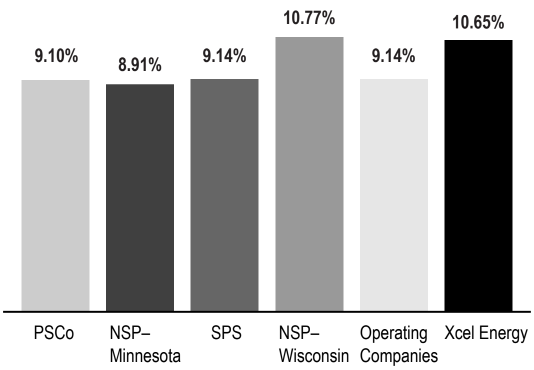
(b) ETR includes the impact of an additional $20 million of wind PTCs for the twelve months ended Dec. 31, 2017, which are largely flowed back to customers through electric margin, as well as the impact of the TCJA recorded in the fourth quarter of 2017.

(c) Offset by higher revenues.

ROE for Xcel Energy and its utility subsidiaries at Dec. 31:

	2018	2017		
ROE	GAAP and Ongoing ROE	GAAP ROE	Impact of the TCJA	Ongoing ROE
PSCo	9.10%	8.90%	(0.24)%	8.66%
NSP-Minnesota	8.91	9.05	0.45	9.50
SPS	9.14	7.84	(0.30)	7.54
NSP-Wisconsin	10.77	9.41	0.09	9.50
Operating Companies	9.14	8.84	0.03	8.87
Xcel Energy	10.65	10.21	0.21	10.42

2018 Ongoing Return on Equity



Reconciliation of GAAP earnings (net income) to ongoing earnings and GAAP diluted EPS to ongoing diluted EPS for the years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
GAAP earnings	$ 1,261	$ 1,148	$ 1,123
Estimated impact of TCJA	—	23	—
Ongoing earnings	$ 1,261	$ 1,171	$ 1,123

Diluted EPS	2018	2017	2016
GAAP diluted EPS	$ 2.47	$ 2.25	$ 2.21
Estimated impact of TCJA	—	0.05	—
Ongoing diluted EPS	$ 2.47	$ 2.30	$ 2.21

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 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 and the amount of natural gas or electricity historically used per degree of temperature. Weather deviations from normal levels can affect Xcel Energy's financial performance.

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 20-year 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 increase (decrease) in normal and actual HDD, CDD and THI:

	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2016 vs. Normal	2017 vs. 2016
HDD	2.2%	(10.0)%	12.2%	(13.4)%	2.6%
CDD	26.7	6.5	20.5	11.1	(3.5)
THI	37.3	(11.3)	56.9	7.7	(18.5)

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

	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2016 vs. Normal	2017 vs. 2016
Retail electric	$ 0.114	$ (0.036)	$ 0.150	$ 0.004	$ (0.040)
Firm natural gas	0.007	(0.023)	0.030	(0.025)	0.002
Total (excluding decoupling)	$ 0.121	$ (0.059)	$ 0.180	$ (0.021)	$ (0.038)
Decoupling — Minnesota electric	(0.051)	0.022	(0.073)	(0.002)	0.024
Total (adjusted for recovery from decoupling)	$ 0.070	$ (0.037)	$ 0.107	$ (0.023)	$ (0.014)

Sales Growth (Decline) — Sales growth (decline) for actual and weather-normalized sales in 2018 compared to the same period in 2017:

	2018 vs. 2017				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	3.6%	5.8%	8.6%	5.7%	5.4%
Electric C&I	1.5	1.1	5.4	3.2	2.4
Total retail electric sales	2.2	2.5	5.9	3.9	3.2
Firm natural gas sales	9.3	14.6	N/A	13.1	11.3

	2018 vs. 2017				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	1.8%	(0.5)%	2.0%	0.2%	0.8%
Electric C&I.	1.2	(0.4)	4.6	2.3	1.5
Total retail electric sales . .	1.3	(0.4)	4.1	1.7	1.3
Firm natural gas sales	2.2	2.7	N/A	3.1	2.4

Weather-normalized 2018 Electric Sales Growth (Decline)

- PSCo — Higher residential sales growth reflects customer additions and slightly higher use per customer. C&I growth was due to an increase in customers and higher use per customer, predominately from the fabricated metal, food products, metal mining and oil and gas extraction industries.
- NSP-Minnesota — Residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in C&I sales was due to an increase in customers offset by lower use per customer. Increased sales to large customers in manufacturing and energy were offset by declines in services.
- SPS — Residential sales grew largely due to higher use per customer and customer additions. The increase in C&I sales was driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin — Sales growth was primarily attributable to customer additions, partially offset by lower use per customer. C&I growth was largely due to higher use per large customer, customer additions and increased sales to sand mining and energy industries.

Weather-normalized 2018 Natural Gas Sales Growth

- Higher natural gas sales reflect an increase in the number of customers combined with increasing customer use.

	2017 vs. 2016				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(1.8)%	(2.1)%	(3.5)%	(0.8)%	(2.1)%
Electric C&I.	(0.1)	(1.4)	1.3	2.2	(0.1)
Total retail electric sales . .	(0.6)	(1.6)	0.2	1.3	(0.7)
Firm natural gas sales	(2.2)	9.3	N/A	11.3	2.1

	2017 vs. 2016				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	(1.6)%	(0.7)%	(1.2)%	0.3 %	(1.0)%
Electric C&I.	0.1	(1.0)	1.5	2.5	0.2
Total retail electric sales . .	(0.4)	(1.0)	0.9	1.8	(0.2)
Firm natural gas sales	0.6	4.7	N/A	5.7	2.2

	2017 vs. 2016 (Excluding Leap Day) [b]				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential [a]	(1.3)%	(0.5)%	(1.0)%	0.6%	(0.8)%
Electric C&I.	0.3	(0.8)	1.8	2.7	0.4
Total retail electric sales . .	(0.2)	(0.7)	1.1	2.1	0.1
Firm natural gas sales	1.1	5.2	N/A	6.3	2.7

(a) Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized and actual growth (decline) estimates.

(b) Estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. Estimated impact of the additional day of sales in 2016 was approximately 0.3% for retail electric and 0.5% for firm natural gas for the twelve months ended.

Weather-normalized 2017 Electric Sales Growth (Decline) (Excluding Leap Day)

- PSCo's decline in residential sales reflects lower use per customer, partially offset by customer additions. C&I growth was mainly due to an increase in customers and higher use for large C&I customers that support the mining, oil and natural gas industries, partially offset by lower use for the small C&I class.
- NSP-Minnesota's residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in C&I sales was largely due to reduced usage, which offset an increase in the number of customers. Declines in services more than offset increased sales to large customers in manufacturing and energy industries.
- SPS' residential sales fell largely due to lower use per customer. The increase in C&I sales reflects customer additions and greater use for large C&I customers driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin's residential sales increase was primarily attributable to higher use per customer and customer additions. C&I growth was largely due to higher use per customer and increased sales to customers in the sand mining industry and large customers in the energy and manufacturing industries.

Weather-normalized 2017 Natural Gas Sales Growth

- Higher natural gas sales reflect an increase in the number of customers, partially offset by a decline in customer use.

Weather-normalized sales for 2019 are projected to be relatively consistent with 2018 levels for retail electric customers and within a range of 0.0% to 1.0% over 2018 levels for retail natural gas customers.

Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. Electric margin was reduced by approximately $105 million in 2018 and $130 million in 2017 for PTCs (grossed up for federal income tax) which were returned to customers. Margin reductions for PTCs are largely offset by income tax benefits.

Electric revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017	2016
Electric revenues before TCJA impact	$ 10,046	$ 9,676	$ 9,500
Electric fuel and purchased power before TCJA impact	(3,867)	(3,757)	(3,718)
Electric margin before TCJA impact	$ 6,179	$ 5,919	$ 5,782
TCJA impact (offset as a reduction in income tax)	(314)	—	—
Electric margin	$ 5,865	$ 5,919	$ 5,782

Electric Margin

(Millions of Dollars)	2018 vs. 2017
Estimated impact of weather (net of Minnesota decoupling)	$ 63
Retail sales growth (net of Minnesota decoupling and sales true-up)	52
Non-fuel riders	45
Purchased capacity costs	38
Wholesale transmission revenue (net)	31
Retail rate increase (Wisconsin, New Mexico and Michigan)	20
Other (net)	11
Total increase in electric margin before TCJA impact	$ 260
TCJA impact (offset as a reduction in income tax)	(314)
Total decrease in electric margin	$ (54)

(Millions of Dollars)	2017 vs. 2016
Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin)	$ 123
Non-fuel riders	33
Conservation and DSM revenues (offset by expenses)	23
Decoupling (weather portion — Minnesota)	18
Purchased capacity costs	8
Wholesale transmission revenue (net of costs)	(38)
Estimated impact of weather	(30)
Conservation incentive	(18)
Other (net)	18
Total increase in electric margin	$ 137

Natural Gas Margin

Total natural gas expense varies with changing sales requirements and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to natural gas cost recovery mechanisms.

Natural gas revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017	2016
Natural gas revenues before TCJA impact	$ 1,778	$ 1,650	$ 1,531
Cost of natural gas sold and transported	(843)	(823)	(733)
Natural gas margin before TCJA impact	$ 935	$ 827	$ 798
TCJA impact (offset as a reduction in income tax)	(39)	—	—
Natural gas margin	$ 896	$ 827	$ 798

Natural Gas Margin

(Millions of Dollars)	2018 vs. 2017
Retail rate increase (Colorado, Wisconsin and Michigan)	$ 58
Estimated impact of weather	24
Infrastructure and integrity riders	13
Sales growth	6
Conservation revenue (offset by expenses)	3
Other (net)	4
Total increase in natural gas margin before TCJA impact	$ 108
TCJA impact (offset as a reduction in income tax)	(39)
Total increase in natural gas margin	$ 69

(Millions of Dollars)	2017 vs. 2016
Infrastructure and integrity riders	$ 18
Retail sales growth, excluding weather impact	7
Estimated impact of weather	1
Other (net)	3
Total increase in natural gas margin	$ 29

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $82 million, or 3.6%, for 2018. Significant changes are summarized below:

(Millions of Dollars)	2018 vs. 2017
Business systems and contract labor	$ 39
Distribution costs	19
Natural gas systems damage prevention and other remediation	12
Generation plant costs (including increased wind O&M)	11
Nuclear plant operations and amortization	(9)
Other (net)	10
Total increase in O&M expenses	$ 82

- Business systems and contract labor costs increased due to growing network and storage needs, cybersecurity, initiatives to support our customer strategy, and initiatives to improve business processes;
- Distribution costs reflect higher maintenance expenses, including vegetation management; and,
- Nuclear plant operations and amortization are lower largely reflecting savings initiatives and reduced refueling outage costs.

O&M expenses decreased $23 million, or 1.0%, for 2017. Significant changes are summarized as follows:

(Millions of Dollars)	2017 vs. 2016
Nuclear plant operations and amortization	$ (27)
Plant generation costs	(23)
Transmission costs	(2)
Employee benefits expense	17
Texas 2016 electric rate case cost deferral	16
Electric distribution costs	2
Other (net)	(6)
Total decrease in O&M expenses	$ (23)

- Nuclear plant operations and amortization expenses are lower mostly due to reduced refueling outage costs and operating efficiencies.
- Plant generation costs decreased as a result of lower expenses associated with planned outages and overhauls at a number of generation facilities.
- Employee benefits expense includes the recognition of an $8 million pension settlement expense in the fourth quarter of 2017.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $17 million, or 6.2%, for 2018. The increase was primarily due to recovery for conservation programs to assist customers in reducing energy use. Conservation and DSM expenses are generally recovered concurrently through riders and base rates. Timing of recovery may vary from when costs are incurred.

Conservation and DSM program expenses increased $28 million, or 11.4%, for 2017 compared with 2016. The increase was due to higher customer participation in electric conservation programs and recovery rates, mostly in Minnesota.

Depreciation and Amortization — Depreciation and amortization increased $163 million, or 11%, for 2018. The increase was primarily driven by capital investments and additional amortization of a prepaid pension asset in Colorado (approximately $75 million) related to TCJA settlements, which were offset by lower income taxes.

Depreciation and amortization increased $176 million, or 13.5%, for 2017 compared with 2016. The increase was primarily due to capital investments and prior year amortization of the excess depreciation reserve in Minnesota.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $11 million, or 2.0%, for 2018. The increase was primarily due to higher property taxes.

Taxes (other than income taxes) increased $13 million, or 2.4%, for 2017 compared with 2016. The increase was primarily due to higher property taxes in Minnesota and Texas.

AFUDC, Equity and Debt — AFUDC increased $46 million for 2018. The increase was primarily due to the Rush Creek and Hale wind projects and other capital investments.

AFUDC increased $23 million for 2017 compared with 2016. The increase was primarily due to higher CWIP, particularly the Rush Creek wind project.

Interest Charges — Interest expense increased $37 million, or 5.6%, for 2018. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Interest charges increased $16 million, or 2.5%, for 2017 compared with 2016. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $361 million for 2018. The decrease was primarily driven by a lower federal tax rate due to the TCJA, lower pretax earnings, a one time, non-cash income tax expense related to the TCJA in 2017, an increase in plant-related regulatory differences related to ARAM (net of deferrals), 2018 non-plant excess accumulated deferred income tax amortization, and the impact of 2018 investment tax credits. These were partially offset by a higher tax benefit for the resolution of past appeals/audits in 2017 and a higher tax benefit for adjustments in 2017. The ETR was 12.6% for 2018 compared with 32.1% for 2017. The lower ETR in 2018 was largely due to the adjustments above.

Income tax expense decreased $39 million for 2017 compared with 2016. The decrease was primarily driven by increased wind PTCs, a net tax benefit related to the resolution of appeals/audits in 2017, an increase in R&E credits, lower pretax earnings in 2017 and a rise in permanent plant-related adjustments. PTCs are flowed back to customers and reduce electric margin. The decrease was partially offset by the estimated one-time, non-cash, income tax expense recognized in the fourth quarter related to the TCJA. The ETR was 32.1% for 2017 compared with 34.1% for 2016. The lower ETR in 2017 was primarily due to the adjustments referenced above. Excluding the impact for the TCJA adjustment, the ETR would have been 30.7% for 2017.

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

Xcel Energy Inc. and Other Results

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

	Contribution (Millions of Dollars)		
	2018	2017	2016
Xcel Energy Inc. financing costs	$ (110)	$ (79)	$ (71)
Eloigne [(a)]	—	2	1
Xcel Energy Inc. taxes and other results	(5)	(35)	(6)
Total Xcel Energy Inc. and other costs	$ (115)	$ (112)	$ (76)

	Contribution (Diluted Earnings (Loss) Per Share)		
	2018	2017	2016
Xcel Energy Inc. financing costs	$ (0.21)	$ (0.15)	$ (0.14)
Eloigne [(a)]	—	—	—
Xcel Energy Inc. taxes and other results	(0.01)	(0.07)	(0.01)
Total Xcel Energy Inc. and other costs	$ (0.22)	$ (0.22)	$ (0.15)

(a) Amounts include gains or losses associated with sales of properties held by Eloigne.

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

Factors Affecting Results of Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. Historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including those listed below.

Regulation

FERC and State Regulation — The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and WGI. The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries and WGI are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy Inc.'s utility subsidiaries request changes in rates for utility services through filings with governing commissions. Changes in operating costs can affect Xcel Energy's 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 Xcel Energy's results of operations.

Tax Reform — Regulatory Proceedings

In December 2017, the TCJA was signed into law, enacting significant changes to the IRC, including a reduction of the corporate income tax rate from 35% to 21% and a resulting reduction in deferred tax assets and liabilities. As a result of IRS requirements and past regulatory treatment of income taxes in the determination of regulated rates, the impacts of TCJA are primarily recognized as a regulatory liability. Treatment of these tax benefits, (e.g., degree to which benefits will be used to refund currently effective rates and/or used to mitigate other costs and potential future rate increases) is subject to regulatory approval.

Concluded and ongoing regulatory TCJA proceedings:

Operating Company	Utility Service	Approval Date	Additional Information
NSP-Minnesota	Electric and Natural Gas	August 2018	***Minnesota*** — In 2018, the MPUC ordered NSP-Minnesota to refund the 2018 impacts of TCJA, including $135 million to electric customers and low income program funding, and $6 million to natural gas customers.
NSP-Minnesota	Electric	July 2018	***South Dakota*** — In July 2018, the SDPUC approved a settlement providing a one-time customer refund of $11 million for the 2018 impact of the TCJA, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.
NSP-Minnesota	Natural Gas	November 2018	***North Dakota*** — In November 2018, the NDPSC approved a TCJA settlement in which NSP-Minnesota will amortize $1 million annually of the regulatory asset for the remediation of the MGP site in Fargo, ND and retain the TCJA savings to offset the MGP amortization expense.
NSP-Minnesota	Electric	February 2019	***North Dakota*** — In February 2019, the NDPSC approved a settlement including a one-time customer refund of $10 million for 2018, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.
NSP-Wisconsin	Electric and Natural Gas	May 2018	**Wisconsin** — In May 2018, the PSCW approved customer refunds of $27 million and deferrals of approximately $5 million until NSP-Wisconsin's next rate case proceeding.
NSP-Wisconsin	Electric and Natural Gas	May 2018	***Michigan*** — In May 2018, the MPSC approved electric and natural gas TCJA settlement agreements. Most of the electric TCJA benefits were reflected in NSP-Wisconsin's approved Michigan 2018 electric base rate case.
PSCo	Natural Gas	December 2018	In February 2018, the ALJ recommended approval of a TCJA settlement agreement, which included a $20 million reduction to PSCo's provisional rates effective March 1, 2018. In September 2018, PSCo revised its 2018 TCJA benefit estimate to $24 million and requested an equity ratio of 56% to offset the negative impact of the TCJA on credit metrics. In December 2018, the CPUC approved an equity ratio of 54.6% and utilized the remainder of the TCJA benefit to reduce an existing prepaid pension asset. The CPUC also ordered 2018 excess non-plant ADIT benefits of $11.1 million be utilized to accelerate amortization of the prepaid pension asset.
PSCo	Electric	June 2018 October 2018	In 2018, the CPUC approved a TCJA settlement agreement that included a customer refund of $42 million in 2018, with the remainder of the $59 million of TCJA benefits to be used to accelerate the amortization of an existing prepaid pension asset. For 2019, the expected customer refund is estimated to be $67 million, and amortization of the prepaid pension asset is estimated to be $34 million. Impacts of the TCJA for 2020 and future years are expected to be addressed in a future electric rate case.
SPS	Electric	December 2018	***Texas*** - In December 2018, the PUCT approved a rate settlement which fully reflects the TCJA cost impacts and results in no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be up to a 57% equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings.
SPS	Electric	Pending	***New Mexico*** - In September 2018, the NMPRC issued its final order in SPS' 2017 electric rate case, which included a $10 million refund of the 2018 impact of the TCJA. SPS subsequently filed an appeal with the NMSC, including the order to refund retroactive TCJA savings. The NMSC granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs. On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 and eliminate the retroactive TCJA refund. The revised order would be subject to further administrative or judicial review.

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

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					NSP-Minnesota (MPUC)
TCR	Electric	$98	November 2017	Pending	Reflects the revenue requirements for 2018 and a true-up for 2017 and is based on a proposed ROE of 10%. The MPUC decision is expected during the first quarter of 2019.
CIP Incentive	Electric & Natural Gas	$34	March 2018	Received	The MPUC approved 2017 CIP electric and natural gas financial incentives, effective October 2018, of $30 million and $4 million, respectively.
CIP Rider	Electric & Natural Gas	$57	March 2018	Received	The MPUC approved the forecasted 2018 electric and natural gas CIP riders with estimated 2019 recovery of $48 million and $9 million of electric and natural gas CIP expenses, respectively.
2018 GUIC	Natural Gas	$23	November 2017	Pending	Proposed ROE of 10%. The MPUC decision is expected during the first quarter of 2019.
2019 GUIC	Natural Gas	$29	November 2018	Pending	Proposed ROE of 10.25%. Timing of the MPUC decision is uncertain.
RDF	Electric	$42	October 2018	Received	The MPUC approved the 2019 RDF rate based on a net revenue requirement of $42 million, effective January 2019.
RES	Electric	$23	November 2017	Pending	Reflects the revenue requirements for 2018, 2017 true-up and a proposed ROE of 10%. The MPUC decision is expected in the first quarter of 2019.
					PSCo (CPUC)
Multi-Year Rate Case	Natural Gas	$139	June 2017	Received	Proposed annual revenue request of $139 million over three years, $63 million for 2018. Requested an ROE of 10.0% and an equity ratio of 55.25%. In August 2018, CPUC approved an increase of $46 million (prior to TCJA impacts). The interim decision included application of a 2016 HTY, a 13-month average rate base, an ROE of 9.35%, an equity ratio of 54.6% and provided no return on the prepaid pension asset. In December 2018, the CPUC issued the final ruling which upheld the interim decision and finalized the TCJA impacts.
					In October 2018, the CPUC approved a settlement to extend the PSIA rider through 2021.
DSM Incentive	Electric & Natural Gas	$11	April 2018	Received	PSCo earned an electric and natural gas DSM incentive of $9 million and $2 million, respectively, for achieving its 2017 savings goals.
					SPS (PUCT)
Rate Case	Electric	$54	August 2017	Received	In 2017, SPS filed a retail electric, non-fuel base rate increase case in Texas, which included an ROE of 9.5%. In December 2018, PUCT issued a final order approving a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt. In November 2018, SPS filed an application with the PUCT requesting permission to recover $5.4 million in unbilled TCRF revenue from January 23, 2018 through June 9, 2018. Timing of a final order on this matter is uncertain.
					SPS (NMPRC)
Rate Case	Electric	$41	November 2016	Pending	In 2017, SPS filed a notice of appeal to the New Mexico Supreme Court. A decision is not expected until the second half of 2019.
					In September 2018, the NMPRC approved a revenue increase of approximately $8 million, effective Sept. 27, 2018, based on a ROE of 9.1% and a 51% equity ratio. The NMPRC also ordered a refund of $10 million associated with the TCJA impacts (retroactive Jan. 1, 2018 - Sept. 27, 2018). SPS recorded a regulatory liability for this amount in the third quarter of 2018. SPS subsequently filed an appeal of the order. The NMSC subsequently granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs.
Rate Case	Electric	$43	October 2017	Received/ Pending	On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 with the following: eliminating the retroactive refund associated with the TCJA, approving a ROE of 9.56% and approving an equity ratio of 53.97%. Annual revenue increase based on terms of the settlement agreement would be $12.5 million ($8 million from original order plus $4.5 million for changes in ROE and equity ratio). New rates would be effective as of the date provided by the revised NMPRC order (not retrospective to Sept. 26, 2018), which is expected in the second quarter of 2019. The revised order would be subject to further administrative or judicial review.

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

NSP-Minnesota — Mankato Energy Center Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company to purchase the 760 MW natural gas combined cycle Mankato Energy Center for approximately $650 million. NSP-Minnesota previously contracted to purchase the energy and capacity of this facility through a PPA. The asset acquisition is anticipated to close in mid-2019 and subject to regulatory approvals from the MPUC, NDPSC, FERC and DOJ. The acquisition is projected to provide net customer savings of approximately $50 million to $150 million over the life of the plant.

NSP-Minnesota — Wind Repowering Acquisition — In December 2018, NSP-Minnesota filed with the MPUC to acquire the Jeffers and Community Wind North wind farms from Longroad Energy. The wind farms will have approximately 70 MW of capacity after being repowered. The repowering is expected to be completed by December 2020 to qualify for the 100% PTC benefit. The acquisition is projected to provide customer savings of approximately $7 million over the life of the wind farms. Cost of acquisition is approximately $135 million and pending MPUC approval.

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material impact to its 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.

Fuel Supply and Costs

See Item 1 — Fuel Supply and Costs for discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Key assumptions in these valuations include discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which include changes in interest rates and market returns. Changes in the related net pension and postretirement benefits costs and funding requirements may occur in the future due to changes in assumptions. The payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving Xcel Energy would trigger settlement accounting and could require Xcel Energy to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid. For further discussion and a sensitivity analysis on these assumptions, see "Employee Benefits" under Critical Accounting Policies and Estimates.

Environmental Matters

Environmental costs include accruals 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 and spent nuclear fuel disposal expenses, environmental monitoring and disposal of hazardous materials and waste were approximately:

- $309 million in 2018;
- $303 million in 2017; and,
- $304 million in 2016.

Xcel Energy estimates an average annual expense of approximately $356 million from 2019 - 2023 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 at regulated facilities were approximately:

- $50 million in 2018;
- $61 million in 2017; and,
- $93 million in 2016.

See Item 7 — Capital Requirements for further discussion.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and disclosures in compliance with GAAP 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 and disclosures, 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 Inc. 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. Xcel Energy's 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 Xcel Energy assesses 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 Xcel Energy's results of operations, financial condition or cash flows.

As of Dec. 31, 2018 and 2017, Xcel Energy has recorded regulatory assets of $3.8 billion and $3.4 billion, respectively, and regulatory liabilities of $5.6 billion and $5.3 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. In assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets.

See Note 4 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. The tax accrual estimates being 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

Xcel Energy sponsors 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 a number of key assumptions (e.g., annual return level on pension and postretirement health care investment assets, discount rates, mortality rates and health care cost trend rates). In addition, the pension cost calculation uses an asset-smoothing methodology to reduce the volatility of investment performance over time. Pension assumptions are continually reviewed by Xcel Energy..

At Dec. 31, 2018, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87%, which is consistent with the rate set at Dec. 31, 2017. The rate of return used to measure postretirement health care costs is 5.30% at Dec. 31, 2018, which represents a 50 basis point decrease from Dec. 31, 2017. 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 having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 4.31% and postretirement health care obligations at 4.32% at Dec. 31, 2018. This represents a 68 basis point and 70 basis point increase, respectively, from Dec. 31, 2017. 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 at Dec. 31, 2018, a 1% change would result in the following impact on 2018 pension costs:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (17)	$ 17
Discount rate [(a)]	(6)	7

(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 as part of the process 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, 2018 the initial medical trend cost claim assumptions for Pre-65 was 6.5% and Post-65 was 5.3%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. The period from initial trend rate until the ultimate rate is reached is four years. 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.

A 1% change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

	APBO		Service and Interest Components	
(Millions of Dollars)	**+1%**	**-1%**	**+1%**	**-1%**
Health care cost trend	$ 49	$ (42)	$ 3	$ (2)

Funding requirements in 2019 are expected to remain consistent with 2018, continue at that level in 2020 and begin to decline in the following years. While investment returns were below the assumed levels in 2016 and exceeded assumed levels in 2017, investment returns were below the assumed levels in 2018.

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 2018).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $114 million in 2019 and $107 million in 2020, while the actual pension costs were $140 million in 2018 and $139 million in 2017. The expected decrease in 2019 and future year costs is primarily due the settlement charge experienced in 2018 and reductions in loss amortizations.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2016 - 2019:

- $150 million in January 2019;
- $150 million in 2018;
- $162 million in 2017; and,
- $125 million in 2016

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 $11 million, $20 million and $18 million during 2018, 2017 and 2016, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $11 million during 2019.

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 2018, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2018 pension settlement accounting expense.
- 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 expense consistent with accounting guidance. 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.

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 $1.968 billion in 2018 and $1.874 billion in 2017.

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 most recent triennial filing was approved by the MPUC in January 2019 and resulted in no change to the accrual. The 2020 accrual will be set subsequent to a compliance filing that is expected to be submitted in July 2019.

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, which assumes prompt removal and dismantlement. The use of the DECON method is required by the MPUC. 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 3.4% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on the 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 4% 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, 2018.

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

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries 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.

See Note 10 to the consolidated financial statements for further information.

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 Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to certain 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 — Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their 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. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

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's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

At Dec. 31, 2018, fair values by source for net commodity trading contract assets were as follows:

(Millions of Dollars)	Source of Fair Value	Futures / Forwards Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures / Forwards Fair Value
NSP-Minnesota .	2	$ 3	$ 5	$ 2	$ 1	$ 11
PSCo	2	1	—	—	—	1
		$ 4	$ 5	$ 2	$ 1	$ 12

(Millions of Dollars)	Source of Fair Value	Options Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota .	2	$ —	$ 4	$ 1	$ —	$ 5

2 — 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 were as follows:

(Millions of Dollars)	2018	2017
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 16	$ 10
Contracts realized or settled during the period	(10)	(5)
Commodity trading contract additions and changes during the period . . .	11	11
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 17	$ 16

At Dec. 31, 2018, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately $16 million, whereas a 10% decrease would decrease pretax income by approximately $16 million. At Dec. 31, 2017, a 10% increase or decrease in market prices for commodity trading contracts would have an immaterial impact.

Xcel Energy Inc.'s utility subsidiaries' wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations using VaR. VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2018.	$ 4.83	$ 6.00	$ 0.62	$ 5.63	$ 0.06
2017.	0.18	3.00	0.21	0.66	0.04

In November 2018, management temporarily increased the VaR limit to accommodate a 10-year transaction. NSP-Minnesota has been systematically hedging the transaction and the consolidated VaR returned below $3 million in January 2019.

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 24% of its 2019 and approximately 54% of its 2020 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 32% of its average enriched nuclear material requirements from these sources. Alternate potential sources provide the flexibility to manage NSP-Minnesota's nuclear fuel supply. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

Disruptions in third party nuclear fuel supply contracts due to bankruptcies or change of contract assignments have not materially impacted NSP-Minnesota's operational or financial performance.

Interest Rate Risk — Xcel Energy is subject to interest rate risk. Xcel Energy's 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 annual pretax interest expense by approximately $10 million in 2018 and $9 million in 2017.

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. See Note 10 to the consolidated financial statements for further information.

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

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

Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $14 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $3 million. At Dec. 31, 2017, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $26 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $7 million.

Xcel Energy Inc. and its subsidiaries conduct credit reviews for all counterparties and employ 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 Xcel Energy's 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-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.

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

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. 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, 2018.

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, 2018.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2018	2017	2016
Net cash provided by operating activities . . .	$ 3,122	$ 3,126	$ 3,052

Net cash provided by operating activities decreased by $4 million for 2018 as compared to 2017. Change was primarily due to refunds associated with the TCJA and timing of certain electric and natural gas recovery mechanisms, partially offset by the change in net income (excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expenses)).

Net cash provided by operating activities increased by $74 million for 2017 as compared to 2016. Increase was primarily due to higher net income, excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expenses) and timing of customer receipts, partially offset by higher interest payments and pension contributions, refunds, timing of vendor payments and lower income tax refunds.

(Millions of Dollars)	2018	2017	2016
Net cash used in investing activities	$ (3,986)	$ (3,296)	$ (3,261)

Net cash used in investing activities increased by $690 million for 2018 as compared to 2017. Increase was largely related to higher capital expenditures for the Rush Creek, Foxtail and Hale wind generation facilities.

Net cash used in investing activities increased by $35 million for 2017 as compared to 2016. Increase was mainly attributable to capital expenditures related to the Rush Creek wind generation facility, partially offset by amounts for the Courtenay wind farm and less rabbi trust investments.

(Millions of Dollars)	2018	2017	2016
Net cash provided by financing activities. . . .	$ 928	$ 168	$ 209

Net cash provided by financing activities increased by $760 million for 2018 as compared to 2017. Increase was primarily due to lower repayments of long-term debt, proceeds from the issuances of common stock and additional debt financings, partially offset by lower short-term debt proceeds as compared to 2017.

Net cash provided by financing activities decreased by $41 million for 2017 as compared to 2016. Decrease was primarily due to lower proceeds from debt issuances and higher dividend payments, partially offset by higher short-term debt proceeds and lower repurchases of common stock in 2017.

Capital Requirements

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.

Contractual Obligations and Other Commitments — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. Contractual obligations and other commercial commitments as of Dec. 31, 2018 were as follows:

		Payments Due by Period			
(Millions of Dollars)	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	After 5 Years
Long-term debt, principal and interest payments	$ 27,538	$ 1,062	$ 2,910	$ 2,711	$ 20,855
Capital lease obligations	286	14	28	24	220
Operating leases [(a)]	2,174	239	469	429	1,037
Unconditional purchase obligations [(b)]	6,700	1,457	1,990	1,432	1,821
Other long-term obligations, including current portion	716	57	98	64	497
Other short-term obligations	405	405	—	—	—
Short-term debt	1,038	1,038	—	—	—
Total contractual cash obligations	$ 38,857	$ 4,272	$ 5,495	$ 4,660	$ 24,430

(a) Included in operating lease payments are $207 million, $418 million, $383 million and $0.9 billion, 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 coal, nuclear fuel and natural gas 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.

See Notes 5 and 12 to the consolidated financial statements for further information.

Capital Expenditures — Current estimated base capital expenditure programs of Xcel Energy's operating companies for the years 2019 - 2023:

	Capital Forecast					
(Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
By Subsidiary						
NSP-Minnesota	$ 2,825	$ 1,290	$ 1,540	$ 1,300	$ 1,380	$ 8,335
PSCo	1,370	1,380	1,335	1,395	1,530	7,010
SPS	1,130	770	460	530	635	3,525
NSP-Wisconsin	240	240	300	305	275	1,360
Other [(a)]	(50)	(70)	(25)	10	15	(120)
Total capital expenditures	$ 5,515	$ 3,610	$ 3,610	$ 3,540	$ 3,835	$ 20,110

	Capital Forecast					
(Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
By Function						
Electric distribution	$ 775	$ 865	$ 1,150	$ 1,245	$ 1,270	$ 5,305
Electric transmission	580	560	950	870	1,055	4,015
Renewables	2,315	1,105	240	—	—	3,660
Electric generation	1,070	310	480	560	545	2,965
Natural gas	430	415	420	510	595	2,370
Other [(b)]	345	355	370	355	370	1,795
Total capital expenditures	$ 5,515	$ 3,610	$ 3,610	$ 3,540	$ 3,835	$ 20,110

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

(b) Amounts in other category are net of intercompany transfers.

Xcel Energy's capital expenditure program is subject to continuous review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities.

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.

Financing Capital Expenditures through 2023 — 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 2019 - 2023:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	$ 13,070
New Debt**	6,190
Equity through the DRIP and Benefit Program	390
Equity through forward equity agreements	460
Base Capital Expenditures 2019 - 2023	$ 20,110
Maturing Debt	$ 3,645

* Net of dividends and pension funding.

** Reflects a combination of short and long-term debt; net of refinancing.

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 2019, Xcel Energy announced a quarterly dividend of $0.405 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; and,
- 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 system to declare dividends. Specifically, 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, 2018	Dec. 31, 2017
Fair value of pension assets	$ 2,742	$ 3,088
Projected pension obligation [(a)]	3,477	3,828
Funded status	$ (735)	$ (740)

(a) Excludes non-qualified plan of $33 million and $37 million at Dec. 31, 2018 and 2017, respectively.

Pension Assumptions	2018	2017
Discount rate	4.31%	3.63%
Expected long-term rate of return	6.87	6.87

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating 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 billion for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $400 million for SPS; and,
- $150 million for NSP-Wisconsin.

In addition, Xcel Energy Inc. has a 364-day term loan agreement to borrow up to $500 million. As of Dec. 31, 2018, $250 million of borrowings were outstanding with $250 million additional borrowing capacity. In February 2019, Xcel Energy borrowed the remaining $250 million. No additional borrowing capacity currently remains.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018
Borrowing limit	$ 3,250
Amount outstanding at period end	1,038
Average amount outstanding	500
Maximum amount outstanding	1,038
Weighted average interest rate, computed on a daily basis	2.76%
Weighted average interest rate at end of period	2.97

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Borrowing limit	$ 3,250	$ 3,250	$ 2,750
Amount outstanding at period end	1,038	814	392
Average amount outstanding	788	644	485
Maximum amount outstanding	1,349	1,247	1,183
Weighted average interest rate, computed on a daily basis	2.34%	1.35%	0.74%
Weighted average interest rate at end of period	2.97	1.90	0.95

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 2021 termination date. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Feb. 20, 2019, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility	Drawn [(a)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,500	$ 786	$ 714	$ —	$ 714
PSCo	700	224	476	1	477
NSP-Minnesota	500	152	348	1	349
SPS	400	128	272	—	272
NSP-Wisconsin	150	29	121	1	122
Total	$ 3,250	$ 1,319	$ 1,931	$ 3	$ 1,934

(a) Includes outstanding commercial paper, term loan borrowings 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, 2018 and 2017, Xcel Energy Inc. had approximately 514 million shares and 508 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 Inc. and its utility subsidiaries' 2019 financing plans reflect the following:

- Xcel Energy Inc. — approximately $700 million of senior notes and approximately $75 to $80 million of equity through the DRIP and benefit programs;
- NSP-Minnesota — approximately $900 million of first mortgage bonds;
- PSCo — approximately $800 million of first mortgage bonds; and,
- SPS — approximately $300 million of first mortgage bonds.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward sale agreements in connection with a completed $459 million public offering of 9.4 million shares of Xcel Energy common stock. The initial forward agreement was for 8.1 million shares with an additional forward agreement of 1.2 million shares exercised at the option of the banking counterparty. At Dec. 31, 2018, the forward agreements could have been settled with physical delivery of 9.4 million common shares to the banking counterparty in exchange for cash of $456 million. The forward instruments could also have been settled at Dec. 31, 2018 with delivery of approximately $24 million of cash or approximately 0.5 million shares of common stock to the banking counterparty, if Xcel Energy unilaterally elected net cash or net share settlement, respectively.

The forward price used to determine amounts due at settlement is calculated based on the November 2018 public offering price for Xcel Energy's common stock of $49.00, increased for the overnight bank funding rate, less a spread of 0.75% and less expected dividends on Xcel Energy's common stock during the period the instruments are outstanding.

Xcel Energy may settle the forward agreements at any time up to the maturity date of February 7, 2020. The cash proceeds, depending on the timing of settlement, are expected to be approximately $450 million to $460 million.

Forward equity instruments were accounted for as stockholders' equity and recorded at fair value at the execution of the forward agreements, and will not be subsequently adjusted for changes in fair value until settlement.

ATM Equity Offering — In 2018, Xcel Energy issued 4.7 million shares of common stock with net proceeds of $224.7 million through the at the market program. In addition, total transaction fees of $1.9 million were paid. In November 2018, the ATM offering was closed.

Other Equity — Xcel Energy also plans to issue approximately $75 to $80 million of equity, each year, through the DRIP and benefit programs during the five-year forecast time period.

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

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.

Earnings Guidance

2019 GAAP and ongoing earnings guidance is a range of $2.55 to $2.65 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the year.
- Weather-normalized retail electric sales are projected to be relatively consistent with 2018 levels.
- Weather-normalized retail natural gas sales are projected to be within a range of 0.0% to 1.0% over 2018 levels.
- Capital rider revenue is projected to increase $115 million to $125 million (net of PTCs) over 2018 levels. PTCs are flowed back to customers, primarily through capital riders as reductions to electric margin.
- Purchase capacity costs are expected to decline $25 million to $30 million compared with 2018 levels.
- O&M expenses are projected to be consistent with 2017 levels.
- Depreciation expense is projected to increase approximately $120 million to $130 million over 2018 levels. Depreciation expense includes $34 million for the amortization of a prepaid pension asset at PSCo, which is TCJA related and will not impact earnings.
- Property taxes are projected to increase approximately $15 million to $25 million over 2018 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $90 million to $100 million over 2018 levels.
- AFUDC — equity is projected to decrease approximately $20 million to $30 million from 2018 levels.
- The ETR is projected to be approximately 6% to 8%. The ETR reflects benefits of PTCs which are flowed back to customers through electric margin.
- Assumptions do not include the impact for the upcoming adoption of the new lease accounting standard, effective 2019. Xcel Energy does not expect changes in the accounting for leases to impact earnings, but it may result in variations in certain line items within the statement of 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.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See 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 Controls 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, 2018. 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, 2018, 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 audit report on the Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE	/s/ ROBERT C. FRENZEL
Ben Fowke	Robert C. Frenzel
Chairman, President and Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 22, 2019	Feb. 22, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders 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, 2018 and 2017, 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, 2018, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2019

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		
	2018	2017	2016
Operating revenues			
Electric	$ 9,719	$ 9,676	$ 9,500
Natural gas	1,739	1,650	1,531
Other	79	78	76
Total operating revenues	11,537	11,404	11,107
Operating expenses			
Electric fuel and purchased power	3,854	3,757	3,718
Cost of natural gas sold and transported	843	823	733
Cost of sales — other	35	34	36
Operating and maintenance expenses	2,352	2,270	2,300
Conservation and demand side management program expenses	290	273	245
Depreciation and amortization	1,642	1,479	1,303
Taxes (other than income taxes)	556	545	532
Total operating expenses	9,572	9,181	8,867
Operating income	1,965	2,223	2,240
Other expense, net	(14)	(10)	(18)
Equity earnings of unconsolidated subsidiaries	35	30	42
Allowance for funds used during construction — equity	108	75	60
Interest charges and financing costs			
Interest charges — includes other financing costs of $25, $24 and $25, respectively	700	663	647
Allowance for funds used during construction — debt	(48)	(35)	(27)
Total interest charges and financing costs	652	628	620
Income before income taxes	1,442	1,690	1,704
Income taxes	181	542	581
Net income	$ 1,261	$ 1,148	$ 1,123
Weighted average common shares outstanding:			
Basic	511	509	509
Diluted	511	509	509
Earnings per average common share:			
Basic	$ 2.47	$ 2.26	$ 2.21
Diluted	2.47	2.25	2.21

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2018	2017	2016
Net income	$ 1,261	$ 1,148	$ 1,123
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of $(2), $(2), and $(5), respectively	(6)	(3)	(8)
Amortization of losses included in net periodic benefit cost, net of tax of $3, $5, and $2, respectively	9	7	4
	3	4	(4)
Derivative instruments:			
Net fair value decrease, net of tax of $(2), $0, and $0, respectively	(5)	—	—
Reclassification of losses to net income, net of tax of $1, $2, and $2, respectively	3	3	4
	(2)	3	4
Other comprehensive income	1	7	—
Comprehensive income	$ 1,262	$ 1,155	$ 1,123

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net income	$ 1,261	$ 1,148	$ 1,123
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,659	1,495	1,319
Nuclear fuel amortization	122	114	117
Deferred income taxes	218	640	587
Allowance for equity funds used during construction	(108)	(75)	(60)
Equity earnings of unconsolidated subsidiaries	(35)	(30)	(42)
Dividends from unconsolidated subsidiaries	37	41	46
Provision for bad debts	42	39	39
Share-based compensation expense	45	57	41
Net realized and unrealized hedging and derivative transactions	22	2	8
Changes in operating assets and liabilities:			
Accounts receivable	(105)	(60)	(83)
Accrued unbilled revenues	9	(34)	(75)
Inventories	(65)	(3)	1
Other current assets	18	9	61
Accounts payable	90	43	118
Net regulatory assets and liabilities	223	(16)	(19)
Other current liabilities	(61)	(38)	20
Pension and other employee benefit obligations	(179)	(133)	(91)
Other, net	(71)	(73)	(58)
Net cash provided by operating activities	3,122	3,126	3,052
Investing activities			
Utility capital/construction expenditures	(3,957)	(3,244)	(3,195)
Purchases of investment securities	(853)	(1,697)	(547)
Proceeds from the sale of investment securities	833	1,669	479
Other, net	(9)	(24)	2
Net cash used in investing activities	(3,986)	(3,296)	(3,261)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	225	422	(454)
Proceeds from issuance of long-term debt	1,675	1,518	2,424
Repayments of long-term debt, including reacquisition premiums	(452)	(1,030)	(1,036)
Proceeds from issuance of common stock	230	—	—
Repurchases of common stock	(1)	(3)	(32)
Dividends paid	(730)	(721)	(681)
Other, net	(19)	(18)	(12)
Net cash provided by financing activities	928	168	209
Net change in cash and cash equivalents	64	(2)	—
Cash and cash equivalents at beginning of period	83	85	85
Cash and cash equivalents at end of period	$ 147	$ 83	$ 85
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (633)	$ (616)	$ (592)
Cash received for income taxes, net	27	44	62
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 388	$ 464	$ 311
Inventory transfers to property, plant and equipment	129	63	107
Allowance for equity funds used during construction	108	75	61
Issuance of common stock for reinvested dividends and equity awards	67	31	29

See Notes to Consolidated Financial Statements

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

	Dec. 31 2018	Dec. 31 2017
Assets		
Current assets		
Cash and cash equivalents	$ 147	$ 83
Accounts receivable, net	860	797
Accrued unbilled revenues	755	764
Inventories	548	610
Regulatory assets	464	424
Derivative instruments	87	44
Prepaid taxes	79	68
Prepayments and other	154	183
Total current assets	3,094	2,973
Property, plant and equipment, net	36,944	34,329
Other assets		
Nuclear decommissioning fund and other investments	2,317	2,397
Regulatory assets	3,326	3,005
Derivative instruments	34	48
Deposits and other	272	278
Total other assets	5,949	5,728
Total assets	$ 45,987	$ 43,030
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 406	$ 457
Short-term debt	1,038	814
Accounts payable	1,237	1,243
Regulatory liabilities	436	239
Taxes accrued	450	448
Accrued interest	174	174
Dividends payable	195	183
Derivative instruments	61	29
Other	463	501
Total current liabilities	4,460	4,088
Deferred credits and other liabilities		
Deferred income taxes	4,165	3,845
Deferred investment tax credits	54	58
Regulatory liabilities	5,187	5,083
Asset retirement obligations	2,568	2,475
Derivative instruments	129	126
Customer advances	199	193
Pension and employee benefit obligations	994	1,042
Other	206	145
Total deferred credits and other liabilities	13,502	12,967
Commitments and contingencies		
Capitalization		
Long-term debt	15,803	14,520
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 514,036,787 and 507,762,881 shares outstanding at Dec. 31, 2018 and 2017, respectively	1,285	1,269
Additional paid in capital	6,168	5,898
Retained earnings	4,893	4,413
Accumulated other comprehensive loss	(124)	(125)
Total common stockholders' equity	12,222	11,455
Total liabilities and equity	$ 45,987	$ 43,030

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(amounts in millions, shares in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2015	507,536	$ 1,269	$ 5,889	$ 3,553	$ (110)	$ 10,601
Net income				1,123		1,123
Dividends declared on common stock ($1.36 per share)				(694)		(694)
Issuances of common stock	486	1	15			16
Repurchases of common stock	(799)	(2)	(30)			(32)
Share-based compensation			7			7
Balance at Dec. 31, 2016	507,223	$ 1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				1,148		1,148
Other comprehensive income					7	7
Dividends declared on common stock ($1.44 per share)				(736)		(736)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			16	(3)		13
Adoption of ASU No. 2018-02				22	(22)	—
Balance at Dec. 31, 2017	507,763	$ 1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				1,261		1,261
Other comprehensive income					1	1
Dividends declared on common stock ($1.52 per share)				(780)		(780)
Issuances of common stock	6,296	16	254			270
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			17	(1)		16
Balance at Dec. 31, 2018	514,037	$ 1,285	$ 6,168	$ 4,893	$ (124)	$ 12,222

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 and Capital Services. 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. 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, Nicollet Project 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 investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries.

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. See Note 3 for further information.

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.

Xcel Energy has evaluated events occurring after Dec. 31, 2018 up to the date of issuance of these consolidated financial statements. 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 on 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 or cash flows.

See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires 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 the tax 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 will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

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.

Xcel Energy reports interest and penalties related to income taxes within the other income and 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 — 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 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. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.1% for 2018, 3.1% for 2017 and 2.9% for 2016.

See Note 3 for further information.

AROs — Xcel Energy Inc.'s utility subsidiaries account 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. Xcel Energy Inc.'s utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

See Note 12 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

For ratemaking purposes, NSP-Minnesota recovers the decommissioning costs of its nuclear power plants over each facility's expected service life 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 Note 10 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. If an environmental expense is related to facilities currently in use, such as 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 PRPs 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 on a systematic basis 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.

Xcel Energy's utility subsidiaries recognize sales to customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other RTO revenues and charges 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, 2018 and 2017, the allowance for bad debts was $55 million and $52 million, respectively.

Inventory — Inventory is recorded at average cost and consisted of the following:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$ 271	$ 311
Fuel	170	186
Natural gas	107	113
	$ 548	$ 610

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, vehicle fuel 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; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and O&M costs; 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 and CIP/DSM programs) qualify as alternative revenue programs under GAAP. 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. When certain criteria are met, such as 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 when 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 plus 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 refueling outage 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 costs for the cost of RECs and records that cost as a regulatory asset when the amount is 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.

2. Accounting Pronouncements

Recently Issued

Leases — In 2016, the FASB issued *Leases, Topic 842 (ASU No. 2016-02)*, which requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. Adoption will occur on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions of whether agreements existing before the adoption date contain leases, and whether existing leases are operating or capital/finance leases. Xcel Energy expects to utilize other expedients offered by the new standard and *Leases, Topic 842 (ASU No. 2018-11)*, including elections to not recognize short term leases on the consolidated balance sheet for certain classes of assets and to implement the standard on a prospective basis. Xcel Energy's implementation of the new guidance is substantially complete, and is expected to result in the recognition of approximately $2 billion of right-of-use assets and lease liabilities in the first quarter of 2019 for operating leases for the use of real estate, equipment and certain natural gas generating facilities operated under PPAs. The implementation is not expected to have a significant impact on Xcel Energy's consolidated financial statements, other than first-time recognition of these operating leases on the consolidated balance sheet.

Recently Adopted

Revenue Recognition — In 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. Xcel Energy implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The implementation did not have a material impact on Xcel Energy's consolidated financial statements, other than increased disclosures regarding revenues related to contracts with customers.

Classification and Measurement of Financial Instruments — In 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Xcel Energy implemented the guidance on Jan. 1, 2018 and the adoption impacts were not material.

Presentation of Net Periodic Benefit Cost — In 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost portion of pension cost may be presented as a component of operating income. In addition, only the service cost portion of pension cost is eligible for capitalization. As a result of regulatory accounting treatment, a similar amount of pension cost, including non-service components, will be recognized consistent with historical ratemaking and the impacts of adoption are limited to changes in classification of non-service costs in the consolidated statements of income.

Xcel Energy implemented the new guidance on Jan. 1, 2018. As a result, $33 million and $26 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other expense, net on the consolidated statements of income for 2017 and 2016, respectively. Xcel Energy used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Property, Plant and Equipment

Major classes of property, plant and equipment:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Property, plant and equipment		
Electric plant	$ 41,472	$ 39,016
Natural gas plant	6,210	5,800
Common and other property	2,154	2,013
Plant to be retired [(a)]	322	11
CWIP	2,091	2,087
Total property, plant and equipment	52,249	48,927
Less accumulated depreciation	(15,659)	(15,000)
Nuclear fuel	2,771	2,697
Less accumulated amortization	(2,417)	(2,295)
	$ 36,944	$ 34,329

(a) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in approximately 2022 and 2025, respectively. PSCo also expects Craig Unit 1 to be retired early in 2025. Amounts are presented net of accumulated depreciation.

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2018:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Minnesota				
Electric Generation:				
Sherco Unit 3	$ 604	$ 415	$ 1	59%
Sherco Common Facilities	145	100	1	80
Other	5	4	—	59
Electric Transmission:				
CapX2020 Transmission	960	73	2	51
Other	11	2	—	50
Total NSP-Minnesota	$ 1,725	$ 594	$ 4	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Wisconsin				
Electric Transmission:				
La Crosse, WI to Madison, WI	$ 175	$ 2	$ —	37%
CapX2020 Transmission	169	15	2	81
Total NSP-Wisconsin	$ 344	$ 17	$ 2	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
PSCo				
Electric Generation:				
Hayden Unit 1	$ 153	$ 76	$ —	76%
Hayden Unit 2	149	68	—	37
Hayden Common Facilities	41	21	—	53
Craig Units 1 and 2	81	40	—	10
Craig Common Facilities	39	21	—	7
Comanche Unit 3	886	130	—	67
Comanche Common Facilities	28	3	—	82
Electric Transmission:				
Transmission and other facilities	183	63	1	Various
Gas Transportation:				
Rifle, CO to Avon, CO	22	7	—	60
Gas Transportation Compressor	8	1	—	50
Total PSCo	$ 1,590	$ 430	$ 1	

Each company's share of operating expenses and construction expenditures are 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, 2018		Dec. 31, 2017	
Regulatory Assets			Current	Non- current	Current	Non- current
Pension and retiree medical obligations	11	Various	$ 87	$ 1,500	$ 91	$ 1,499
Net AROs [(a)]	1, 12	Plant lives	—	452	—	301
Excess deferred taxes - TCJA	7	Various	—	296	—	254
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	264	—	244
Environmental remediation costs	1, 12	Various	17	155	16	165
Depreciation differences		One to thirteen years	18	107	20	69
Benson biomass PPA termination and asset purchase		Ten years	10	86	—	—
Contract valuation adjustments [(b)]	1, 10	Term of related contract	17	77	21	93
Laurentian biomass PPA termination		Five years	18	73	—	—
Purchased power contract costs		Term of related contract	4	63	3	67
PI EPU		Sixteen years	3	56	3	58
Losses on reacquired debt		Term of related debt	4	44	5	48
State commission adjustments		Plant lives	1	29	1	29
Conservation programs [(c)]	1	One to two years	42	28	50	32
Property tax		Various	14	10	8	24
Nuclear refueling outage costs	1	One to two years	37	14	49	20
Deferred purchased natural gas and electric energy costs		One to three years	57	13	21	13
Renewable resources and environmental initiatives		One to two years	39	9	48	10
Sales true up and revenue decoupling		One to two years	38	7	37	12
Gas pipeline inspection and remediation costs		One to two years	28	3	24	12
Other		Various	30	40	27	55
Total regulatory assets			$ 464	$ 3,326	$ 424	$ 3,005

(a) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(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 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, 2018		Dec. 31, 2017	
Regulatory Liabilities			Current	Non- current	Current	Non- current
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 157	$ 3,715	$ —	$ 3,790
Plant removal costs	1, 12	Plant lives	—	1,175	—	1,131
Effects of regulation on employee benefit costs [(b)]		Various	—	137	—	46
Renewable resources and environmental initiatives		Various	9	54	19	60
ITC deferrals [(c)]	1	Various	—	40	—	23
Deferred electric, natural gas and steam production costs		Less than one year	102	—	104	—
Contract valuation adjustments [(d)]	1, 10	Less than one year	26	—	30	—
Conservation programs [(e)]	1	Less than one year	36	—	23	—
DOE settlement		Less than one year	19	—	18	—
Other		Various	87	66	45	33
Total regulatory liabilities [(f)]			$ 436	$ 5,187	$ 239	$ 5,083

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes regulatory amortization and certain TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset at Dec. 31, 2018.

(c) Includes impact of lower federal tax rate due to the TCJA.

(d) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(e) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(f) Revenue subject to refund of $29 million and $15 million for 2018 and 2017, respectively, is included in other current liabilities.

At Dec. 31, 2018 and 2017, Xcel Energy's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations, net AROs and Laurentian biomass PPA termination costs/obligations. In addition, regulatory assets included $178 million and $212 million at Dec. 31, 2018 and 2017, respectively, of past expenditures not earning a return. Amounts largely related to purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Short-Term Debt — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper, term loan borrowings and letters of credit under their credit facilities.

Short-term debt borrowings outstanding for Xcel Energy were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018	Year Ended Dec. 31 2018	Year Ended Dec. 31 2017	Year Ended Dec. 31 2016
Borrowing limit	$ 3,250	$ 3,250	$ 3,250	$ 2,750
Amount outstanding at period end	1,038	1,038	814	392
Average amount outstanding	500	788	644	485
Maximum amount outstanding	1,038	1,349	1,247	1,183
Weighted average interest rate, computed on a daily basis	2.76%	2.34%	1.35%	0.74%
Weighted average interest rate at end of period	2.97	2.97	1.90	0.95

Term Loan Agreement — In December 2018, Xcel Energy Inc. renewed its $500 million 364-Day Term Loan Agreement with $250 million outstanding. In February 2019, Xcel Energy borrowed the remaining amount. No additional capacity remains as loans borrowed and repaid may not be redrawn. The loan is unsecured and matures Dec. 3, 2019. Xcel Energy has an option to request an extension through Dec. 2, 2020. Term loan includes one financial covenant, requiring Xcel Energy's consolidated funded debt to total capitalization ratio to be less than or equal to 65 percent. Interest is at a rate equal to either (i) the Eurodollar rate, plus 50.0 basis points, or (ii) an alternate base rate. Xcel Energy is also required to pay a commitment fee equal to 10 basis points per annum on the unborrowed portion.

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2018 and 2017, there were $49 million and $30 million of letters of credit outstanding. Amounts approximate their fair value.

Credit Facilities — Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their 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.

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio[(a)] 2018	Debt-to-Total Capitalization Ratio[(a)] 2017	Amount Facility May Be Increased (millions)	Additional Periods For Which a One-Year Extension May Be Requested [(b)]
Xcel Energy Inc. [(c)]	58%	58%	$ 200	2
NSP-Wisconsin	48	47	N/A	1
NSP-Minnesota	48	48	100	2
SPS	46	46	50	2
PSCo	46	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. will 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, 2018, 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, 2018:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available
Xcel Energy Inc.	$ 1,500	$ 488	$ 1,012
PSCo	700	317	383
NSP-Minnesota	500	187	313
SPS	400	44	356
NSP-Wisconsin	150	51	99
Total	$ 3,250	$ 1,087	$ 2,163

(a) These credit facilities mature in June 2021, with the exception of Xcel Energy's Inc.'s 364-day term loan agreement which expires in December 2019.

(b) Includes outstanding commercial paper, term loan borrowings and letters of credit.

All credit facility bank borrowings, outstanding letters of credit, term loan borrowings and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2018 and 2017.

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:

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Xcel Energy Inc.					
Unsecured senior notes	2020 - 2041	2.40% - 6.50%	1.20% - 6.50%	$ 3,400	$ 2,900
Elimination of PSCo capital lease obligation with affiliates				(60)	(62)
Unamortized discount				(5)	(2)
Unamortized debt issuance cost				(21)	(20)
Current maturities (Capital lease obligation)				2	2
Total				$ 3,316	$ 2,818

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Minnesota					
Mortgage bonds	2020 - 2047	2.15% - 7.13%	2.15% - 7.13%	$ 5,000	$ 5,000
Unamortized discount				(21)	(22)
Unamortized debt issuance cost				(42)	(45)
Current maturities				—	—
Total				$ 4,937	$ 4,933

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Wisconsin					
Mortgage bonds	2024 - 2048	3.3% - 6.38%	3.3% - 6.38%	$ 800	$ 750
City of La Crosse resource recovery bond	2021	6.00%	6.00%	19	19
Other				—	2
Unamortized discount				(3)	(3)
Unamortized debt issuance cost				(9)	(7)
Current maturities				—	(151)
Total				$ 807	$ 610

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
PSCo					
Capital lease obligations	2025 - 2060	11.20% - 14.30%	11.20% - 14.30%	$ 145	$ 151
Mortgage bonds	2019 - 2048	2.25% - 6.50%	2.25% - 6.50%	4,900	4,500
Unamortized discount				(14)	(13)
Unamortized debt issuance cost				(33)	(29)
Current maturities				(406)	(306)
Total				$ 4,592	$ 4,303

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
SPS					
Mortgage bonds	2024 - 2048	3.30% - 4.50%	3.30% - 4.50%	$ 1,800	$ 1,500
Unsecured senior notes	2033 - 2036	6.00%	6.00% - 8.75%	350	350
Unamortized discount				(4)	(2)
Unamortized debt issuance cost				(20)	(18)
Current maturities				—	—
Total				$ 2,126	$ 1,830

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Other Subsidiaries					
Various Eloigne Co. affordable housing project notes	2019 - 2052	0.00% - 6.90%	0.00% - 7.05%	$ 26	$ 28
Current maturities				(1)	(2)
Total				$ 25	$ 26

Maturities of long-term debt:

(Millions of Dollars)		
2019	$	406
2020		1,257
2021		425
2022		902
2023		653

2018 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
Xcel Energy Inc.	$500 million	Senior Notes	4.00%	June 15, 2028
PSCo	350 million	First mortgage bonds	3.70	June 15, 2028
PSCo	350 million	First mortgage bonds	4.10	June 15, 2048
NSP-Wisconsin	200 million	First mortgage bonds	4.20	Sept. 1, 2048
SPS	300 million	First mortgage bonds	4.40	Nov 15, 2048

2017 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
PSCo	$400 million	First mortgage bonds	3.80%	June 15, 2047
SPS	450 million	First mortgage bonds	3.70	Aug. 15, 2047
NSP-Minnesota	600 million	First mortgage bonds	3.60	Sept. 15, 2047
NSP-Wisconsin	100 million	First mortgage bonds	3.75	Dec. 1, 2047

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward sale agreements in connection with a completed $459 million public offering of 9.4 million shares of Xcel Energy common stock. The initial forward agreement was for 8.1 million shares with an additional agreement of 1.2 million shares exercised at the option of the banking counterparty. At Dec. 31, 2018, the forward agreements could have been settled with physical delivery of 9.4 million common shares to the banking counterparty in exchange for cash of $456 million. The forward instruments could also have been settled at Dec. 31, 2018 with delivery of approximately $24 million of cash or approximately 0.5 million shares of common stock to the counterparty, if Xcel Energy unilaterally elected net cash or net share settlement, respectively. The forward price used to determine amounts due at settlement is calculated based on the November 2018 public offering price for Xcel Energy's common stock of $49.00, increased for the overnight bank funding rate, less a spread of 0.75% and less expected dividends on Xcel Energy's common stock during the period the instruments are outstanding.

Xcel Energy may settle the agreements at any time up to the maturity date of February 7, 2020. Depending on settlement timing, cash proceeds are expected to be approximately $450 million to $460 million.

Forward equity instruments were recognized within stockholders' equity at fair value at execution of the agreements, and will not be subsequently adjusted until settlement.

ATM Equity Offering — Xcel Energy issued 4.7 million shares of common stock with net proceeds of $224.7 million through the at-the-market program. In addition, transaction fees of $1.9 million were paid. In November 2018, the ATM offering was closed.

Other Equity — Xcel Energy issued $38.5 million and $39.2 million of equity through the DRIP program during the years ended Dec. 31, 2018 and 2017 respectively. Program allows stockholders to elect dividend reinvestment in Xcel Energy common stock through a non-cash transaction. See Note 8 for equity items related to share based compensation.

Deferred Financing Costs — Deferred financing costs of approximately $126 million and $119 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2018 and 2017, respectively.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2018 and 2017
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:

Commons Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) 2018	Common Stock Outstanding (Shares) 2017
1 billion	$ 2.50	514,036,787	507,762,881

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its 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.

Requirements and actuals as of Dec. 31, 2018:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2018
NSP-Minnesota	47.1%	57.5%	52.3%
NSP-Wisconsin	51.5	N/A	51.8
SPS (a)	45.0	55.0	54.4

(a) SPS excludes short-term debt.

	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1.0 billion	$ 10.7 billion	$ 11.5 billion
NSP-Wisconsin (a)	11.5 million	1.7 billion	N/A
SPS (b)	605.7 million	4.7 billion	N/A

(a) NSP-Wisconsin cannot pay annual dividends in excess of approximately $55 million if its average equity-to-total capitalization ratio falls below the commission authorized level.

(b) SPS may not pay a dividend that would cause it to lose its investment grade bond rating.

Issuance of securities by Xcel Energy Inc. generally is not 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.

Authorizations as of Dec. 31, 2018:

	Amount Authorized to Issue	
	Long-Term Debt	Short-Term Debt
NSP-Minnesota	52.93% of total capitalization (a)	$ 1.725 billion (a)
NSP-Wisconsin	$ — (b)	150 million
SPS	— (b)	600 million
PSCo	1.1 billion	800 million

(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) SPS and NSP-Wisconsin will file for additional long-term debt authorization.

6. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. Xcel Energy's operating revenues (subsequent to adoption of the revised revenue guidance) consists of the following:

	Year Ended Dec. 31, 2018			
(Millions of Dollars)	**Electric**	**Natural Gas**	**All Other**	**Total**
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,919	$ 988	$ 38	$ 3,945
C&I	4,874	524	25	5,423
Other	134	—	6	140
Total retail	7,927	1,512	69	9,508
Wholesale	791	—	—	791
Transmission	523	—	—	523
Other	98	100	—	198
Total revenue from contracts with customers	9,339	1,612	69	11,020
Alternative revenue and other	380	127	10	517
Total revenues	$ 9,719	$ 1,739	$ 79	$ 11,537

7. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy, generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for NOLs arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Xcel Energy estimated the effects of the TCJA, which have been reflected in the consolidated financial statements.

Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of IRS requirements and past regulatory treatment.

Estimated impacts of the new tax law in December 2017 included:

- $2.7 billion ($3.8 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over an estimated weighted average period of approximately 30 years;
- $254 million and $174 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and,
- $23 million of total estimated income tax expense related to the tax rate change on certain non-plant deferred taxes and all other 2017 income statement impacts of the federal tax reform.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Tax Loss Carryback Claims — In 2012 - 2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

Federal Audit — Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020
2017	September 2021

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2018, the case has been forwarded to the Office of Appeals and 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.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016, however no adjustments have been proposed.

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, 2018, 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	2009
Minnesota	2009
Texas	2010
Wisconsin	2014

- In the fourth quarter of 2018, the Minnesota audit of tax years 2010 - 2014 concluded with no material adjustments.
- In the third quarter of 2018, the Wisconsin audit of tax years 2012 - 2013 concluded with no material adjustments. In the fourth quarter of 2018, Wisconsin began an audit of tax years 2014 - 2016. No material adjustments have been proposed.
- No other state income tax audits were in progress as of Dec. 31, 2018.

Unrecognized Tax Benefits — 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 the 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)	Dec. 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 28	$ 20
Unrecognized tax benefit — Temporary tax positions	9	19
Total unrecognized tax benefit	$ 37	$ 39

Changes in unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 39	$ 134	$ 121
Additions based on tax positions related to the current year	9	6	8
Reductions based on tax positions related to the current year	(4)	(4)	—
Additions for tax positions of prior years	2	15	10
Reductions for tax positions of prior years	(4)	(105)	(5)
Settlements with taxing authorities	(5)	(7)	—
Balance at Dec. 31	$ 37	$ 39	$ 134

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (35)	$ (31)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $24 million and $13 million at Dec. 31, 2018 and Dec 31, 2017, respectively.

As the IRS Appeals and federal and state audits progress and other state audits resume, 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)	2018	2017	2016
Payable for interest related to unrecognized tax benefits at Jan. 1	$ —	$ (3)	$ —
Interest income (expense) related to unrecognized tax benefits	—	3	(3)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ —	$ —	$ (3)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2018, 2017 or 2016.

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)	2018	2017
Federal NOL carryforward	$ —	$ 1,072
Federal tax credit carryforwards	553	517
Valuation allowances for federal credit carryforwards	(5)	(5)
State NOL carryforwards	1,104	1,592
Valuation allowances for state NOL carryforwards	(50)	(55)
State tax credit carryforwards, net of federal detriment (a)	89	90
Valuation allowances for state credit carryforwards, net of federal benefit (b)	(69)	(68)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2018 and 2017.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $18 million as of Dec. 31, 2018 and 2017.

Federal carryforward periods expire between 2021 and 2038 and state carryforward periods expire between 2019 and 2037.

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:

	2018	2017 (a)	2016 (a)
Federal statutory rate	21.0%	35.0%	35.0%
State income tax on pretax income, net of federal tax effect	5.0	4.1	4.1
Increases (decreases) in tax from:			
Regulatory differences - ARAM (b)	(5.8)	(0.1)	(0.1)
Wind production tax credits recognized	(5.2)	(4.7)	(3.4)
Other tax credits recognized, net of federal income tax expense	(2.0)	(1.0)	(0.8)
Regulatory differences - other utility plant items	(1.0)	(0.7)	(0.5)
Regulatory differences - Deferral of ARAM (c)	0.6	—	—
Change in unrecognized tax benefits	0.4	(0.6)	0.2
Tax reform	—	1.4	—
Other, net	(0.4)	(1.3)	(0.4)
Effective income tax rate	12.6%	32.1%	34.1%

(a) Prior periods have been reclassified to conform to current year presentation.

(b) ARAM is a method to flow back excess deferred taxes to customers.

(c) ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Current federal tax (benefit) expense	$ (34)	$ 1	$ (3)
Current state tax expense (benefit)	8	(11)	(4)
Current change in unrecognized tax (benefit) expense	(6)	(83)	6
Deferred federal tax expense	122	460	477
Deferred state tax expense	85	107	112
Deferred change in unrecognized tax expense (benefit)	11	73	(2)
Deferred investment tax credits	(5)	(5)	(5)
Total income tax expense	$ 181	$ 542	$ 581

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2018	2017	2016
Deferred tax expense (benefit) excluding items below	$ 320	$(2,939)	$ 631
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(102)	3,583	(45)
Tax (expense) benefit allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	—	(4)	1
Deferred tax expense	$ 218	$ 640	$ 587

Components of net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 5,082	$ 4,960
Regulatory assets	599	565
Pension expense	178	199
Other	64	57
Total deferred tax liabilities	$ 5,923	$ 5,781
Deferred tax assets:		
Regulatory liabilities	$ 879	$ 886
Tax credit carryforward	642	607
NOL carryforward	51	293
NOL and tax credit valuation allowances	(79)	(77)
Other employee benefits	124	132
Deferred ITCs	16	17
Rate refund	60	10
Other	65	68
Total deferred tax assets	$ 1,758	$ 1,936
Net deferred tax liability	$ 4,165	$ 3,845

8. Share-Based Compensation

Incentive Plans Including Share-Based Compensation — Xcel Energy Inc. has three incentive plans that include share-based payment elements. Plans and authorized equity shares for awards:

- Omnibus Incentive Plan - 7.0 million shares;
- Long-Term Incentive Plan - 8.3 million shares; and,
- Executive Annual Incentive Award Plan - 1.2 million shares.

Restricted Stock — The Executive Annual Incentive Award Plan and Omnibus Incentive Plan allow 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 Inc.'s stock at the grant date.

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2018	2017	2016
Granted shares	18	15	20
Grant date fair value	$ 44.68	$ 42.00	$ 38.82

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2018	44	$ 39.71
Granted	18	44.68
Forfeited	—	—
Vested	(27)	37.25
Dividend equivalents	1	46.27
Nonvested restricted stock at Dec. 31, 2018	36	44.29

Other Equity Awards — Xcel Energy Inc.'s Board of Directors has granted equity awards under the Xcel Energy Inc. Long-Term Incentive Plan and the Omnibus Incentive Plan. These plans include various vesting conditions and performance goals. At the end of the restricted period, such grants will be awarded if the 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 0.3 million time-based equity shares subject only to service conditions were granted annually in 2018, 2017 and 2016, respectively.

The performance conditions for a portion of the awards granted from 2016 to 2018 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 percent depending on achievement.

Equity award units granted to employees (excluding restricted stock):

(Units in Thousands)	2018	2017	2016
Granted units	500	503	522
Weighted average grant date fair value	$ 47.60	$ 41.02	$ 36.00

Equity awards vested:

(Units in Thousands)	2018	2017	2016
Vested Units	475	467	530
Total Fair Value	$ 23,393	$ 22,459	$ 21,575

Changes in the nonvested portion of equity award units for 2018:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2018	995	$ 38.48
Granted	500	47.60
Forfeited	(126)	41.74
Vested	(475)	35.92
Dividend equivalents	45	40.74
Nonvested Units at Dec. 31, 2018	939	44.30

Stock Equivalent Units — Non-employee members of Xcel Energy Inc. 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 Xcel Energy Inc. 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)	2018	2017	2016
Granted units	36	51	49
Weighted average grant date fair value	$ 45.44	$ 46.05	$ 40.68

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2018	753	$ 29.83
Granted	36	45.44
Units distributed	(123)	31.21
Dividend equivalents	22	46.40
Stock equivalent units at Dec. 31, 2018	688	30.93

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Long-Term Incentive Plan and Omnibus Incentive Plan. The plans allow 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 22-member utilities peer group for 2016 - 2018 awards. Potential payouts of the awards range from zero to 200%.

TSR liability awards granted:

(In Thousands)	2018	2017	2016
Awards granted	239	240	264

TSR liability awards settled:

(In Thousands)	2018	2017	2016
Awards settled	482	454	354
Settlement amount (cash, common stock and deferred amounts)	$ 21,534	$ 19,083	$ 13,724

TSR liability awards of $8 million were settled in cash in 2018.

Share-Based Compensation Expense — Vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target, other than for restricted stock. Additionally, approximately 0.3 million of equity award units were granted annually in 2016 - 2018, 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)	2018	2017	2016
Compensation cost for share-based awards [(a)]	$ 45	$ 57	$ 41
Tax benefit recognized in income	12	22	16

(a) Compensation costs for share-based payment are included in O&M expense.

There was approximately $38 million in 2018 and $44 million in 2017 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 during the period. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding during the period. 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 Inc.'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 awards. Restricted stock issued to employees under the Xcel Energy Inc. 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; and,
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

Diluted common shares outstanding included common stock equivalents of 0.5 million, 0.6 million and 0.7 million shares for 2018, 2017 and 2016.

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 funds 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 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 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 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 insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Fair Value Measurements

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 escrow and investment targets by asset class for both the escrow and 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 $450 million and $560 million as of Dec. 31, 2018 and 2017, respectively, and unrealized losses were $45 million and $7 million as of Dec. 31, 2018 and 2017, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

	Dec. 31, 2018					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 24	$ 24	$ —	$ —	$ —	$ 24
Commingled funds	758	79	—	—	819	898
Debt securities	466	—	436	—	—	436
Equity securities	401	697	—	—	—	697
Total	$ 1,649	$ 800	$ 436	$ —	$ 819	$ 2,055

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $141 million of equity investments in unconsolidated subsidiaries and $121 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2017					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 29	$ 29	$ —	$ —	$ —	$ 29
Commingled funds	701	223	—	—	659	882
Debt securities	438	—	441	—	—	441
Equity securities	423	791	—	—	—	791
Total	$ 1,591	$ 1,043	$ 441	$ —	$ 659	$ 2,143

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $140 million of equity investments in unconsolidated subsidiaries and $114 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2018 and 2017, there were no 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, 2018:

	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 . . .	$ 10	$ 107	$ 211	$ 108	$ 436

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, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 16	$ 16	$ —	$ —	$ 16
Mutual funds	52	51	—	—	51
Total.	$ 68	$ 67	$ —	$ —	$ 67

	Dec. 31, 2017				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 12	$ 12	$ —	$ —	$ 12
Mutual funds	47	50	—	—	50
Total.	$ 59	$ 62	$ —	$ —	$ 62

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative 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 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, 2018, accumulated other comprehensive losses related to interest rate derivatives included $3 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, 2018, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $300 million. These interest rate derivatives were designated as hedges, and as such, changes in fair value are recorded to other comprehensive income.

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.

As of Dec. 31, 2018, Xcel Energy had no vehicle fuel contracts designated as cash flow hedges. 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. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2018 and 2017.

As of Dec. 31, 2018, there were no net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.

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 as of Dec. 31:

(Amounts in Millions) [(a)] [(b)]	2018	2017
MWh of electricity.	87	68
MMBtu of natural gas	92	37

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are 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 in 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, 2018, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $96 million or 43% of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Three of the 10 most significant counterparties, comprising $20 million or 9% 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 $12 million or 5% of this credit exposure, had credit quality less than investment grade, based on Xcel Energy's internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel 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)	2018	2017	2016
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (58)	$ (51)	$ (55)
After-tax net unrealized losses related to derivatives accounted for as hedges	(5)	—	—
After-tax net realized losses on derivative transactions reclassified into earnings	3	3	4
Adoption of ASU. 2018-02 (a)	—	(10)	—
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (60)	$ (58)	$ (51)

(a) In 2017, Xcel Energy implemented ASU No. 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

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, 2018		
Derivatives designated as cash flow hedges		
Interest rate	$ (7)	$ —
Total	$ (7)	$ —
Other derivative instruments		
Electric commodity	$ —	$ 1
Natural gas commodity	—	10
Total	$ —	$ 11
Year Ended Dec. 31, 2017		
Other derivative instruments		
Electric commodity	$ —	$ 10
Natural gas commodity	—	(13)
Total	$ —	$ (3)
Year Ended Dec. 31, 2016		
Other derivative instruments		
Electric commodity	$ —	$ 17
Natural gas commodity	—	1
Total	$ —	$ 18

	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, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 (a)	$ —	$ —
Total	$ 4	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 14 (b)
Electric commodity	—	(1) (c)	—
Natural gas commodity	—	(6) (d)	(4) (d)
Total	$ —	$ (7)	$ 10
Year Ended Dec. 31, 2017			
Derivatives designated as cash flow hedges			
Interest rate	$ 5 (a)	$ —	$ —
Total	$ 5	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 10 (b)
Electric commodity	—	(15) (c)	—
Natural gas commodity	—	3 (d)	(6) (d)
Total	$ —	$ (12)	$ 4
Year Ended Dec. 31, 2016			
Derivatives designated as cash flow hedges			
Interest rate	$ 6 (a)	$ —	$ —
Total	$ 6	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 2 (b)
Electric commodity	—	(8) (c)	—
Natural gas commodity	—	15 (d)	(8) (d)
Total	$ —	$ 7	$ (6)

(a) Amounts recorded to interest charges.

(b) Amounts 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) Amounts 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) Amounts for the year ended Dec. 31, 2018 included $1 million of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such gains and losses for the years ended Dec. 31, 2017 and 2016 were immaterial. Remaining settlement losses for the years ended Dec. 31, 2018, 2017 and 2016 related to natural gas operations and were 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, 2018, 2017 and 2016.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-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, or for cross default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2018 and 2017, there were no derivative instruments in a liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These 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, 2018 and 2017.

Recurring Fair Value Measurements — Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis:

	Dec. 31, 2018						Dec. 31, 2017					
	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												
Commodity trading	$ 4	$ 92	$ 2	$ 98	$ (44)	$ 54	$ 2	$ 22	$ —	$ 24	$ (15)	$ 9
Electric commodity	—	—	25	25	—	25	—	—	32	32	(2)	30
Natural gas commodity	—	4	—	4	—	4	—	—	—	—	—	—
Total current derivative assets	$ 4	$ 96	$ 27	$ 127	$ (44)	83	$ 2	$ 22	$ 32	$ 56	$ (17)	39
PPAs [(b)]						4						5
Current derivative instruments						$ 87						$ 44
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ —	$ 27	$ 5	$ 32	$ (14)	$ 18	$ —	$ 31	$ 5	$ 36	$ (7)	$ 29
Total noncurrent derivative assets	$ —	$ 27	$ 5	$ 32	$ (14)	18	$ —	$ 31	$ 5	$ 36	$ (7)	29
PPAs [(b)]						16						19
Noncurrent derivative instruments						$ 34						$ 48

	Dec. 31, 2018						Dec. 31, 2017					
	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												
Derivatives designated as cash flow hedges:												
Interest rate	$ —	$ 7	$ —	$ 7	$ —	$ 7	$ —	$ —	$ —	$ —	$ —	$ —
Other derivative instruments:												
Commodity trading	4	88	2	94	(60)	34	2	18	—	20	(15)	5
Electric commodity	—	—	—	—	—	—	—	—	2	2	(2)	—
Natural gas commodity	—	—	—	—	—	—	—	1	—	1	—	1
Total current derivative liabilities	$ 4	$ 95	$ 2	$ 101	$ (60)	41	$ 2	$ 19	$ 2	$ 23	$ (17)	6
PPAs [(b)]						20						23
Current derivative instruments						$ 61						$ 29
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ —	$ 18	$ 1	$ 19	$ 17	$ 36	$ —	$ 24	$ —	$ 24	$ (10)	$ 14
Total noncurrent derivative liabilities	$ —	$ 18	$ 1	$ 19	$ 17	36	$ —	$ 24	$ —	$ 24	$ (10)	14
PPAs [(b)]						93						112
Noncurrent derivative instruments						$ 129						$ 126

(a) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet 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, 2018 and 2017. At Dec. 31, 2018 and 2017, derivative assets and liabilities include $32 million and $0 million of obligations to return cash collateral, respectively. At Dec. 31, 2018 and 2017, derivative assets and liabilities include rights to reclaim cash collateral of $15 million and $3 million, respectively. Counterparty netting excludes 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, 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:

	Year Ended Dec. 31		
(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 35	$ 17	$ 18
Purchases	59	82	35
Settlements	(59)	(97)	(89)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(a)]	(1)	5	—
Net (losses) gains recognized as regulatory assets and liabilities	(5)	28	53
Balance at Dec. 31	$ 29	$ 35	$ 17

(a) Amounts relate to commodity derivatives held at the end of the period.

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 2016 - 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2018		2017	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 16,209	$ 16,755	$ 14,977	$ 16,531

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, 2018 and 2017, 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, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. 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 that were participants 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, 2018 and 2017 were $33 million and $37 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2018 and $5 million in 2017.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan, supplemented by Xcel Energy's consolidated operating cash flows.

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- NSP-Minnesota and NSP-Wisconsin discontinued subsidizing health care benefits for non-bargaining employees retiring after 1998 and for bargaining employees who retired after 1999.
- Xcel Energy discontinued subsidizing health care benefits for nonbargaining employees of the former NCE who retired after June 30, 2003.
- Xcel Energy discontinued health care benefits for SPS bargaining employees hired after Jan. 1, 2012.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20 years or longer period, 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 2018 were below the assumed level of 6.87%;
- Investment returns in 2017 were above the assumed level of 6.87%;
- Investment returns in 2016 were below the assumed level of 6.87%; and,
- In 2019, Xcel Energy's expected investment-return assumption is 6.87%.

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 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

The following presents, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

	Dec. 31, 2018 [a]					Dec. 31, 2017 [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	$ 137	$ —	$ —	$ —	$ 137	$ 196	$ —	$ —	$ —	$ 196
Commingled funds:	914	—	—	987	1,901	1,054	—	—	1,075	2,129
Debt securities:	—	621	—	—	621	—	673	—	—	673
Equity securities:	106	—	—	—	106	114	—	—	—	114
Other	2	5	—	(30)	(23)	(29)	4	—	1	(24)
Total	$ 1,159	$ 626	$ —	$ 957	$ 2,742	$ 1,335	$ 677	$ —	$ 1,076	$ 3,088

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

The following presents, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2018 [a]					Dec. 31, 2017 [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	$ 19	$ —	$ —	$ —	$ 19	$ 29	$ —	$ —	$ —	$ 29
Insurance contracts	—	45	—	—	45	—	50	—	—	50
Commingled funds	133	—	—	40	173	148	—	—	—	148
Debt securities	—	179	—	—	179	—	198	—	—	198
Equity securities	—	—	—	—	—	35	—	—	—	35
Other	—	1	—	—	1	—	1	—	—	1
Total	$ 152	$ 225	$ —	$ 40	$ 417	$ 212	$ 249	$ —	$ —	$ 461

(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 2018 and 2017.

Funded Status — 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)	2018	2017	2018	2017
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,828	$ 3,682	$ 621	$ 603
Service cost	94	94	2	2
Interest cost	133	147	22	24
Plan amendments	—	(13)	—	—
Actuarial (gain) loss	(224)	259	(62)	33
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	1	1
Benefit payments [a]	(354)	(341)	(50)	(50)
Obligation at Dec. 31	$ 3,477	$ 3,828	$ 542	$ 621
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 3,088	$ 2,856	$ 461	$ 442
Actual return on plan assets	(142)	411	(13)	41
Employer contributions	150	162	11	20
Plan participants' contributions	—	—	8	8
Benefit payments	(354)	(341)	(50)	(50)
Fair value of plan assets at Dec. 31	$ 2,742	$ 3,088	$ 417	$ 461
Funded status of plans at Dec. 31	$ (735)	$ (740)	$ (125)	$ (160)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Current liabilities	$ —	$ —	$ (7)	$ (3)
Noncurrent liabilities	(735)	(740)	(118)	(157)
Net amounts recognized	$ (735)	$ (740)	$ (125)	$ (160)

(a) Includes approximately $198 million in 2018 and $174 million in 2017 of lump-sum benefit payments used in the determination of a settlement charge.

(Millions of Dollars)	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	4.31%	3.63%	4.32%	3.62%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	RP-2014	RP-2014	RP-2014	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50%	7.00%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.35%	5.50%
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 $3,275 million and $3,612 million as of Dec. 31, 2018 and 2017, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income 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 2018	Pension Benefits 2017	Pension Benefits 2016	Postretirement Benefits 2018	Postretirement Benefits 2017	Postretirement Benefits 2016
Service cost	$ 94	$ 94	$ 92	$ 2	$ 2	$ 2
Interest cost	133	147	160	22	24	26
Expected return on plan assets	(209)	(209)	(210)	(26)	(25)	(25)
Amortization of prior service credit	(5)	(2)	(2)	(11)	(11)	(11)
Amortization of net loss	111	107	97	8	7	4
Settlement charge [(a)]	91	81	—	—	—	—
Net periodic pension cost (credit)	215	218	137	(5)	(3)	(4)
Costs not recognized due to effects of regulation	(75)	(79)	(15)	2	—	—
Net benefit cost (credit) recognized for financial reporting	$ 140	$ 139	$ 122	$ (3)	$ (3)	$ (4)
Significant Assumptions Used to Measure Costs:						
Discount rate	3.63%	4.13%	4.66%	3.62%	4.13%	4.65%
Expected average long-term increase in compensation level	3.75	3.75	4.00	—	—	—
Expected average long-term rate of return on assets	6.87	6.87	6.87	5.30	5.80	5.80

(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 2018 and 2017, as a result of lump-sum distributions during the 2018 and 2017 plan years, Xcel Energy recorded a total pension settlement charge of $91 million in 2018 and $81 million in 2017, the majority of which was not recognized due to the effects of regulation. A total of $11 million and $8 million was recorded in the consolidated statements of income in 2018 and 2017, respectively.

(Millions of Dollars)	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 1,633	$ 1,709	$ 116	$ 147
Prior service credit	(20)	(25)	(33)	(44)
Total	$ 1,613	$ 1,684	$ 83	$ 103
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	$ 94	$ 100	$ —	$ —
Noncurrent regulatory assets	1,446	1,511	89	107
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(10)	(10)
Deferred income taxes	19	19	1	2
Net-of-tax accumulated other comprehensive income	54	54	4	5
Total	$ 1,613	$ 1,684	$ 83	$ 103
Measurement date	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017

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 2016 - 2019 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $150 million in January 2019;
- $150 million in 2018;
- $162 million in 2017; and,
- $125 million in 2016.

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 $11 million during 2019;
- $11 million during 2018;
- $20 million during 2017; and,
- $18 million during 2016.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Domestic and international equity securities	36%	36%	18%	24%
Long-duration fixed income securities	30	27	—	—
Short-to-intermediate fixed income securities	17	20	70	60
Alternative investments	15	15	8	9
Cash	2	2	4	7
Total	100%	100%	100%	100%

Plan Amendments — The Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) were amended in 2017 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. In 2016, the Xcel Energy Pension Plan was amended to change the discount rate basis for lump-sum conversion to annuity participants and annuity conversion to lump-sum participants. Annual credits contributed to the PSCo Bargaining Plan retirement spending account also increased.

In 2018 and 2017, there were no plan amendments made which affected the postretirement benefit obligation.

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
2019	$ 281	$ 45	$ 2	$ 43
2020	260	45	2	43
2021	259	45	2	43
2022	260	44	2	42
2023	259	43	2	41
2024-2028	1,238	197	13	184

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $38 million in 2018, $37 million in 2017 and $36 million in 2016.

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 that are being defended and handled in the ordinary course of business. Assessing whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including 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 the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are 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 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.

In the fourth quarter of 2018, four cases were settled. Two cases remain active which include an MDL matter consisting of a Colorado class (Breckenridge) and a Wisconsin class (Arandell Corp.).

Breckenridge/Colorado — Case has been remanded to the MDL panel, and is expected to be referred back to the U.S. District Court in Colorado. Xcel Energy has concluded that a loss is remote.

Arandell Corp. — In November 2017, the U.S. District Court in Nevada granted summary judgment against two plaintiffs in the Arandell Corp. case in favor of Xcel Energy and NSP-Wisconsin, leaving only three individual plaintiffs remaining in the litigation. In addition, the plaintiffs' motions for class certification and remand back to originating courts were denied in March 2017.

Plaintiffs have asked the lower court to remand the cases back to the court where the actions were originally filed anticipating class certification. A hearing date has not been set. Xcel Energy has concluded that a loss is remote.

Line Extension Disputes — In December 2015, the DRC filed a lawsuit seeking monetary damages in the Denver District Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric and gas service agreements. The dispute involves claims by over fifty developers. In February 2018, the Colorado Supreme Court denied DRC's petition to appeal the Denver District Court's dismissal of the lawsuit, effectively terminating this litigation. However, in January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so.

This claim is substantially similar to the arguments previously raised by DRC. PSCo filed a motion to dismiss this claim, which was granted in May 2018. DRC subsequently filed an appeal to the Colorado Court of Appeals with its opening brief in January 2019 and PSCo filed its answer brief in February 2019. It is uncertain when a decision will be rendered.

PSCo has concluded that a loss is remote with respect to both of these matters as the service agreements were developed to implement CPUC approved tariffs and PSCo has complied with the tariff provisions. If a loss were sustained, PSCo believes it would be allowed to recover costs through traditional regulatory mechanisms. Amount or range in dispute is presently unknown and no accrual has been recorded for this matter.

Rate Matters

NSP-Minnesota — ***Sherco*** — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, SMMPA (Co-owner of Sherco Unit 3) and insurance companies against GE.

In 2018, NSP-Minnesota and SMMPA reached a settlement with GE. NSP-Minnesota has notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the FCA.

The insurance providers continued their litigation against GE and the case went to trial. In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.

In January 2019, the DOC recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The OAG recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals.

NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.

MISO ROE Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin. The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%.

In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) 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 FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.

In October 2018, the FERC issued a NETO base ROE order that addressed the D.C. Circuit's actions on Opinion No. 531. Under a new proposed two step ROE approach, the FERC has indicated an intention to dismiss an ROE complaint if the existing ROE falls within the range of just and reasonable ROEs based on equal weighting of the DCF, CAPM, and Expected Earnings models. The FERC proposes that if necessary, it would then set a new ROE by averaging the results of these models plus a Risk Premium model.

With respect to the MISO TOs, the FERC subsequently made preliminary determinations in a November 2018 order that the MISO base ROE in effect for the first complaint period (12.38%) was outside the range of reasonableness, and should be reduced. The FERC indicated its preliminary analysis using the new ROE approach resulted in a base ROE of 10.28% for the first compliant period, compared to the previously ordered base ROE of 10.32%. A procedural schedule has been set for the first half of 2019, with the FERC expected to act no earlier than the second half of 2019. NSP-Minnesota has recognized a current refund liability consistent with its best estimate of the final ROE.

SPP OATT Upgrade Costs — Under the SPP OATT, costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover these previously unbilled charges. SPP subsequently billed SPS approximately $13 million for these charges.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these previously unbilled charges was remanded to the FERC. Assessment of these charges (from 2008 - 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.

In October 2017, SPS filed a separate complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC has granted a rehearing for further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, it will seek to recover or refund the differential in future rate proceedings.

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.

MGP Sites

Ashland MGP Site — NSP-Wisconsin was named a responsible party for contamination at the Ashland/Northern States Power Lakefront Superfund Site (the Site) in Ashland, Wisconsin. Remediation and restoration activities are anticipated to be completed in 2019 and groundwater treatment activities will continue for many years.

Current cost estimate for remediation of the entire site is approximately $192 million, of which approximately $165 million has been spent. As of Dec. 31, 2018 and 2017, NSP-Wisconsin recorded a total liability of $27 million and $30 million, respectively, for the entire site.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In 2012, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a 10-year period and to apply a 3% carrying cost to the unamortized regulatory asset.

MGP, Landfill or Disposal Sites — Xcel Energy is currently investigating or remediating twelve MGP, landfill or other disposal sites across its service territories, in addition to the Ashland MGP Site, and these activities will continue through at least 2019. Xcel Energy accrued $9 million as of Dec. 31, 2018 and $19 million as of Dec. 31, 2017 for these sites. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of the costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the EPA published the CCR Rule. Litigation was brought challenging the rule in the D.C. Circuit.

Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Xcel Energy has identified at least two sites in Colorado where SSLs exist in the groundwater near landfills and/or impoundments. Xcel Energy has completed removal of CCR from these impoundments and plans to close these landfills. By the end of 2019, only nine of Xcel Energy's regulated ash units are expected to be in operation. Xcel Energy is conducting additional groundwater sampling and will evaluate whether corrective action is required at any CCR landfills or surface impoundments.

Until Xcel Energy completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows. In August 2018, the D.C. Circuit ruled that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. Litigation is ongoing regarding the deadline for closing or retrofitting these impoundments. The decision will require Xcel Energy to expedite closure of one impoundment in Minnesota (see ARO removal costs below) and will require construction of a new impoundment, which is estimated to cost $6 million.

Federal CWA WOTUS Rule — In 2015, the EPA and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". The Rule has been subject to significant litigation and is currently stayed in a portion of the country. Xcel Energy cannot estimate potential impacts until the legal and administrative processes are finalized, but expects costs will be recoverable through regulatory mechanisms.

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 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, Xcel Energy estimates that ELG compliance will cost approximately $12 million to complete. The EPA, however, is conducting a rulemaking process to potentially revise the effluent limitations and pretreatment standards, which may impact compliance costs. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

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 cost for complying with impingement and entrainment requirements is approximately $40 million, to be incurred between 2019 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators 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 approximately $200 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, NO_X and PM emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress.

The requirements of the first regional haze plans developed by Minnesota and Colorado have been approved and implemented. Texas' first regional haze plan has undergone federal review as described below.

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 United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The 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. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. 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. It is not known when the EPA will make a final decision on this proposal.

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, with compliance 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 are needed at Tolk under the "reasonable progress" requirements. The EPA has not announced a schedule for acting 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 an exception. The EPA issued final designations which found the area near the SPS Harrington plant as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020.

If the area near the Harrington plant is designated nonattainment in 2020, the TCEQ will need to develop an implementation plan, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. Xcel Energy cannot evaluate the impacts until the final designation is made and any required state plans are developed. Xcel Energy believes that should SO_2 control systems be required for a plant, 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 the NSP-Minnesota nuclear generating plants, Monticello and PI.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was $2.1 billion for 2018 and 2017.

Xcel Energy's AROs were as follows:

	Dec. 31, 2018					
(Millions of Dollars)	Jan. 1, 2018	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2018
Electric						
Nuclear	$1,874	$ —	$ —	$ 94	$ —	$1,968
Steam, hydro, and other production	192	—	(14)	8	(9)	177
Wind	96	12	—	4	7	119
Distribution	21	—	—	1	20	42
Miscellaneous	5	—	—	—	2	7
Natural gas						
Transmission and distribution	282	—	—	13	(46)	249
Miscellaneous	4	—	—	—	—	4
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	—	1	—	—	—	1
Total liability	$2,475	$ 13	$ (14)	$ 120	$ (26)	$2,568

(a) Amounts incurred related to the PSCo Rush Creek wind farm and Nicollet Projects community solar gardens, which were placed in service in 2018.

(b) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(c) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by increased discount rates. Changes in electric distribution AROs primarily related to increased labor costs.

	Dec. 31, 2017					
(Millions of Dollars)	Jan. 1, 2017	Amounts Incurred	Amounts Settled (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2017
Electric						
Nuclear	$2,249	$ —	$ —	$ 114	$ (489)	$1,874
Steam, hydro, and other production	205	1	(29)	9	6	192
Wind	92	—	—	4	—	96
Distribution	20	—	—	1	—	21
Miscellaneous	5	—	—	—	—	5
Natural gas						
Transmission and distribution	205	—	—	8	69	282
Miscellaneous	4	—	—	—	—	4
Common						
Miscellaneous	2	—	(1)	—	—	1
Total liability	$2,782	$ 1	$ (30)	$ 136	$ (414)	$2,475

(a) Amounts settled related to asbestos abatement, closure of ash containment facilities, and removal and disposal of storage tanks and other above ground equipment.

(b) In 2017, AROs were revised for changes in timing and estimates of cash flows. Nuclear AROs decreased due to updated assumptions. Changes in gas transmission and distribution AROs were primarily related to increased labor costs.

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, 2018. Therefore, an ARO was not recorded for these facilities.

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of its utility subsidiaries that are recovered currently in rates. Removal costs have accumulated based on varying rates as authorized by the appropriate regulatory entities. The utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accumulated balances by entity at Dec. 31:

(Millions of Dollars)	2018	2017
NSP-Minnesota	$ 485	$ 442
PSCo	344	346
SPS	188	197
NSP-Wisconsin	158	146
Total Xcel Energy	$ 1,175	$ 1,131

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $14.1 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 $13.6 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 licensed 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 by the NRC and state premium taxes. The NRC's last adjustment was effective November 2018.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, 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 approximately $18 million for business interruption insurance and $39 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 44 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.

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.

Obligation for decommissioning is expected to be funded 100% by the external decommissioning trust fund. This 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 has accumulated $2.1 billion of assets held in external decommissioning trusts in 2018. 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 (ARO).

	Regulatory Basis	
(Millions of Dollars)	**2018**	**2017**
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	539	396
Estimated decommissioning cost obligation (in current dollars)	3,551	3,408
Effect of escalating costs to payment date	7,654	7,797
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 3.33% and 2.80% for 2018 and 2017, respectively)	(6,911)	(6,398)
Discounted decommissioning cost obligation	$ 4,294	$ 4,807
Assets held in external decommissioning trust	$ 2,055	$ 2,143
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,239	2,664

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)	**2018**	**2017**
Discounted decommissioning cost obligation - regulated basis .	$ 4,294	$ 4,807
Differences in discount rate and market risk premium	(1,447)	(1,403)
O&M costs not included for GAAP	(879)	(1,041)
ARO differences between 2017 and 2014 cost studies	—	(489)
Nuclear production decommissioning ARO - GAAP	$ 1,968	$ 1,874

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	**2018**	**2017**	**2016**
Annual decommissioning recorded as depreciation expense: [(a) (b)]	$ 20	$ 20	$ 20

[(a)] Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

[(b)] Decommissioning expenses in 2018, 2017 and 2016 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2018, 2017 and 2016. The 2017 filing, effective Jan. 1, 2019, has been approved by the MPUC.

Leases — Xcel Energy has three leases accounted for as capital leases. The assets and liabilities of a capital lease are recorded at the lower of fair market value of the leased asset or the present value of future lease payments and are amortized over the term of the contract.

WYCO is 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 arrangement with CIG as a capital lease. Xcel Energy Inc. eliminates 50% of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

PSCo records amortization for its capital lease assets as electric fuel and purchased power and cost of natural gas sold and transported on the consolidated statements of income.

Property held under capital leases:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Gas storage facilities	$ 201	$ 201
Gas pipeline	21	21
Property held under capital leases	222	222
Accumulated depreciation	(77)	(71)
Total property held under capital leases, net	$ 145	$ 151

Remaining leases, primarily for real estate and certain natural gas generating facilities operated under PPAs, as well as railcars, aircraft and other equipment, are accounted for as operating leases.

Total expenses (including capacity payments) under operating lease obligations for Xcel Energy and the corresponding capacity payments for PPAs accounted for as operating leases for the year ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Total expense	$ 248	$ 246	$ 255
Capacity payments	210	210	216

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases.

Future commitments under operating and capital leases:

(Millions of Dollars)	Operating Leases	PPA [(a) (b)] Operating Leases	Total Operating Leases	Capital Leases
2019	$ 32	$ 207	$ 239	$ 14
2020	26	208	234	14
2021	25	210	235	14
2022	24	197	221	12
2023	22	186	208	12
Thereafter	154	883	1,037	220
Total minimum obligation				286
Interest component of obligation				(201)
Present value of minimum obligation				$ 85 [(c)]

(a) Amounts do not include PPAs accounted for as executory contracts.
(b) PPA operating leases contractually expire through 2034.
(c) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

Non-Lease PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements, meet 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 contain minimum energy purchase commitments. 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 our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $131 million, $168 million and $191 million in 2018, 2017 and 2016, respectively.

At Dec. 31, 2018, 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)]
2019	$ 86	$ 99
2020	70	109
2021	78	157
2022	77	173
2023	79	177
Thereafter	125	328
Total	$ 515	$ 1,043

(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 2019 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, 2018:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2019	$ 461	$ 127	$ 416	$ 268
2020	260	51	263	255
2021	149	99	254	245
2022	109	79	114	234
2023	61	99	60	170
Thereafter	108	337	—	923
Total	$ 1,148	$ 792	$ 1,107	$ 2,095

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. Xcel Energy's utility subsidiaries had approximately 3,770 MW and 3,537 MW of capacity under long-term PPAs at Dec. 31, 2018 and 2017, respectively, with entities that have been determined to be VIEs. Agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO 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.

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, 2018	Dec. 31, 2017
Current assets	$ 5	$ 6
Property, plant and equipment, net	42	46
Other noncurrent assets	1	1
Total assets	$ 48	$ 53
Current liabilities	$ 7	$ 9
Mortgages and other long-term debt payable	26	26
Other noncurrent liabilities	—	1
Total liabilities	$ 33	$ 36

Other

Technology Agreements — Xcel Energy has a contract that extends through December 2022 with IBM for information technology services. Contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50% of the contract value for early termination. Xcel Energy capitalized or expensed $81 million, $98 million and $119 million associated with the IBM contract in 2018, 2017 and 2016, respectively.

Xcel Energy's contract with Accenture for information technology services extends through December 2020. Contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $46 million, $16 million and $35 million associated with the Accenture contract in 2018, 2017 and 2016, respectively.

Committed minimum payments under these obligations:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2019	$ 30	$ 11
2020	16	11
2021	16	—
2022	7	—
2023	—	—
Thereafter	—	—

Guarantees and Bond Indemnifications — Xcel Energy Inc. and its subsidiaries enter into contractual guarantees in limited circumstances. Xcel Energy Inc. may guarantee the subsidiaries' obligations in the event they fail to perform and may provide guarantees in certain indemnification agreements. Xcel Energy Inc.'s guarantees from the subsidiaries are not individually material with maximum potential liability totaling $6 million as of Dec. 31, 2018. Payment for these guarantees is considered remote.

13. Other Comprehensive Income

Changes in accumulated other comprehensive (loss), net of tax, for the years ended Dec. 31:

	2018		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (58)	$ (67)	$ (125)
Other comprehensive loss before reclassifications (net of taxes of $(2) and $(2), respectively)	(5)	(6)	(11)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $1 and $0, respectively)	3 [a]	—	3
Amortization of net actuarial loss (net of taxes of $0 and $3, respectively)	—	9 [b]	9
Net current period other comprehensive income (loss)	(2)	3	1
Accumulated other comprehensive loss at Dec. 31	$ (60)	$ (64)	$ (124)

(Millions of Dollars)	2017 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (51)	$ (59)	$ (110)
Other comprehensive loss before reclassifications (net of taxes of $0 and $(2), respectively)	—	(3)	(3)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $2 and $0, respectively)	3 (a)	—	3
Amortization of net actuarial loss (net of taxes of $0 and $5, respectively)	—	7 (b)	$ 7
Net current period other comprehensive income	3	4	7
Adoption of ASU No. 2018-02 (c)	(10)	(12)	(22)
Accumulated other comprehensive loss at Dec. 31	$ (58)	$ (67)	$ (125)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs.

(c) In 2017, Xcel Energy implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

14. Segments and Related Information

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 are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. 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.
- *All Other* - Operating segments with revenues below the necessary quantitative thresholds are included in this category. Those segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $141 million and $140 million as of Dec. 31, 2018 and 2017, 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)	2018	2017	2016
Regulated Electric			
Operating revenues from external customers	$ 9,719	$ 9,676	$ 9,500
Intersegment revenue	1	2	1
Total revenues	$ 9,720	$ 9,678	$ 9,501
Depreciation and amortization	1,421	1,298	1,136
Interest charges and financing costs	449	449	450
Income tax expense	187	528	567
Net income	1,177	1,066	1,067
Regulated Natural Gas			
Operating revenues from external customers	$ 1,739	$ 1,650	$ 1,531
Intersegment revenue	2	1	1
Total revenues	$ 1,741	$ 1,651	$ 1,532
Depreciation and amortization	212	174	160
Interest charges and financing costs	61	57	54
Income tax expense	28	23	76
Net income	187	182	124
All Other			
Total operating revenue	$ 79	$ 78	$ 76
Depreciation and amortization	9	7	7
Interest charges and financing costs	142	122	116
Income tax (benefit)	(34)	(9)	(62)
Net (loss)	(103)	(100)	(68)
Consolidated Total			
Total revenue	$ 11,540	$ 11,407	$ 11,109
Reconciling eliminations	(3)	(3)	(2)
Consolidated total revenue	$ 11,537	$ 11,404	$ 11,107
Depreciation and amortization	1,642	1,479	1,303
Interest charges and financing costs	652	628	620
Income tax expense	181	542	581
Net income	1,261	1,148	1,123

15. Summarized Quarterly Financial Data (Unaudited)

(Amounts in millions, except per share data)	Quarter Ended March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$ 2,951	$ 2,658	$ 3,048	$ 2,880
Operating income [(a)]	480	450	696	339
Net income	291	265	491	214
EPS total — basic	$ 0.57	$ 0.52	$ 0.96	$ 0.42
EPS total — diluted	0.57	0.52	0.96	0.42
Cash dividends declared per common share	0.38	0.38	0.38	0.38

(Amounts in millions, except per share data)	Quarter Ended March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Operating revenues	$ 2,946	$ 2,645	$ 3,017	$ 2,796
Operating income [(a)]	492	466	824	440
Net income	239	227	492	189
EPS total — basic	$ 0.47	$ 0.45	$ 0.97	$ 0.37
EPS total — diluted	0.47	0.45	0.97	0.37
Cash dividends declared per common share	0.36	0.36	0.36	0.36

(a) In 2018, Xcel Energy implemented ASU No. 2017-07 related to net periodic benefit cost, which resulted in retrospective reclassification of pension costs from O&M expense to other income.

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 chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of Dec. 31, 2018, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the chief executive officer and chief financial officer, of the effectiveness of its disclosure controls and the procedures, the chief executive officer and chief financial officer have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is 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, 2018 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 and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Item 9B — Other Information

None.

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 2019 Annual Meeting of Shareholders, which is 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 2019 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 2019 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 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

Item 15 — Exhibits, Financial Statement Schedules

1 Consolidated Financial Statements

Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2018.

Report of Independent Registered Public Accounting Firm — Financial Statements

Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting

Consolidated Statements of Income — For the three years ended Dec. 31, 2018, 2017, and 2016.

Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2018, 2017, and 2016.

Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2018, 2017, and 2016.

Consolidated Balance Sheets — As of Dec. 31, 2018 and 2017.

Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2018, 2017, and 2016.

2 Schedule I — Condensed Financial Information of Registrant.

Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2018, 2017 and 2016.

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	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated May 16, 2012	001-03034	3.01
3.02*	Bylaws of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated Feb. 17, 2016	001-03034	3.01
4.01*	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	001-03034	4.01
4.02*	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	001-03034	4.01
4.03*	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	001-03034	4.01
4.04*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.03
4.05*	Supplemental Indenture No. 5, dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated May 10, 2010	001-03034	4.01
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	001-03034	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	001-03034	4.01
4.08*	Supplemental Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated March 8, 2016	001-03034	4.02
4.09*	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	001-03034	4.01
4.10*	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	001-03034	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	001-03034	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	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	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	001-03034	10.17
10.06*+	First Amendment to Exhibit 10.02 dated Aug. 26, 2009	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06
10.07*+	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	001-03034	10.08
10.08*+	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	001-03034	Schedule 14A

10.09*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A
10.10*+	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	001-03034	Schedule 14A
10.11*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.12*+	First Amendment to Exhibit 10.11 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.13*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.14*+	First Amendment to Exhibit 10.08 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.15*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.16*+	First Amendment to Exhibit 10.09 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.21
10.17*+	Second Amendment to Exhibit 10.11 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.18*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.23
10.19*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2015	001-03034	Schedule 14A
10.20*+	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	001-03034	10.02
10.21*	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.03
10.22*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.28
10.23*+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.29
10.24*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.25*	Second Amendment and Restated Credit Agreement, dated as of June 20, 2016 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, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd. , as Document Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.01
10.26*+	Third Amendment to Exhibit 10.11 dated Sept. 30, 2016	Xcel Energy inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.27*+	Form of Xcel Energy, Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2016	001-03034	10.27
10.28*+	Fourth Amendment to Exhibit 10.11 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.29*	364-Day Term Loan Agreement dated Dec. 5, 2017 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent	Xcel Energy Inc. Form 8-K dated Dec. 5, 2017	001-03034	99.01
10.30*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30
10.31*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.32*	Forward Sale Agreement, dated Nov. 7, 2018, between Xcel Energy Inc. and Morgan Stanley &Co., LLC	Xcel Energy Inc. Form 8-K dated Nov. 7, 2018	001-03034	10.01
10.33*	Amended and Restated 364-Day Term Loan Agreement dated as of Dec. 4, 2018 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and MUFG Bank, Ltd. as Administrative Agent.	Xcel Energy Inc. Form 8-K dated Dec. 4, 2018	001-03034	99.01
10.34+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan			
10.35+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan			
10.36+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan			

NSP-Minnesota

4.11*	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	001-03034	4(b)(3)
4.12*	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	001-03034	4.11
4.13*	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	001-03034	4.12

4.14*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.51
4.15*	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	001-03034	4(b)(7)
4.16*	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	000-31709	4.63
4.17*	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	001-31387	4.01
4.18*	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	001-31387	4.01
4.19*	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	001-31387	4.01
4.20*	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	001-31387	4.01
4.21*	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	001-31387	4.01
4.22*	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	001-31387	4.01
4.23*	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	001-31387	4.01
4.24*	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	001-31387	4.01
4.25*	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	001-31387	4.01
4.26*	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 31, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	001-31387	4.01
4.27*	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	001-31387	4.01
10.37*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01
10.38*	Second Amendment and Restated Credit Agreement, dated as of June 20, 2016 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, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.02

NSP-Wisconsin

4.28*	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	001-03034	4(c)(3)
4.29*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	001-03140	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991	Xcel Energy Inc Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.05
4.31*	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	001-03140	4.01
4.32*	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	001-03140	4.01
4.33*	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	001-03140	4.01
4.34*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million in aggregate principal amount of 3.75% First Mortgage Bonds, Series due Dec. 1, 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	001-03140	4.01
4.35*	Supplemental Indenture dated as of Sept. 1, 2018 between Northern States Power Company and U.S. Bank National Association, as successor Trustee, creating 4.20% First Mortgage Bonds, Series due Sept. 1, 2048	NSP-Wisconsin to Form 8-K dated Sept. 12, 2018	001-03034	4.01
10.39*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01

10.40*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 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, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016		99.05
PSCo				
4.36*	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	001-03034	4(d)(3)
4.37*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 14, 1999 between PSCo and the Bank of New York	PSCo Form 8-K dated July 13, 1999	001-03280	4.1 4.2
4.38*	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	001-03280	4.01
4.39*	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 No. 18 due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series No. 19 due 2038	PSCo Form 8-K dated Aug. 6, 2008	001-03280	4.01
4.40*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $400 million principal amount of 5.125% First Mortgage Bonds, Series No. 20 due 2019	PSCo Form 8-K dated May 28, 2009	001-03280	4.01
4.41*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.20% First Mortgage Bonds, Series No. 21 due 2020	PSCo Form 8-K dated Nov. 8, 2010	001-03280	4.01
4.42*	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 No. 22 due 2041	PSCo Form 8-K dated Aug. 9, 2011	001-03280	4.01
4.43*	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 No. 23 due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series No. 24 due 2042	PSCo Form 8-K dated Sept. 11, 2012	001-03280	4.01
4.44*	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 No. 25 due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series No. 26 due 2043	PSCo Form 8-K dated March 26, 2013	001-03280	4.01
4.45*	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 No. 27 due 2044	PSCo Form 8-K dated March 10, 2014	001-03280	4.01
4.46*	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 No. 28 due 2025	PSCo Form 8-K dated May 12, 2015	001-03280	4.01
4.47*	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 No. 29 due 2046	PSCo Form 8-K dated June 13, 2016	001-03280	4.01
4.48*	Supplemental Indenture No. 27 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 No. 30 due 2047	PSCo Form 8-K dated June 19, 2017	001-03280	4.01
4.49*	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 No. 31 due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series No. 32 due 2048	PSCo Form 8-K dated June 21, 2018	001-03280	4.01
10.41*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	001-03034	99.02
10.42*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 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, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.03
SPS				
4.50*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	001-03789	99.2
4.51*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 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	001-03034	4.04
4.52*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee	SPS Form 8-K dated Oct. 3, 2006	001-03789	4.01
4.53*	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	001-03789	4.01
4.54*	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 No. 1 due 2041	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.02
4.55*	Sixth Supplemental Indenture dated as of June 1, 2014 between SPS and the Bank of New York Mellon Trust Company, N.A., as successor Trustee	SPS Form 8-K dated June 2, 2014	001-03789	4.03
4.56*	Supplemental Indenture No. 3 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 No. 3 due 2024	SPS Form 8-K dated June 9, 2014	001-03789	4.02
4.57*	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 No. 4 due 2046	SPS Form 8-K dated Aug. 12, 2016	001-03789	4.02

4.58*	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 No. 5 due 2047	SPS Form 8-K dated Aug 9. 2017	001-03789	4.02
4.59*	Supplemental Indenture No. 6 dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating 4.40% First Mortgage Bonds, Series No. 6 due 2048	SPS Form 8-K dated Nov. 5, 2018	001-03789	4.02
10.43*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 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, and Wells Fargo Bank, National Association, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	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	The following materials from Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, (vii) document and entity information, (viii) Schedule I, and (ix) Schedule II.

SCHEDULE I

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

	Year Ended Dec. 31		
	2018	2017	2016
Income			
Equity earnings of subsidiaries	$ 1,393	$ 1,263	$ 1,199
Total income	1,393	1,263	1,199
Expenses and other deductions			
Operating expenses	24	30	22
Other income	(1)	(6)	(3)
Interest charges and financing costs	149	128	116
Total expenses and other deductions	172	152	135
Income before income taxes	1,221	1,111	1,064
Income tax benefit	(40)	(37)	(59)
Net income	$ 1,261	$ 1,148	$ 1,123
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $1, $3 and $(3) respectively	$ 3	$ 4	$ (4)
Derivative instruments, net of tax of $(1), $2 and $2, respectively	(2)	3	4
Other comprehensive income (loss)	1	7	—
Comprehensive income	$ 1,262	$ 1,155	$ 1,123
Weighted average common shares outstanding:			
Basic	511	509	509
Diluted	511	509	509
Earnings per average common share:			
Basic	$ 2.47	$ 2.26	$ 2.21
Diluted	2.47	2.25	2.21

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net cash provided by operating activities	$ 1,210	$ 1,208	$ 817
Investing activities			
Capital contributions to subsidiaries	(809)	(849)	(414)
Investments in the utility money pool	(2,578)	(1,258)	(1,880)
Return of investments in the utility money pool	2,493	1,173	1,880
Net cash used in investing activities	(894)	(934)	(414)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	(295)	715	(516)
Proceeds from issuance of long-term debt	492	—	1,539
Repayment of long-term debt	—	(250)	(704)
Proceeds from issuance of common stock	230	—	—
Repurchase of common stock	(1)	(3)	(32)
Dividends paid	(730)	(721)	(681)
Other	(12)	(14)	(9)
Net cash (used in) provided by financing activities	(316)	(273)	(403)
Net change in cash and cash equivalents	—	1	—
Cash and cash equivalents at beginning of period	1	—	—
Cash and cash equivalents at end of period	$ 1	$ 1	$ —

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2018	2017
Assets		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable from subsidiaries	309	302
Other current assets	1	1
Total current assets	311	304
Investment in subsidiaries	15,965	14,932
Other assets	44	103
Total other assets	16,009	15,035
Total assets	$ 16,320	$ 15,339
Liabilities and Equity		
Current portion of long-term debt	$ —	$ —
Dividends payable	195	183
Short-term debt	488	783
Other current liabilities	10	11
Total current liabilities	693	977
Other liabilities	32	29
Total other liabilities	32	29
Commitments and contingencies		
Capitalization		
Long-term debt	3,373	2,878
Common stockholders' equity	12,222	11,455
Total capitalization	15,595	14,333
Total liabilities and equity	$ 16,320	$ 15,339

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, 2018 and 2017, 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, 2018:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases (a)	Xcel Energy Inc.	$ 11.0	$ —	(d)
Guarantee of loan for Hiawatha Collegiate High School (b)	Xcel Energy Inc.	1.0	—	(d)
Total guarantees issued		12.0	$ —	
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries (c)	Xcel Energy Inc.	$ 51.1	(f)	(e)

(a) The terms of this guarantee expires in 2021 and 2023 when the associated leases expire.
(b) The term of this guarantee expires the earlier of 2024 or full repayment of the loan.
(c) 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.
(d) Nonperformance and/or nonpayment.
(e) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.
(f) 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 and payable with affiliates at Dec. 31:

	2018		2017	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 117	$ —	$ 68	$ —
NSP-Wisconsin	3	—	13	—
PSCo	29	—	69	—
SPS	39	—	26	—
Xcel Energy Services Inc.	96	—	95	—
Xcel Energy Ventures Inc.	13	—	14	—
Other subsidiaries of Xcel Energy Inc.	12	—	17	—
	$ 309	$ —	$ 302	$ —

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $1,097 million, $1,063 million and $923 million for the years ended Dec. 31, 2018, 2017 and 2016, 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, 2018
Loan outstanding at period end	$ —
Average loan outstanding	59
Maximum loan outstanding	172
Weighted average interest rate, computed on a daily basis	2.22%
Weighted average interest rate at end of period	N/A
Money pool interest income	$ 0.3

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Loan outstanding at period end	$ —	$ 85	$ —
Average loan outstanding	71	38	66
Maximum loan outstanding	243	226	211
Weighted average interest rate, computed on a daily basis	1.95%	1.13%	0.69%
Weighted average interest rate at end of period	N/A	1.18	N/A
Money pool interest income	$ 1.4	$ 0.4	$ 0.5

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)	2018	2017	2016	2018	2017	2016
Balance at Jan. 1	$ 52	$ 51	$ 52	$ 77	$ 58	$ 28
Additions Charged to Costs and Expenses	42	39	39	7	9	3
Additions Charged to Other Accounts	11	10	11	— (a)	22 (a)	35 (a)
Deductions from Reserves	(50)	(48)	(51)	(5) (b)	(12) (b)	(8) (b)
Balance at Dec. 31	$ 55	$ 52	$ 51	$ 79	$ 77	$ 58

(a) The 2016 - 2017 changes are the accrual of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability; the 2017 change includes $14 million expense related to the revaluation of federal benefit as a result of the TCJA.
(b) Primarily the reductions to valuation allowances for North Dakota ITC carryforwards, net of federal benefit, primarily due to a consolidated adjustment to the regulatory liability accrual referenced above; the 2017 change includes $4 million of reduced expense related to the revaluation of federal benefit as a result of TCJA.

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. 22, 2019	By:	/s/ ROBERT C. FRENZEL
		Robert C. Frenzel
		Executive Vice President, Chief Financial Officer
		(Principal 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/ BEN FOWKE Ben Fowke	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
	/s/ ROBERT C. FRENZEL Robert C. Frenzel	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
*	Richard K. Davis	Director
*	Richard T. O'Brien	Director
*	David K. Owens	Director
*	Christopher J. Policinski	Director
*	James Prokopanko	Director
*	A. Patricia Sampson	Director
*	James J. Sheppard	Director
*	David A. Westerlund	Director
*	Kim Williams	Director
*	Timothy V. Wolf	Director
*	Daniel Yohannes	Director
*By:	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Attorney-in-Fact

Shareholder Information

Headquarters
414 Nicollet Mall, Minneapolis, MN 55401

Website
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, Corporate Responsibility 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 appears as XcelEngy.

Investor Relations
Website: xcelenergy.com or contact Paul Johnson, Vice President, Investor Relations, at 612.215.4535.

Shareholder Services
Website: 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 2018. It has also filed with the New York Stock Exchange the CEO certification for 2018 required by section 303A.12(a) of the New York Stock Exchange's rules relating to compliance with the New York Stock Exchange's corporate governance listing standards.

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.

The Xcel Energy Board of Directors (from left to right): Tim Wolf, Richard Davis, David Westerlund, Lynn Casey, Chris Policinski, David Owens, Ben Fowke, Kim Williams, Richard O'Brien, Daniel Yohannes, Jim Prokopanko, James Sheppard and Pat Sampson.

Xcel Energy Board of Directors

Lynn Casey [3,4]
Chair, Padilla

Richard K. Davis [2,3]
President and CEO,
Make-A-Wish Foundation

Ben Fowke
Chairman, President and CEO
Xcel Energy Inc.

Richard T. O'Brien [1, 4]
Independent Consultant

David K. Owens [3, 4]
Retired Executive
Edison Electric Institute

Christopher J. Policinski [2]
Lead Independent Director
Retired President and CEO
Land O' Lakes, Inc.

James Prokopanko [2, 4]
Retired President and CEO
The Mosaic Company

A. Patricia Sampson [1, 3]
CEO, President and Owner
The Sampson Group, Inc.

James J. Sheppard [2, 4]
Independent Consultant

David A. Westerlund [1, 2]
Retired Executive Vice President,
Administration and Corporate Secretary
Ball Corporation

Kim Williams [1, 3]
Retired Partner
Wellington Management Company LLP

Timothy V. Wolf [3, 4]
President
Wolf Interests, Inc.

Daniel Yohannes [1, 3]
Former United States Ambassador
to the Organization for Economic
Cooperation and Development

Board Committees:
1. Audit
2. Governance, Compensation and Nominating
3. Finance
4. Operations, Nuclear, Environmental and Safety

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
Wells Fargo Bank, N.A., Corporate Trust Services
150 East 42nd Street, 40th Floor,
New York, NY 10017

Xcel Energy® | RESPONSIBLE BY NATURE®

Schedule Q-4

Reports to the Securities and Exchange Commission

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2018 Form 10-Q
For the Quarterly Period Ended March 31, 2018

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, 2018

or

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

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)

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and 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 and post such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☐
(Do not check if 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 27, 2018
Common Stock, $1 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.

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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. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado, a Colorado corporation (PSCo); and SPS. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. Additional information on Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) is available on various filings with the Securities and Exchange Commission (SEC).

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PART 1 — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended March 31	
	2018	2017
Operating revenues	$ 447,232	$ 460,072
Operating expenses		
Electric fuel and purchased power	253,944	253,685
Operating and maintenance expenses	66,068	76,140
Demand side management expenses	4,158	3,875
Depreciation and amortization	48,416	50,418
Taxes (other than income taxes)	17,590	16,790
Total operating expenses	390,176	400,908
Operating income	57,056	59,164
Other expense, net	(704)	(718)
Allowance for funds used during construction — equity	3,417	2,135
Interest charges and financing costs		
Interest charges — includes other financing costs of $694, and $581, respectively	20,155	22,738
Allowance for funds used during construction — debt	(1,771)	(1,339)
Total interest charges and financing costs	18,384	21,399
Income before income taxes	41,385	39,182
Income taxes	8,286	14,127
Net income	$ 33,099	$ 25,055

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended March 31	
	2018	**2017**
Net income	$ 33,099	$ 25,055
Other comprehensive income		
Pension and retiree medical benefits:		
Amortization of losses included in net periodic benefit cost, net of tax of $5 and $9, respectively	19	15
Derivative instruments:		
Reclassification of losses to net income, net of tax of $3 and $6, respectively	12	9
Other comprehensive income	31	24
Comprehensive income	$ 33,130	$ 25,079

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in thousands)

	Three Months Ended March 31	
	2018	2017
Operating activities		
Net income	$ 33,099	$ 25,055
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	48,479	50,368
Demand side management program amortization	418	418
Deferred income taxes	753	33,079
Amortization of investment tax credits	(13)	(33)
Allowance for equity funds used during construction	(3,417)	(2,135)
Net derivative losses	15	15
Changes in operating assets and liabilities:		
Accounts receivable	(11,369)	(1,486)
Accrued unbilled revenues	12,112	427
Inventories	6,018	7,204
Prepayments and other	1,359	(9,655)
Accounts payable	(11,977)	(7,497)
Net regulatory assets and liabilities	26,974	(2,636)
Other current liabilities	(4,936)	(5,444)
Pension and other employee benefit obligations	(7,880)	(22,278)
Change in other noncurrent assets	511	(306)
Change in other noncurrent liabilities	(218)	372
Net cash provided by operating activities	89,928	65,468
Investing activities		
Utility capital/construction expenditures	(148,911)	(142,559)
Allowance for equity funds used during construction	3,417	2,135
Investments in utility money pool arrangement	(46,000)	—
Repayments from utility money pool arrangement	111,000	—
Net cash used in investing activities	(80,494)	(140,424)
Financing activities		
Proceeds from short-term borrowings, net	10,000	61,000
Borrowings under utility money pool arrangement	1,000	93,000
Repayments under utility money pool arrangement	(1,000)	(93,000)
Capital contributions from parent	360	45,000
Repayment of long-term debt, including reacquisition premiums	—	(18)
Dividends paid to parent	(26,753)	(30,870)
Net cash (used in) provided by financing activities	(16,393)	75,112
Net change in cash and cash equivalents	(6,959)	156
Cash and cash equivalents at beginning of period	10,871	844
Cash and cash equivalents at end of period	$ 3,912	$ 1,000
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (21,194)	$ (14,021)
Cash (paid) received for income taxes, net	(4,034)	9,741
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 36,452	$ 38,096

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	March 31, 2018	Dec. 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 3,912	$ 10,871
Accounts receivable, net	88,537	79,581
Accounts receivable from affiliates	3,500	1,297
Investments in utility money pool arrangement	—	65,000
Accrued unbilled revenues	117,692	129,804
Inventories	34,415	40,433
Regulatory assets	32,265	31,538
Derivative instruments	8,502	15,882
Prepaid taxes	15,199	15,025
Prepayments and other	8,808	10,341
Total current assets	312,830	399,772
Property, plant and equipment, net	5,157,550	5,095,609
Other assets		
Regulatory assets	355,379	362,943
Derivative instruments	18,164	18,954
Other	7,596	11,266
Total other assets	381,139	393,163
Total assets	$ 5,851,519	$ 5,888,544
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 10,000	$ —
Accounts payable	168,786	211,756
Accounts payable to affiliates	12,041	22,577
Regulatory liabilities	81,171	68,835
Taxes accrued	40,199	35,243
Accrued interest	20,271	23,275
Dividends payable	33,255	26,753
Derivative instruments	3,565	3,565
Other	21,889	29,641
Total current liabilities	391,177	421,645
Deferred credits and other liabilities		
Deferred income taxes	576,692	574,906
Regulatory liabilities	787,943	784,564
Asset retirement obligations	28,899	28,524
Derivative instruments	19,057	19,949
Pension and employee benefit obligations	82,354	90,266
Other	4,936	8,386
Total deferred credits and other liabilities	1,499,881	1,506,595
Commitments and contingencies		
Capitalization		
Long-term debt	1,830,223	1,829,941
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at March 31, 2018 and Dec. 31, 2017, respectively	—	—
Additional paid in capital	1,590,242	1,590,242
Retained earnings	541,432	541,588
Accumulated other comprehensive loss	(1,436)	(1,467)
Total common stockholder's equity	2,130,238	2,130,363
Total liabilities and equity	$ 5,851,519	$ 5,888,544

See Notes to Financial Statements

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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 accounting principles generally accepted in the United States of America (GAAP), the financial position of SPS as of March 31, 2018 and Dec. 31, 2017; the results of its operations, including the components of net income and comprehensive income, for the three months ended March 31, 2018 and 2017; and its cash flows for the three months ended March 31, 2018 and 2017. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2018 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, 2017 balance sheet information has been derived from the audited 2017 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2017. 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, 2017, filed with the SEC on Feb. 23, 2018. 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, 2017, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Leases **—** In February 2016, the Financial Accounting Standards Board (FASB) issued *Leases, Topic 842 (Accounting Standards Update (ASU) No. 2016-02)*, which for lessees requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018. SPS has not yet fully determined the impacts of implementation. However, adoption is expected to occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard and proposed in *Targeted Improvements, Topic 842 (Proposed ASU 2018-200)*. As such, agreements entered into prior to Jan. 1, 2019 that are currently considered leases are expected to be recognized on the consolidated balance sheet, including contracts for use of office space, equipment and natural gas storage assets, as well as certain purchased power agreements (PPAs) for natural gas-fueled generating facilities. SPS expects that similar agreements entered into after Dec. 31, 2018 will generally qualify as leases under the new standard.

Recently Adopted

Revenue Recognition **—** In May 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. SPS implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. Other than increased disclosures regarding revenues related to contracts with customers, the implementation did not have a significant impact on SPS' financial statements. For related disclosures, see Note 12.

Classification and Measurement of Financial Instruments **—** In January 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Under the new standard, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are recognized in earnings. SPS implemented the guidance on Jan. 1, 2018 and the implementation did not have a material impact on its financial statements.

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***Presentation of Net Periodic Benefit Cost* —** In March 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. As a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment, and the impacts of adoption will be limited to changes in classification of non-service costs in the statement of income. SPS implemented the new guidance on Jan. 1, 2018, and as a result, $0.7 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the income statement for the three months ended March 31, 2017. Under a practical expedient permitted by the standard, SPS used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Selected Balance Sheet Data

(Thousands of Dollars)	March 31, 2018	Dec. 31, 2017
Accounts receivable, net		
Accounts receivable	$ 94,741	$ 85,929
Less allowance for bad debts	(6,204)	(6,348)
	$ 88,537	$ 79,581

(Thousands of Dollars)	March 31, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$ 26,483	$ 26,218
Fuel	7,932	14,215
	$ 34,415	$ 40,433

(Thousands of Dollars)	March 31, 2018	Dec. 31, 2017
Property, plant and equipment, net		
Electric plant	$ 6,908,735	$ 6,765,371
Construction work in progress	306,920	351,875
Total property, plant and equipment	7,215,655	7,117,246
Less accumulated depreciation	(2,058,105)	(2,021,637)
	$ 5,157,550	$ 5,095,609

4. Income Taxes

Except to the extent noted below, Note 6 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

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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. The following reconciles such differences:

	Three Months ended March 31	
	2018	**2017**
Federal statutory rate	21.0%	35.0%
State tax, net of federal tax effect	2.4	2.1
Increases (decreases) in tax from:		
Regulatory differences - ARAM [(a)]	(4.1)	—
Regulatory differences - ARAM deferral [(b)]	2.9	—
Regulatory differences - other utility plant items	(1.5)	(1.0)
Other tax credits, net of federal income tax expense	(0.7)	(0.5)
Other, net	—	0.5
Effective income tax rate	20.0%	36.1%

(a) The average rate assumption method (ARAM); a method to flow back excess deferred taxes to customers.

(b) As we receive further clarity or direction from our commissions regarding the flow back to customers of excess deferred taxes resulting from the TCJA, the ARAM deferral may decrease during the year, which would result in a reduction to tax expense with a correlating reduction to revenue.

Federal Audits — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2011	December 2018
2012 - 2013	October 2018
2014	September 2018
2015	September 2019
2016	September 2020

In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback and in 2015 the IRS forwarded the issue to the Office of Appeals ("Appeals"). In 2017 Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. SPS did not accrue any income tax benefit related to this adjustment. As of March 31, 2018, the case has been forwarded to the Joint Committee on Taxation.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). After evaluating the proposed adjustment Xcel Energy filed a protest with the IRS. Xcel Energy anticipates the issue will be forwarded to Appeals. As of March 31, 2018, 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 uncertain.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of March 31, 2018, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently 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 the 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 of cash to the taxing authority to an earlier period.

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A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 2.4	$ 2.3
Unrecognized tax benefit — Temporary tax positions	2.0	2.0
Total unrecognized tax benefit	$ 4.4	$ 4.3

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (5.9)	$ (5.9)

It is reasonably possible that SPS' amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and audit resumes and state audits resume. As the IRS Appeals progresses, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $2 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at March 31, 2018, and Dec. 31, 2017 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2018 or Dec. 31, 2017.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 10 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

Tax Reform — Regulatory Proceedings

The specific impacts of the Tax Cuts and Jobs Act (TCJA) on customer rates are subject to regulatory approval. Each of the states in Xcel Energy's service areas, including Texas and New Mexico, have opened dockets to address the impacts of the TCJA. SPS has made filings and is working with various stakeholders in its jurisdictions to determine the appropriate treatment for the TCJA.

In January 2018, the Public Utility Commission of Texas (PUCT) issued an order requiring utilities to apply deferred accounting for the impacts of the TCJA. In February 2018, SPS filed with the PUCT supplemental testimony, which indicated that the TCJA would reduce revenue requirements by approximately $32 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending Texas electric rate case, as discussed below.

In February 2018, SPS filed with the New Mexico Public Regulation Commission (NMPRC) a preliminary quantification of the impacts of the TCJA on its ongoing New Mexico 2017 electric rate case, which indicated that the TCJA would reduce revenue requirements by approximately $11 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending New Mexico electric rate case, as discussed below.

Federal Energy Regulatory Commission (FERC) Formula Rates — The FERC has not yet issued guidance on how or when electric utilities should reflect the impacts of the TCJA in FERC jurisdictional wholesale rates. The FERC issued a Notice of Inquiry (NOI) in March 2018 seeking comments on how to reflect the TCJA impacts in wholesale rates, in particular changes to accumulated deferred income taxes and bonus depreciation. Comments for the NOI are due in May 2018. However, FERC-approved formula rates for wholesale customers are generally adjusted on an annual basis for certain changes in rate base and actual operating expenses, including income taxes. As a result, these revenues would be subject to an automatic reduction for the effect of the TCJA corporate tax rate change through the annual true-up process, absent specific FERC action.

As a portion of the TCJA tax rate change largely offsets a depreciation rate change that was effective Jan. 1, 2018 in its wholesale production rates, SPS has notified FERC that it will continue to charge production rates established in 2017, subject to refund. SPS' wholesale transmission rates continue to be calculated at the pre-TCJA corporate tax rate, subject to true-up in 2019.

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Pending Regulatory Proceedings — PUCT

Texas 2017 Electric Rate Case — In 2017, SPS filed a $55 million, or 5.8 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the PUCT. The request was based on a historic test year (HTY) ended June 30, 2017, a requested return on equity (ROE) of 10.25 percent, an electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent.

The following table summarizes SPS' rate increase request:

Revenue Request (Millions of Dollars)		
Incremental revenue request	$	69
Transmission Cost Recovery Factor (TCRF) rider conversion to base rates [a]		(14)
Net revenue increase request	$	55

[a] The roll-in of the TCRF rider revenue into base rates will not have an impact on customer bills or revenue as these costs are already being recovered through the rider. SPS can request another TCRF rider after the conclusion of this rate case to recover transmission investments subsequent to June 30, 2017.

Key dates in the revised procedural schedule are as follows:

- PUCT Staff direct testimony — May 2, 2018;
- PUCT Staff and intervenors' cross-rebuttal testimony — May 14, 2018;
- SPS' rebuttal testimony — May 23, 2018; and
- Hearings — June 4 - 14, 2018.

As discussed above, the PUCT has opened a docket on the impact of the TCJA, which may have an impact on this rate case. In February 2018, SPS filed supplemental testimony with the PUCT, which indicated that TCJA would reduce revenue requirements by approximately $32 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The final rates are expected to be effective retroactive to Jan. 23, 2018 through a customer surcharge. A PUCT decision is expected in the fourth quarter of 2018.

Appeal of the Texas 2015 Electric Rate Case Decision — In 2014, SPS had requested an overall retail electric revenue rate increase of $42 million. In 2015, the PUCT approved an overall rate decrease of approximately $4 million, net of rate case expenses. In April 2016, SPS filed an appeal with the Texas State District Court (District Court) challenging the PUCT's order that had denied SPS' request for rehearing on certain items in SPS' Texas 2015 electric rate case related to capital structure, incentive compensation and wholesale load reductions. In 2017, the District Court denied SPS' appeal, and SPS appealed the District Court's decision to the Court of Appeals. A decision is pending.

Pending Regulatory Proceeding — NMPRC

New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $43 million. The request is based on a HTY ended June 30, 2017, a ROE of 10.25 percent, an equity ratio of 53.97 percent and a rate base of approximately $885 million, including rate base additions through Nov. 30, 2017. This rate case also takes into account the decline in sales of 380 megawatts (MW) in 2017 from certain wholesale customers and seeks to adjust the life of SPS' Tolk power plant (Unit 1 from 2042 to 2032 and Unit 2 from 2045 to 2032).

In February 2018, SPS filed supplemental information, which indicated that the TCJA would reduce revenue requirements by approximately $11 million. In addition, SPS requested an increase in the equity ratio of 58 percent and an adjustment to regional transmission revenue for the impacts of TCJA.

On April 13, 2018, the NMPRC Staff, the New Mexico Attorney General (NMAG), and several other parties filed testimony. The recommended ROE's ranged from 9.0 percent to of 9.21 percent, and the recommended equity ratios were 51.0 percent to 53.97 percent.

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The following table summarizes certain parties' recommendations from SPS' request:

Millions of Dollars	NMPRC Staff Testimony	NMAG Testimony
SPS request	$ 43	$ 43
Reduction to request for the impact of the TCJA	(11)	(11)
SPS request, including the impact of the TCJA	32	32
ROE (9.0 percent and 9.21 percent, respectively)	(4)	(6)
Capital structure (52.0 percent and 53.97 percent, respectively)	(7)	(3)
Accelerated depreciation (Tolk plant)	(3)	(3)
Disallow rate case expenses	(2)	(3)
Regional transmission revenue (adjustment for the impact of the TCJA)	—	(3)
Post test year plant (estimated numbers were updated to actual)	(1)	(2)
Other, net	(4)	(5)
Recommended rate increase	$ 11	$ 7

Key dates in the procedural schedule are as follows:

- SPS' rebuttal testimony — May 2, 2018; and
- Hearings — May 15 - 25, 2018.

SPS anticipates a decision and implementation of final rates in the second half of 2018.

Appeal of the New Mexico 2016 Electric Rate Case Dismissal — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $41 million, representing a total revenue increase of approximately 10.9 percent. The rate filing was based on a requested ROE of 10.1 percent, an equity ratio of 53.97 percent, an electric rate base of approximately $832 million and a future test year ending June 30, 2018. In 2017, the NMPRC dismissed SPS' rate case. SPS filed a notice of appeal in the New Mexico Supreme Court. A decision is not expected until the second half of 2019.

Pending Regulatory Proceeding — Federal Energy Regulatory Commission (FERC)

Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT) Upgrade Costs — Under the SPP OATT, costs of participant-funded, or "sponsored," transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately $13 million for these charges. SPP is also billing SPS ongoing charges of approximately $0.5 million per month. SPS is currently seeking recovery of these SPP charges in its pending Texas and New Mexico base rate cases.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC denied SPS' complaint. SPS sought rehearing in April 2018, which is pending FERC action. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5 above, the circumstances set forth in Notes 10 and 11 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017, appropriately represent, in all material respects, the current status of commitments and contingent liabilities and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

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PPAs

Under certain PPAs, SPS purchases power from independent power producing entities that own natural gas fueled power plants for which SPS is required to reimburse natural gas 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 associated independent power producing entity.

SPS had approximately 897 megawatts (MW) of capacity under long-term PPAs as of March 31, 2018 and Dec. 31, 2017, with entities that have been determined to be variable interest entities. SPS has 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. These agreements have expiration dates through 2041.

Environmental Contingencies

Manufactured Gas Plant (MGP), Landfill or Disposal Sites — SPS is currently involved in investigating and/or remediating an MGP, landfill or other disposal site. SPS has identified one site where contamination is present and where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities that are underway. SPS anticipates that the investigation or remediation activities will continue through at least 2018. SPS has accrued $0.1 million for the site as of March 31, 2018 and Dec. 31, 2017, respectively. There may be insurance recovery and/or recovery from other potentially responsible parties that will offset any costs incurred. SPS anticipates that any amounts spent will be fully recovered from customers.

Legal Contingencies

SPS is involved in various litigation matters that are being defended and handled 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 such losses that are 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, arising from such current proceedings would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

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, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	—	—
Average amount outstanding	—	13
Maximum amount outstanding	1	100
Weighted average interest rate, computed on a daily basis	1.64%	1.12%
Weighted average interest rate at period end	N/A	N/A

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Commercial Paper **—** SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool. Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 400	$ 400
Amount outstanding at period end	10	—
Average amount outstanding	4	69
Maximum amount outstanding	28	176
Weighted average interest rate, computed on a daily basis	1.86%	1.13%
Weighted average interest rate at period end	2.25	N/A

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. As of March 31, 2018 and Dec. 31, 2017, there were $2 million and $3 million, respectively, 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.

As of March 31, 2018, SPS had the following committed credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 400	$ 12	$ 388

(a) This credit facility expires in June 2021.
(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 facility. SPS had no direct advances on the credit facility outstanding as of March 31, 2018 and Dec. 31, 2017.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain 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. The three levels in the hierarchy are as follows:

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 the following:

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 extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term 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 financial transmission rights (FTRs), purchased from 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. The valuation process for FTRs utilizes the cleared prices for each FTR for the most recent auction.

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 transparency in the auction process, 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, the limited transparency associated with the valuation 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, 2018, accumulated other comprehensive losses 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' risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up 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.

The following table details the gross notional amounts of commodity FTRs as of March 31, 2018 and Dec. 31, 2017:

(Amounts in Thousands) [a]	March 31, 2018	Dec. 31, 2017
Megawatt hours of electricity	6,386	4,251

[a] Amounts are not reflective of net positions in the underlying commodities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were immaterial for the three months ended March 31, 2018 and 2017, respectively.

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During the three months ended March 31, 2018 and 2017, changes in the fair value of FTRs resulted in pre-tax net gains of $0.3 million and $2.0 million, respectively, and were recognized 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 $0.5 million and gains of $1.2 million were recognized for the three months ended March 31, 2018 and 2017, respectively, 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, 2018 and 2017. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of the 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. Given this assessment, as well as an assessment of the impact of SPS' own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

SPS employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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. As of March 31, 2018, two of SPS' most significant counterparties for these activities, comprising $13.2 million or 28 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Six of the most significant counterparties, comprising $9.9 million or 21 percent of this credit exposure, were not rated by Standard & Poor's, Moody's or Fitch Ratings, but based on SPS' internal analysis, had credit quality consistent with investment grade. The one remaining significant counterparty, comprising $0.9 million or 2 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external analysis. All nine of these significant counterparties are municipal or cooperative electric entities or other utilities.

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Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis as of March 31, 2018:

	March 31, 2018					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 6,801	$ 6,801	$ (1,458)	$ 5,343
Total current derivative assets	$ —	$ —	$ 6,801	$ 6,801	$ (1,458)	5,343
PPAs [a]						3,159
Current derivative instruments						$ 8,502
Noncurrent derivative assets						
PPAs [a]						$ 18,164
Noncurrent derivative instruments						$ 18,164
Current derivative liabilities						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 1,458	$ 1,458	$ (1,458)	$ —
Total current derivative liabilities	$ —	$ —	$ 1,458	$ 1,458	$ (1,458)	—
PPAs [a]						3,565
Current derivative instruments						$ 3,565
Noncurrent derivative liabilities						
PPAs [a]						$ 19,057
Noncurrent derivative instruments						$ 19,057

(a) 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.

(b) SPS nets derivative instruments and related collateral in its balance sheet 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, 2018. At March 31, 2018, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis as of Dec. 31, 2017:

	Dec. 31, 2017					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 14,717	$ 14,717	$ (1,994)	$ 12,723
Total current derivative assets	$ —	$ —	$ 14,717	$ 14,717	$ (1,994)	12,723
PPAs [(a)]						3,159
Current derivative instruments						$ 15,882
Noncurrent derivative assets						
PPAs [(a)]						$ 18,954
Noncurrent derivative instruments						$ 18,954
Current derivative liabilities						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 1,994	$ 1,994	$ (1,994)	$ —
Total current derivative liabilities	$ —	$ —	$ 1,994	$ 1,994	$ (1,994)	—
PPAs [(a)]						3,565
Current derivative instruments						$ 3,565
Noncurrent derivative liabilities						
PPAs [(a)]						$ 19,949
Noncurrent derivative instruments						$ 19,949

(a) 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.

(b) SPS nets derivative instruments and related collateral in its balance sheet 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, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
(Thousands of Dollars)	2018	2017
Balance at Jan. 1	$ 12,723	$ 1,955
Purchases	680	3,511
Settlements	(10,439)	(16,400)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	2,379	12,126
Balance at March 31	$ 5,343	$ 1,192

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, 2018 and 2017.

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Fair Value of Long-Term Debt

As of March 31, 2018 and Dec. 31, 2017, other financial instruments for which the carrying amount did not equal fair value were as follows:

	March 31, 2018		Dec. 31, 2017	
(Thousands of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 1,830,223	$ 1,901,350	$ 1,829,941	$ 2,001,992

The fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of March 31, 2018 and Dec. 31, 2017, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

9. Other (Expense), Net

Other (expense), net consisted of the following:

	Three Months Ended March 31	
(Thousands of Dollars)	**2018**	**2017**
Other nonoperating income	$ 2	$ —
Benefits non-service cost	(636)	(749)
Interest (expense) income	(58)	45
Insurance policy expense	(12)	(12)
Other nonoperating expense	—	(2)
Other (expense), net	$ (704)	$ (718)

10. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended March 31			
	2018	**2017**	**2018**	**2017**
(Thousands of Dollars)	**Pension Benefits**		**Postretirement Health Care Benefits**	
Service cost	$ 2,430	$ 2,440	$ 279	$ 219
Interest cost [(a)]	4,603	4,928	410	415
Expected return on plan assets [(a)]	(7,082)	(6,971)	(615)	(589)
Amortization of prior service credit [(a)]	(35)	—	(101)	(100)
Amortization of net loss (gain) [(a)]	3,517	3,245	(113)	(155)
Net periodic benefit cost (credit)	3,433	3,642	(140)	(210)
Credits not recognized due to the effects of regulation	974	148	—	—
Net benefit cost (credit) recognized for financial reporting	$ 4,407	$ 3,790	$ (140)	$ (210)

(a) The components of net periodic cost other than the service cost component are included in the line item "other income, net" in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2018, contributions of $150 million were made across four of Xcel Energy's pension plans, of which $8.0 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2018.

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11. Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive loss, net of tax, for the three months ended March 31, 2018 and 2017 were as follows:

	Three Months Ended March 31, 2018		
(Thousands of Dollars)	**Gains and Losses on Cash Flow Hedges**	**Defined Benefit and Postretirement Items**	**Total**
Accumulated other comprehensive loss at Jan. 1	$ (776)	$ (691)	$ (1,467)
Losses reclassified from net accumulated other comprehensive loss	12	19	31
Net current period other comprehensive income	12	19	31
Accumulated other comprehensive loss at March 31	$ (764)	$ (672)	$ (1,436)

	Three Months Ended March 31, 2017		
(Thousands of Dollars)	**Gains and Losses on Cash Flow Hedges**	**Defined Benefit and Postretirement Items**	**Total**
Accumulated other comprehensive loss at Jan. 1	$ (678)	$ (612)	$ (1,290)
Losses reclassified from net accumulated other comprehensive loss	9	15	24
Net current period other comprehensive income	9	15	24
Accumulated other comprehensive loss at March 31	$ (669)	$ (597)	$ (1,266)

Reclassifications from accumulated other comprehensive loss for the three months ended March 31, 2018 and 2017 were as follows:

	Amounts Reclassified from Accumulated Other Comprehensive Loss	
(Thousands of Dollars)	**Three Months Ended March 31, 2018**	**Three Months Ended March 31, 2017**
Losses on cash flow hedges:		
Interest rate derivatives	$ 15 [(a)]	$ 15 [(a)]
Total, pre-tax	15	15
Tax benefit	(3)	(6)
Total, net of tax	12	9
Defined benefit pension and postretirement losses:		
Amortization of net loss	24 [(b)]	24 [(b)]
Total, pre-tax	24	24
Tax benefit	(5)	(9)
Total, net of tax	19	15
Total amounts reclassified, net of tax	$ 31	$ 24

[(a)] Included in interest charges.

[(b)] Included in the computation of net periodic pension and postretirement benefit costs. See Note 10 for details regarding these benefit plans.

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12. Revenues

SPS principally generates revenue from the transmission, distribution and sale of electricity to wholesale and retail customers. Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. SPS recognizes revenue in an amount that corresponds directly 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 on a systematic basis 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. Contract terms are generally short-term in nature, and as such SPS does not recognize a separate financing component of its collections from customers. SPS presents its revenues net of any excise or other fiduciary-type taxes or fees.

SPS participates in SPP. SPS recognizes sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales. SPS has various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred.

When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify as alternative revenue programs under GAAP. 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. When certain criteria are met (including collection within 24 months), revenue is recognized equal to the revenue requirement, which may include return on rate base items and incentives. The mechanisms are revised periodically for differences between the total amount collected and the revenue recognized, which may increase or decrease the level of revenue collected from customers. Alternative revenue is recorded on a gross basis and is disclosed separate from revenue from contracts with customers in the period earned.

In the following table, regulated electric revenue is classified by the type of goods/services rendered and market/customer type.

	Three Months Ended	
(Thousands of Dollars)	**March 31, 2018**	**March 31, 2017**
Major product lines		
Revenue from contracts with customers:		
Residential	$ 80,049	$ 79,601
Commercial and industrial (C&I)	195,771	200,957
Other	9,664	9,612
Total retail	285,484	290,170
Wholesale	93,232	91,141
Transmission	55,646	54,178
Other	7,531	1,945
Total revenue from contracts with customers	441,893	437,434
Alternative revenue and other	5,339	22,638
Total revenues	$ 447,232	$ 460,072

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).

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Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on SPS' financial condition, results of operations, and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying unaudited financial statements and the related notes to the financial statements. Due to the seasonality of SPS' electric sales, such interim results are not necessarily an appropriate base from which to project annual results.

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 the TCJA's impact to SPS and its customers, as well as assumptions and other statements 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 securities filings (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2017 and subsequent securities filings, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: 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; business conditions in the energy industry; including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where SPS has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors including the extent and timing of the entry of additional competition in the markets served by SPS; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

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. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from the most directly comparable measure calculated and presented in accordance with GAAP. SPS' management uses non-GAAP measures internally for financial planning and analysis, for reporting of results to the Board of Directors, and when communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our operating 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 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 recovery mechanisms, and as a result, changes in these expenses are offset in operating revenues. Management believes electric margin provides 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 O&M expenses, DSM expenses, depreciation and amortization, and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $33 million for the first quarter of 2018, compared with approximately $25 million for the same period in 2017. The increase in net income was largely due to the timing of operating and maintenance (O&M) expenses, favorable impact of weather and lower interest expense.

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Electric Revenues and Margin

Electric 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. The following tables detail the electric revenues and margin:

	Three Months Ended March 31	
(Millions of Dollars)	**2018**	**2017**
Electric revenues	$ 455	$ 460
Electric fuel and purchased power	(254)	(254)
Electric margin before impact of the TCJA	$ 201	$ 206
Impact of the TCJA (offset as a reduction in income tax expense)	(8)	$ —
Electric margin	$ 193	$ 206

The following tables summarize the components of the changes in electric revenues and electric margin for the three months ended March 31, 2018:

Electric Revenues

(Millions of Dollars)	**2018 vs 2017**
Trading	$ 14
Wholesale transmission revenue	5
Estimated impact of weather	4
Fuel and purchased power cost recovery	(18)
Firm wholesale	(7)
Other, net	(3)
Total decrease in electric revenues before impact of the TCJA	$ (5)
Impact of TCJA (offset as a reduction in income tax expense)	(8)
Total decrease in electric revenues	$ (13)

Electric Margin

(Millions of Dollars)	**2018 vs 2017**
Estimated impact of weather	$ 4
Wholesale transmission revenue, net of costs	3
Firm wholesale	(7)
Other, net	(5)
Total decrease in electric margin before impact of the TCJA	$ (5)
Impact of TCJA (offset as a reduction in income tax expense)	(8)
Total decrease in electric margin	$ (13)

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses decreased $10 million, or 13.2 percent, for the first quarter of 2018. The decrease primarily relates to timing of O&M expenses, including planned maintenance and overhauls at various generation facilities.

Income Taxes — Income tax expense decreased $6 million for the first quarter of 2018 compared with the same period in 2017. The decrease was primarily due to the decrease in the federal tax rate due to the TCJA and an increase in plant-related regulatory differences related to ARAM. These were partially offset by the deferral of the effects of ARAM. The ETR was 20.0 percent for the first quarter of 2018, compared with 36.1 percent for the same period in 2017. The lower ETR in 2018 is primarily due to the items referenced above.

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Public Utility Regulation

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 1 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Lubbock Power & Light's (LP&L's) Request for Participation in Electric Reliability Council of Texas (ERCOT) — In September 2017, LP&L filed its application with the PUCT and proposed to transition a portion of its load to ERCOT no later than June 2021. As a result of LP&L's proposal, approximately $18 million in wholesale transmission revenue would be reallocated to remaining SPS transmission customers at the time of the load transition. In November 2017, SPS and various other parties, including the PUCT Staff, filed direct testimony in response to LP&L's application. SPS proposed an Interconnection Switching Fee to be determined by the PUCT.

In February 2018, SPS, LP&L, the PUCT Staff and various other parties filed a stipulation that provides SPS' customers with an Interconnection Switching Fee of approximately $24 million to compensate them for the transfer of LP&L's load from SPP to ERCOT. Under the settlement, SPS would allocate the Interconnection Switching Fee to its Texas and New Mexico retail and wholesale transmission customers through a bill credit following LP&L's load transition to ERCOT. The PUCT approved the stipulation in March 2018. LP&L has announced its intention to transfer to ERCOT effective June 1, 2021.

Texas State Right of First Refusal (ROFR) Request for Declaratory Order — In February 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility, operating in areas outside of ERCOT, the ROFR to construct new transmission facilities located in the utility's service area. SPP stated that Texas law does not provide a clear statement regarding the ROFR for incumbent utilities and therefore SPP was abiding by the portion of its OATT, which requires competitive solicitation to construct and operate new transmission facilities within areas of Texas' SPP footprint.

In October 2017, the PUCT issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities within its service area. In January 2018, SPS and two other parties filed appeals of the PUCT's order in the Texas State District Court. The appeals have been consolidated and the case is being briefed.

Wind Proposals — In 2017, SPS filed proposals with the NMPRC and the PUCT to build, own and operate 1,000 MW of new wind generation through two wind farms (the Hale wind project in Texas and the Sagamore wind project in New Mexico) for a cost of approximately $1.6 billion. In addition, the proposal includes a purchased power agreement for 230 MW of wind.

In March 2018, the NMPRC approved SPS' request consistent with the terms of SPS' and the parties' modified unanimous settlement. The key terms of the settlement are:

- An investment cap of $1,675 per kilowatt, which is equal to 102.5 percent of the estimated construction costs;
- SPS customers would receive a credit to their bills if actual capacity factors fall below 48 percent;
- SPS customers would receive 100 percent of the federal PTC; and
- SPS will sell the output from the two wind farms into the market and keep the revenue and the grossed-up PTCs during the time the rate case is pending before the wind projects go into base rates. If the market revenue and grossed up PTC value exceeds the estimated revenue requirement, SPS will refund the excess amount to customers as an additional customer protection during the interim period.

In February 2018, SPS and the parties filed an unopposed settlement with the PUCT. The key terms of the settlement are similar to the terms approved by the NMPRC above except that the ratemaking treatment of the market revenues and grossed-up PTCs will be treated in a traditional ratemaking manner and the effective date of the rates in the rate cases placing the wind farms in rates will be 35 days after SPS files the rate cases.

In April 2018, the PUCT requested additional information regarding the settlement. SPS filed a response and the PUCT is scheduled to consider the settlement April 27, 2018.

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Summary of Recent Federal Regulatory Developments

FERC

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, asset transactions and mergers, accounting practices and certain other activities of SPS, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2017. In addition to the matters discussed below, see Note 5 to the financial statements for a discussion of other regulatory matters.

Xcel Energy, which includes SPS, attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and Commodity Futures Trading Commission jurisdictions. Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems. While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations.

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 chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of March 31, 2018, 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 the 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 that are being defended and handled 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 such losses that are 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.

Additional Information

See Note 6 to the financial statements for further discussion of legal claims and environmental proceedings. See Part I Item 2 and Note 5 to the financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

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, 2017, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997 (Exhibit 3.01 to Form 10-Q for the quarter ended Sept. 30, 2017 (file no. 001-03789)).
3.02*	By-Laws of SPS as Amended and Restated on Sept. 26, 2013 (Exhibit 3.02 to Form 10-Q/A for the quarter ended Sept. 30, 2013 (file no. 001-03789)).
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	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from SPS' Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Statements of Income, (ii) the Statements of Comprehensive Income (iii) the Statements of Cash Flows, (iv) the Balance Sheets, (v) Notes to Financial Statements, and (vi) document and entity information.

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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 27, 2018	By:	/s/ JEFFREY S. SAVAGE
		Jeffrey S. Savage Senior Vice President, Controller (Principal Accounting Officer)
		/s/ ROBERT C. FRENZEL
		Robert C. Frenzel Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)

2018 Form 10-Q
For the Quarterly Period
Ended June 30, 2018

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, 2018 or

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

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)

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and 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 and post such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☐
(Do not check if 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 27, 2018
Common Stock, $1 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.

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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. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado, a Colorado corporation (PSCo); and SPS. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. Additional information on Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) is available on various filings with the Securities and Exchange Commission (SEC).

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PART 1 — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Operating revenues	$ 481,338	$ 479,796	$ 928,570	$ 939,868
Operating expenses				
Electric fuel and purchased power	257,642	267,942	511,586	521,627
Operating and maintenance expenses	66,148	69,421	132,216	145,561
Demand side management expenses	4,779	3,691	8,937	7,566
Depreciation and amortization	49,579	46,815	97,995	97,233
Taxes (other than income taxes)	15,629	16,689	33,219	33,479
Total operating expenses	393,777	404,558	783,953	805,466
Operating income	87,561	75,238	144,617	134,402
Other expense, net	(782)	(613)	(1,486)	(1,331)
Allowance for funds used during construction — equity	3,201	1,869	6,618	4,004
Interest charges and financing costs				
Interest charges — includes other financing costs of $702, $581, $1,396, and $1,156, respectively	20,621	21,946	40,776	44,684
Allowance for funds used during construction — debt	(1,532)	(1,128)	(3,303)	(2,467)
Total interest charges and financing costs	19,089	20,818	37,473	42,217
Income before income taxes	70,891	55,676	112,276	94,858
Income taxes	12,440	20,314	20,726	34,441
Net income	$ 58,451	$ 35,362	$ 91,550	$ 60,417

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended June 30,		Six Months Ended June 30	
	2018	2017	2018	2017
Net income	$ 58,451	$ 35,362	$ 91,550	$ 60,417
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $5, $9, $10 and $18, respectively	18	15	37	30
Derivative instruments:				
Reclassification of losses to net income, net of tax of $4, $6, $7 and $12, respectively	12	10	24	19
Other comprehensive income	30	25	61	49
Comprehensive income	$ 58,481	$ 35,387	$ 91,611	$ 60,466

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in thousands)

	Six Months Ended June 30	
	2018	2017
Operating activities		
Net income	$ 91,550	$ 60,417
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	98,128	97,126
Demand side management program amortization	837	837
Deferred income taxes	(2,306)	48,099
Amortization of investment tax credits	(26)	(66)
Allowance for equity funds used during construction	(6,618)	(4,004)
Net derivative losses	31	31
Other, net	(5)	10
Changes in operating assets and liabilities:		
Accounts receivable	(25,351)	(12,210)
Accrued unbilled revenues	2,329	(16,668)
Inventories	7,915	5,411
Prepayments and other	671	7,028
Accounts payable	640	16,799
Net regulatory assets and liabilities	46,163	(3,477)
Other current liabilities	13,937	(2,896)
Pension and other employee benefit obligations	(7,885)	(21,946)
Change in other noncurrent assets	4,397	(373)
Change in other noncurrent liabilities	(458)	(2,351)
Net cash provided by operating activities	223,949	171,767
Investing activities		
Utility capital/construction expenditures	(478,352)	(279,918)
Allowance for equity funds used during construction	6,618	4,004
Investments in utility money pool arrangement	(46,000)	—
Repayments from utility money pool arrangement	111,000	—
Other, net	—	(493)
Net cash used in investing activities	(406,734)	(276,407)
Financing activities		
Proceeds from short-term borrowings, net	132,000	56,000
Borrowings under utility money pool arrangement	180,000	572,000
Repayments under utility money pool arrangement	(80,000)	(511,000)
Capital contributions from parent	360	45,000
Repayment of long-term debt	—	(18)
Dividends paid to parent	(60,008)	(57,585)
Other, net	(31)	—
Net cash provided by financing activities	172,321	104,397
Net change in cash and cash equivalents	(10,464)	(243)
Cash and cash equivalents at beginning of period	10,871	844
Cash and cash equivalents at end of period	$ 407	$ 601
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (36,680)	$ (40,450)
Cash (paid) received for income taxes, net	(7,560)	17,213
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 43,286	$ 34,529

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	June 30, 2018	Dec. 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 407	$ 10,871
Accounts receivable, net	102,379	79,581
Accounts receivable from affiliates	4,764	1,297
Investments in utility money pool arrangement	—	65,000
Accrued unbilled revenues	127,475	129,804
Inventories	32,518	40,433
Regulatory assets	26,093	31,538
Derivative instruments	38,549	15,882
Prepaid taxes	15,710	15,025
Prepayments and other	10,219	10,341
Total current assets	358,114	399,772
Property, plant and equipment, net	5,434,187	5,095,609
Other assets		
Regulatory assets	360,902	362,943
Derivative instruments	17,374	18,954
Other	3,710	11,266
Total other assets	381,986	393,163
Total assets	$ 6,174,287	$ 5,888,544
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 132,000	$ —
Borrowings under utility money pool arrangement	100,000	—
Accounts payable	184,825	211,756
Accounts payable to affiliates	15,036	22,577
Regulatory liabilities	123,303	68,835
Taxes accrued	51,965	35,243
Accrued interest	23,413	23,275
Dividends payable	30,697	26,753
Derivative instruments	3,565	3,565
Other	26,019	29,641
Total current liabilities	690,823	421,645
Deferred credits and other liabilities		
Deferred income taxes	577,492	574,906
Regulatory liabilities	781,917	784,564
Asset retirement obligations	29,279	28,524
Derivative instruments	18,166	19,949
Pension and employee benefit obligations	82,326	90,266
Other	4,630	8,386
Total deferred credits and other liabilities	1,493,810	1,506,595
Commitments and contingencies		
Capitalization		
Long-term debt	1,830,508	1,829,941
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at June 30, 2018 and Dec. 31, 2017, respectively	—	—
Additional paid in capital	1,591,366	1,590,242
Retained earnings	569,186	541,588
Accumulated other comprehensive loss	(1,406)	(1,467)
Total common stockholder's equity	2,159,146	2,130,363
Total liabilities and equity	$ 6,174,287	$ 5,888,544

See Notes to Financial Statements

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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 accounting principles generally accepted in the United States of America (GAAP), the financial position of SPS as of June 30, 2018 and Dec. 31, 2017; the results of its operations, including the components of net income and comprehensive income, for the three and six months ended June 30, 2018 and 2017; and its cash flows for the six months ended June 30, 2018 and 2017. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2018 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, 2017 balance sheet information has been derived from the audited 2017 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2017. 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, 2017, filed with the SEC on Feb. 23, 2018. 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, 2017, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Leases **—** In February 2016, the Financial Accounting Standards Board (FASB) issued *Leases, Topic 842 (Accounting Standards Update (ASU) No. 2016-02)*, which for lessees requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018. SPS has not yet fully determined the impacts of implementation. However, adoption is expected to occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard and proposed in *Targeted Improvements, Topic 842 (Proposed ASU 2018-200)*. On Jan. 1, 2019 agreements considered leases for the use of office space, equipment and natural gas storage assets, as well as certain purchased power agreements (PPAs) for fossil-fueled generating facilities are expected to be recognized on the balance sheet.

Recently Adopted

Revenue Recognition **—** In May 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. SPS implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. Other than increased disclosures regarding revenues related to contracts with customers, the implementation did not have a significant impact on SPS' financial statements. For related disclosures, see Note 12 to the financial statements.

Classification and Measurement of Financial Instruments **—** In January 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Under the new standard, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are recognized in earnings. SPS implemented the guidance on Jan. 1, 2018 and the implementation did not have a material impact on its financial statements.

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Presentation of Net Periodic Benefit Cost — In March 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. As a result of the application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment, and the impacts of adoption will be limited to changes in classification of non-service costs in the statement of income. SPS implemented the new guidance on Jan. 1, 2018, and as a result, $1.5 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the income statement for the six months ended June 30, 2017. Under a practical expedient permitted by the standard, SPS used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Selected Balance Sheet Data

(Thousands of Dollars)	June 30, 2018	Dec. 31, 2017
Accounts receivable, net		
Accounts receivable	$ 107,990	$ 85,929
Less allowance for bad debts	(5,611)	(6,348)
	$ 102,379	$ 79,581

(Thousands of Dollars)	June 30, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$ 25,416	$ 26,218
Fuel	7,102	14,215
	$ 32,518	$ 40,433

(Thousands of Dollars)	June 30, 2018	Dec. 31, 2017
Property, plant and equipment, net		
Electric plant	$ 7,059,344	$ 6,765,371
Construction work in progress	447,945	351,875
Total property, plant and equipment	7,507,289	7,117,246
Less accumulated depreciation	(2,073,102)	(2,021,637)
	$ 5,434,187	$ 5,095,609

4. Income Taxes

Except to the extent noted below, Note 6 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

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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. The following reconciles such differences:

	Six Months Ended June 30	
	2018	2017
Federal statutory rate	21.0%	35.0%
State tax, net of federal tax effect	2.4	2.2
Increases (decreases) in tax from:		
Regulatory differences - ARAM [(a)]	(4.2)	—
Regulatory differences - ARAM [(b)]	1.3	—
Regulatory differences - other utility plant items	(1.4)	(0.8)
Tax credits, net of federal income tax expense	(0.7)	(0.5)
Other, net	0.1	0.4
Effective income tax rate	18.5%	36.3%

(a) The average rate assumption method (ARAM); a method to flow back excess deferred taxes to customers.

(b) As we receive direction from our regulatory commissions regarding the return of excess deferred taxes (to our customers resulting from the Tax Cuts and Jobs Act (TCJA)), the ARAM deferral may decrease during the year, which would result in a reduction to tax expense with a corresponding reduction to revenue.

Federal Audits — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. The statutes of limitations applicable to Xcel Energy's federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2011	December 2018
2012 - 2014	October 2019
2015	September 2019
2016	September 2020

In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback claims and in 2015 the IRS forwarded the issue to the Office of Appeals (Appeals). In 2017 Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. SPS did not accrue any income tax benefit related to this adjustment. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). After evaluating the proposed adjustment Xcel Energy filed a protest with the IRS. As of June 30, 2018 the case has been forwarded to Appeals and 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, 2018, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently 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 the 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 of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	June 30, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 2.5	$ 2.3
Unrecognized tax benefit — Temporary tax positions	1.6	2.0
Total unrecognized tax benefit	$ 4.1	$ 4.3

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The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	June 30, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (6.6)	$ (5.9)

It is reasonably possible that SPS' amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and audit resumes and state audits resume. As the IRS Appeals progresses and the IRS audit resumes, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at June 30, 2018 and Dec. 31, 2017 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 2018 or Dec. 31, 2017.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 10 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 and in Note 5 to the financial statements included in to SPS' Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

Tax Reform — Regulatory Proceedings

The specific impacts of the TCJA on customer rates are subject to regulatory approval. Each of the states in Xcel Energy's service areas, including Texas and New Mexico, have opened dockets to address the impacts of the TCJA.

Texas — In June 2018, SPS, the Public Utility Commission of Texas (PUCT) Staff and various intervenors reached a settlement in the Texas electric rate case which included the impacts of the TCJA. The settlement reflects no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be a 57 percent equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings.

New Mexico — In February 2018, SPS indicated that the TCJA would reduce revenue requirements by approximately $11 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending New Mexico electric rate case.

Pending Regulatory Proceedings — PUCT

Texas 2017 Electric Rate Case — In 2017, SPS filed a $54 million, or 5.8 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the PUCT. The request was based on a historic test year (HTY) ended June 30, 2017, a requested return on equity (ROE) of 10.25 percent, an electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent. The request also reflects the acceleration of depreciation lives for the two generating units at the Tolk Generating Station from 2042 and 2045 to 2032.

In May 2018, SPS filed rebuttal testimony and revised its request to an overall increase in the annual base rate revenue of approximately $32 million, or 5.9 percent, net of the TCJA (approximately $32 million after adjusting for a 58 percent equity ratio) and other adjustments. This request would be equivalent to approximately $17 million after adjusting for the Transmission Cost Recovery Factor (TCRF) rider.

In June 2018, SPS, the PUCT Staff and various intervenors reached a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt.

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The following are key terms:

- The ability to use an equity ratio that reflects SPS' actual capital structure, which SPS has informed the parties it intends to be 57 percent to mitigate the impact of TCJA on credit metrics;
- A 9.5 percent ROE for the calculation of allowance for funds used during construction (AFUDC);
- TCRF rider will remain in effect;
- SPS will accelerate depreciation rates for the Tolk Generating Station Units 1 and 2 by 50 percent of the original request; and
- SPS agrees that it will file its next base rate case no later than Dec. 31, 2019.

A reconciliation of the settlement is as follows:

(Millions of Dollars)		
Original base rate request	$	69
Base rate revenue to be recovered through TCRF		(15)
Net revenue request		54
Adjustment for TCJA and other items		(37)
Requested incremental revenue		17
Unspecified settlement adjustments		(13)
Accelerated depreciation (Tolk plant)		(4)
SPS' net revenue change	$	—

Under the terms of the settlement, the final rates would not change from the current rates. However, SPS would be permitted to surcharge customers for unrecovered TCRF charges that were not billed during the period of Jan. 23, 2018 through June 10, 2018. A PUCT decision is expected in the third quarter of 2018.

Appeal of the Texas 2015 Electric Rate Case Decision — In 2014, SPS had requested an overall retail electric revenue rate increase of $42 million. In 2015, the PUCT approved an overall rate decrease of approximately $4 million, net of rate case expenses. In April 2016, SPS filed an appeal with the Texas State District Court (District Court) challenging the PUCT's order. In 2017, the District Court denied SPS' appeal, and SPS appealed the District Court's decision to the state Court of Appeals for the 7th Circuit. In 2018, the Court of Appeals upheld the District Court's decision on the PUCT's order, rejecting SPS' appeal. As part of the settlement of the 2017 Texas rate case, SPS has agreed to end its appeal.

Pending Regulatory Proceeding — New Mexico Public Regulation Commission (NMPRC)

New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $43 million. The request was based on a HTY ended June 30, 2017, a ROE of 10.25 percent, an equity ratio of 53.97 percent, a 35 percent federal income tax rate and a rate base of approximately $885 million, including rate base additions through Nov. 30, 2017.

In May 2018, SPS reduced its request to $27 million, net of the TCJA (approximately $11 million) and other adjustments, based on a requested ROE of 10.25 percent and an equity ratio of 58.0 percent.

In June 2018, the New Mexico Hearing Examiner issued a recommended decision proposing an increase of $12 million based on a ROE of 9.4 percent and an equity ratio of 53.97 percent. She also denied SPS' requests to shorten depreciation lives related to Tolk Units 1 and 2 and Cunningham Unit 1. The Hearing Examiner rejected intervenor proposals to refund the impacts of the TCJA back to Jan. 1, 2018.

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The following table summarizes certain parties' proposed modifications to SPS' request, SPS' revised request, and the Hearing Examiner's recommendation:

(Millions of Dollars)	NMPRC Staff Testimony	NMAG Testimony	SPS Rebuttal Testimony	Hearing Examiner's Recommendation
SPS request	$ 43	$ 43	$ 43	$ 43
Reduction to request for the impact of the TCJA	(11)	(11)	(11)	(11)
SPS request, including the impact of the TCJA	32	32	32	32
ROE	(4)	(6)	—	(5)
Capital structure	(7)	(3)	—	(3)
Depreciation lives (Tolk and Cunningham plants)	(3)	(3)	—	(3)
Disallow rate case expenses	(2)	(3)	(1)	—
Regional transmission revenue and expense (adjustment for the impact of the TCJA):				
Impact of the TCJA	—	(3)	—	(1)
Aligning costs with transmission plant in rate base	—	—	—	(1)
Post test year plant (updated to actual)	(1)	(2)	(3)	—
Excess generation adjustment	—	(1)	—	(1)
Other, net	(4)	(4)	(1)	(6)
Recommended rate increase	$ 11	$ 7	$ 27	$ 12
ROE	9.0%	9.21%	10.25%	9.4%
Equity ratio	52.0%	53.97%	58.0%	53.97%

SPS anticipates a decision and implementation of final rates in the third quarter of 2018.

Appeal of the New Mexico 2016 Electric Rate Case Dismissal — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $41 million, representing a total revenue increase of approximately 10.9 percent. The rate filing was based on a requested ROE of 10.1 percent, an equity ratio of 53.97 percent, an electric rate base of approximately $832 million and a future test year ending June 30, 2018. In 2017, the NMPRC dismissed SPS' rate case. SPS filed a notice of appeal in the New Mexico Supreme Court. A decision is not expected until the second half of 2019.

Pending Regulatory Proceeding — Federal Energy Regulatory Commission (FERC)

Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT) Upgrade Costs — Under the SPP OATT, costs of participant funded, or "sponsored," transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately $13 million for these charges. SPP is also billing SPS ongoing charges of approximately $0.5 million per month. In November 2017, the FERC denied an SPS request for rehearing. In January 2018, SPS appealed the FERC request to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). SPS has filed to recover the SPP charges as part of the appeal. The appeal is currently pending.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC denied SPS' complaint. SPS sought rehearing in April 2018, and the FERC approved the rehearing request for further consideration on May 7, 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

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6. Commitments and Contingencies

Except to the extent noted below and in Note 5 above, the circumstances set forth in Notes 10 and 11 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 and in Notes 5 and 6 to the financial statements included in SPS' Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018, appropriately represent, in all material respects, the current status of commitments and contingent liabilities and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

PPAs

SPS purchases power from independent power producing entities that own natural gas fueled power plants for which SPS is required to reimburse natural gas 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 associated independent power producing entity.

SPS had approximately 897 Megawatts (MW) of capacity under long-term PPAs as of June 30, 2018 and Dec. 31, 2017, with entities that have been determined to be variable interest entities. SPS has 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. These agreements have various expiration dates through 2041.

Environmental Contingencies

Manufactured Gas Plant (MGP), Landfill or Disposal Sites — SPS is currently involved in investigating and/or remediating an MGP, landfill or other disposal site. SPS has identified one site where contamination is present and where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities. SPS anticipates that the investigation or remediation activities will continue through at least 2018. SPS accrued $0.1 million for the site as of June 30, 2018 and Dec. 31, 2017, respectively. There may be insurance recovery and/or recovery from other potentially responsible parties that will offset any costs incurred. SPS anticipates that any amounts spent will be fully recovered from customers.

Legal Contingencies

SPS is involved in various litigation matters that are being defended and handled 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 such losses that are 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, arising from such current proceedings would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

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 June 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	100	—
Average amount outstanding	24	13
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	1.84%	1.12%
Weighted average interest rate at period end	1.85	N/A

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Commercial Paper — SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool. Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 400	$ 400
Amount outstanding at period end	132	—
Average amount outstanding	32	69
Maximum amount outstanding	140	176
Weighted average interest rate, computed on a daily basis	2.25%	1.13%
Weighted average interest rate at period end	2.29	N/A

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. As of June 30, 2018 and Dec. 31, 2017, there were $2 million and $3 million, respectively, 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.

As of June 30, 2018, SPS had the following committed credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 400	$ 134	$ 266

(a) This credit facility expires in June 2021.
(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 facility. SPS had no direct advances on the credit facility outstanding as of June 30, 2018 and Dec. 31, 2017.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain 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. The three levels in the hierarchy are as follows:

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 the following:

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.

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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 extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term 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 financial transmission rights (FTRs), purchased from 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. The valuation process for FTRs utilizes the cleared prices for each FTR for the most recent auction.

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 transparency in the auction process, 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, the limited transparency associated with the valuation of FTRs is 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 June 30, 2018, accumulated other comprehensive losses 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' risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up 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.

The following table details the gross notional amounts of commodity FTRs as of June 30, 2018 and Dec. 31, 2017:

(Amounts in Thousands) [a]	June 30, 2018	Dec. 31, 2017
Megawatt hours of electricity	12,941	4,251

(a) Amounts are not reflective of net positions in the underlying commodities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were immaterial for each of the three and six months ended June 30, 2018 and 2017.

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During the three and six months ended June 30, 2018, changes in the fair value of FTRs resulted in pre-tax net gains of $13.0 million and $13.4 million, respectively, and were recognized as regulatory assets and liabilities. For the three and six months ended June 30, 2017, changes in the fair value of FTRs resulted in pre-tax net gains of $0.2 million and $2.3 million, respectively, and were recognized 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 of $3.9 million and $3.4 million were recognized for the three and six months ended June 30, 2018, respectively, and were recorded to electric fuel and purchased power. For the three and six months ended June 30, 2017, FTR settlement gains of $1.2 million and $2.4 million, respectively, 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 three and six months ended June 30, 2018 and 2017. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of the 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. Given this assessment, as well as an assessment of the impact of SPS' own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

SPS employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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. As of June 30, 2018, six of SPS' most significant counterparties, comprising $25.7 million or 50 percent of this credit exposure, were not rated by Standard & Poor's, Moody's or Fitch Ratings, but based on SPS' internal analysis, had credit quality consistent with investment grade. The one remaining significant counterparty, comprising $0.2 million or less than 1 percent of this credit exposure, had credit quality less than investment grade, based on ratings from internal analysis. All seven of these significant counterparties are municipal or cooperative electric entities or other utilities.

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Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis as of June 30, 2018:

	June 30, 2018					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 35,897	$ 35,897	$ (508)	$ 35,389
Total current derivative assets	$ —	$ —	$ 35,897	$ 35,897	$ (508)	35,389
PPAs [(a)]						3,160
Current derivative instruments						$ 38,549
Noncurrent derivative assets						
PPAs [(a)]						$ 17,374
Noncurrent derivative instruments						$ 17,374
Current derivative liabilities						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 508	$ 508	$ (508)	$ —
Total current derivative liabilities	$ —	$ —	$ 508	$ 508	$ (508)	—
PPAs [(a)]						3,565
Current derivative instruments						$ 3,565
Noncurrent derivative liabilities						
PPAs [(a)]						$ 18,166
Noncurrent derivative instruments						$ 18,166

(a) 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 is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) SPS nets derivative instruments and related collateral in its balance sheet 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, 2018. At June 30, 2018, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis as of Dec. 31, 2017:

	Dec. 31, 2017					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 14,717	$ 14,717	$ (1,994)	$ 12,723
Total current derivative assets	$ —	$ —	$ 14,717	$ 14,717	$ (1,994)	12,723
PPAs [(a)]						3,159
Current derivative instruments						$ 15,882
Noncurrent derivative assets						
PPAs [(a)]						$ 18,954
Noncurrent derivative instruments						$ 18,954
Current derivative liabilities						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 1,994	$ 1,994	$ (1,994)	$ —
Total current derivative liabilities	$ —	$ —	$ 1,994	$ 1,994	$ (1,994)	—
PPAs [(a)]						3,565
Current derivative instruments						$ 3,565
Noncurrent derivative liabilities						
PPAs [(a)]						$ 19,949
Noncurrent derivative instruments						$ 19,949

(a) 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 is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) SPS nets derivative instruments and related collateral in its balance sheet 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, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,	
(Thousands of Dollars)	2018	2017
Balance at April 1	$ 5,343	$ 1,192
Purchases	18,668	35,822
Settlements	(14,798)	(14,098)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	26,176	5,749
Balance at June 30	$ 35,389	$ 28,665

	Six Months Ended June 30	
(Thousands of Dollars)	2018	2017
Balance at Jan. 1	$ 12,723	$ 1,955
Purchases	19,348	39,333
Settlements	(25,237)	(30,498)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	28,555	17,875
Balance at June 30	$ 35,389	$ 28,665

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, 2018 and 2017.

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Fair Value of Long-Term Debt

As of June 30, 2018 and Dec. 31, 2017, other financial instruments for which the carrying amount did not equal fair value were as follows:

	June 30, 2018		Dec. 31, 2017	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 1,830,508	$ 1,858,497	$ 1,829,941	$ 2,001,992

The fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of June 30, 2018 and Dec. 31, 2017, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

9. Other Expense, Net

Other expense, net consisted of the following:

	Three Months Ended June 30		Six Months Ended June 30	
(Thousands of Dollars)	2018	2017	2018	2017
Interest income	$ 356	$ 147	$ 298	$ 192
Other nonoperating income	1	1	3	—
Other nonoperating expense	—	—	—	(1)
Insurance policy expense	(12)	(12)	(24)	(24)
Benefits non-service cost	(1,127)	(749)	(1,763)	(1,498)
Other expense, net	$ (782)	$ (613)	$ (1,486)	$ (1,331)

10. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2018	2017	2018	2017
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 2,430	$ 2,440	$ 280	$ 219
Interest cost [(a)]	4,602	4,927	411	415
Expected return on plan assets [(a)]	(7,082)	(6,971)	(616)	(589)
Amortization of prior service credit [(a)]	(34)	—	(100)	(100)
Amortization of net loss (gain) [(a)]	3,517	3,245	(113)	(155)
Net periodic benefit cost (credit)	3,433	3,641	(138)	(210)
Credits not recognized due to the effects of regulation	761	574	—	—
Net benefit cost (credit) recognized for financial reporting	$ 4,194	$ 4,215	$ (138)	$ (210)

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	Six Months Ended June 30			
	2018	2017	2018	2017
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 4,860	$ 4,880	$ 559	$ 438
Interest cost [(a)]	9,205	9,855	821	830
Expected return on plan assets [(a)]	(14,164)	(13,942)	(1,231)	(1,178)
Amortization of prior service credit [(a)]	(69)	—	(201)	(200)
Amortization of net loss (gain) [(a)]	7,034	6,490	(226)	(310)
Net periodic benefit cost (credit)	6,866	7,283	(278)	(420)
Credits not recognized due to the effects of regulation	1,735	722	—	—
Net benefit cost (credit) recognized for financial reporting	$ 8,601	$ 8,005	$ (278)	$ (420)

(a) The components of net periodic cost other than the service cost component are included in the line item “other expense, net” in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2018, contributions of $150 million were made across four of Xcel Energy’s pension plans, of which $8.0 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2018.

11. Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive loss, net of tax, for the three and six months ended June 30, 2018 and 2017 were as follows:

	Three Months Ended June 30, 2018		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at April 1	$ (764)	$ (672)	$ (1,436)
Losses reclassified from net accumulated other comprehensive loss	12	18	30
Net current period other comprehensive income	12	18	30
Accumulated other comprehensive loss at June 30	$ (752)	$ (654)	$ (1,406)

	Three Months Ended June 30, 2017		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at April 1	$ (669)	$ (597)	$ (1,266)
Losses reclassified from net accumulated other comprehensive loss	10	15	25
Net current period other comprehensive income	10	15	25
Accumulated other comprehensive loss at June 30	$ (659)	$ (582)	$ (1,241)

	Six Months Ended June 30, 2018		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (776)	$ (691)	$ (1,467)
Losses reclassified from net accumulated other comprehensive loss	24	37	61
Net current period other comprehensive income	24	37	61
Accumulated other comprehensive loss at June 30	$ (752)	$ (654)	$ (1,406)

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(Thousands of Dollars)	Six Months Ended June 30, 2017 Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (678)	$ (612)	$ (1,290)
Losses reclassified from net accumulated other comprehensive loss	19	30	49
Net current period other comprehensive income	19	30	49
Accumulated other comprehensive loss at June 30	$ (659)	$ (582)	$ (1,241)

Reclassifications from accumulated other comprehensive loss for the three and six months ended June 30, 2018 and 2017 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended June 30, 2018	Three Months Ended June 30, 2017
Losses on cash flow hedges:		
Interest rate derivatives	$ 16 [a]	$ 16 [a]
Total, pre-tax	16	16
Tax benefit	(4)	(6)
Total, net of tax	12	10
Defined benefit pension and postretirement losses:		
Amortization of net loss	23 [b]	24 [b]
Total, pre-tax	23	24
Tax benefit	(5)	(9)
Total, net of tax	18	15
Total amounts reclassified, net of tax	$ 30	$ 25

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Losses on cash flow hedges:		
Interest rate derivatives	$ 31 [a]	$ 31 [a]
Total, pre-tax	31	31
Tax benefit	(7)	(12)
Total, net of tax	24	19
Defined benefit pension and postretirement losses:		
Amortization of net loss	47 [b]	48 [b]
Total, pre-tax	47	48
Tax benefit	(10)	(18)
Total, net of tax	37	30
Total amounts reclassified, net of tax	$ 61	$ 49

[a] Included in interest charges.

[b] Included in the computation of net periodic pension and postretirement benefit costs. See Note 10 to the financial statements for details regarding these benefit plans.

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12. Revenues

SPS principally generates revenue from the generation, transmission, distribution and sale of electricity to wholesale and retail customers. Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. SPS recognizes revenue in an amount that corresponds directly 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 on a systematic basis 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. Contract terms are generally short-term in nature, and as such SPS does not recognize a separate financing component of its collections from customers. SPS presents its revenues net of any excise or other fiduciary-type taxes or fees.

SPS participates in SPP. SPS recognizes sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs are also recorded on a net basis in cost of sales. SPS has various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred.

When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify as alternative revenue programs under GAAP. 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. When certain criteria are met (including collection within 24 months), revenue is recognized equal to the revenue requirement, which may include return on rate base items and incentives. The mechanisms are revised periodically for differences between the total amount collected and the revenue recognized, which may increase or decrease the level of revenue collected from customers. Alternative revenue is recorded on a gross basis and is disclosed separate from revenue from contracts with customers in the period earned.

In the following tables, regulated electric revenue is classified by the type of goods/services rendered and market/customer type.

	Three Months Ended	
(Thousands of Dollars)	**June 30, 2018**	**June 30, 2017**
Major product lines		
Revenue from contracts with customers:		
Residential	$ 85,107	$ 84,188
Commercial and industrial (C&I)	200,760	215,805
Other	11,363	12,242
Total retail	297,230	312,235
Wholesale	115,629	101,893
Transmission	58,970	56,394
Other	2,858	2,065
Total revenue from contracts with customers	474,687	472,587
Alternative revenue and other	6,651	7,209
Total revenues	$ 481,338	$ 479,796

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	Six Months Ended	
(Thousands of Dollars)	June 30, 2018	June 30, 2017
Major product lines		
Revenue from contracts with customers:		
Residential	$ 165,156	$ 163,789
C&I	396,531	416,762
Other	21,027	21,854
Total retail	582,714	602,405
Wholesale	208,861	193,034
Transmission	114,616	110,572
Other	10,389	4,010
Total revenue from contracts with customers	916,580	910,021
Alternative revenue and other	11,990	29,847
Total revenues	$ 928,570	$ 939,868

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).

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on SPS' financial condition, results of operations, and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying unaudited financial statements and the related notes to the financial statements. Due to the seasonality of SPS' electric sales, such interim results are not necessarily an appropriate base from which to project annual results.

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 the TCJA's impact to SPS and its customers, as well as assumptions and other statements 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 securities filings (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2017 and subsequent securities filings, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: 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; business conditions in the energy industry; including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where SPS has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors including the extent and timing of the entry of additional competition in the markets served by SPS; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric market; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

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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. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from the most directly comparable measure calculated and presented in accordance with GAAP. SPS' management uses non-GAAP measures internally for financial planning and analysis, for reporting of results to the Board of Directors, and when communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our operating 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 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 recovery mechanisms, and as a result, changes in these expenses are offset in operating revenues. Management believes electric margin provides 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 operating and maintenance (O&M) expenses, demand side management (DSM) expenses, depreciation and amortization, and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $92 million for 2018 year-to-date, compared with approximately $60 million for the same period in 2017. The year-to-date increase was largely due to timing of O&M expenses, the favorable impact of weather, sales growth and lower interest expense.

Electric Revenues and Margin

Electric 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. The following tables detail the electric revenues and margin:

	Six Months Ended June 30	
(Millions of Dollars)	**2018**	**2017**
Electric revenues before impact of the TCJA	$ 950	$ 940
Electric fuel and purchased power	(516)	(522)
Electric margin before impact of the TCJA	$ 434	$ 418
Impact of the TCJA (offset as a reduction in income tax expense)	(17)	—
Electric margin	$ 417	$ 418

The following tables summarize the components of the changes in electric revenues and electric margin for the six months ended June 30, 2018:

Electric Revenues

(Millions of Dollars)	**2018 vs 2017**
Fuel and purchased power cost recovery	$ (53)
Firm wholesale	(12)
Trading	36
Wholesale transmission revenue	17
Estimated impact of weather	11
Other, net	11
Total increase in electric revenues before impact of the TCJA	$ 10
Impact of TCJA (offset as a reduction in income tax expense)	(21)
Total decrease in electric revenues	$ (11)

Electric Margin

(Millions of Dollars)	2018 vs 2017
Firm wholesale	$ (12)
Estimated impact of weather	11
Wholesale transmission revenue, net of costs	7
Other, net	10
Total increase in electric margin before impact of the TCJA	$ 16
Impact of TCJA (offset as a reduction in income tax expense)	(17)
Total decrease in electric margin	$ (1)

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses decreased $13 million, or 9.2 percent, for 2018 year-to-date. The decrease primarily relates to timing of O&M expenses, including planned maintenance and overhauls at various generation facilities.

Income Taxes — Income tax expense decreased $14 million for the first six months of 2018 compared with the same period in 2017. The decrease was primarily driven by a lower federal tax rate due to the TCJA and an increase in plant-related regulatory differences related to ARAM (net of deferrals). The ETR was 18.5 percent for the first six months of 2018, compared with 36.3 percent for the same period in 2017. The lower ETR in 2018 is primarily due to the items referenced above. See Note 4 to the financial statements.

Interest Charges — Interest charges decreased $1 million, or 6.0 percent for the second quarter of 2018, and decreased $4 million, or 8.7 percent, year-to-date. The decrease was related to refinancing at lower interest rates, partially offset by higher debt levels to fund capital investments.

Public Utility Regulation

Except to the extent noted below and in Note 5 in the notes to the financial statements, the circumstances set forth in Public Utility Regulation included in Item 1 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 and in Public Utility Regulation included in Item 2 of SPS' Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Texas State Right of First Refusal (ROFR) Request for Declaratory Order — In February 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility, operating in areas outside of Electric Reliability Council of Texas, the ROFR to construct new transmission facilities located in the utility's service area. SPP stated that Texas law does not provide a clear statement regarding the ROFR for incumbent utilities and therefore SPP was abiding by the portion of its OATT, which requires competitive solicitation to construct and operate new transmission facilities within areas of Texas' SPP footprint.

In October 2017, the PUCT issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities within its service area. In January 2018, SPS and two other parties filed appeals of the PUCT's order in the Texas State District Court. The appeals have been consolidated and the case is being briefed.

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — SPS has received certificates of convenience and necessity for the three segments of the TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV transmission line, which are expected to be in service in the second quarter of 2020. This 345 KV transmission line is part of a larger project which includes an additional 345 KV transmission line from the Hobbs Plant Substation to the China Draw Substation, which was placed in service in May 2018. The estimated total investment for these transmission lines is approximately $402 million.

Wind Proposals — In 2017, SPS filed proposals with the NMPRC and the PUCT to build, own and operate 1,000 MW of new wind generation through two wind farms (the Hale wind project in Texas and the Sagamore wind project in New Mexico) for a cost of approximately $1.6 billion. In addition, the proposal includes a purchased power agreement for 230 MW of wind. SPS' wind proposal was approved by both the NMPRC and the PUCT during 2018.

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Summary of Recent Federal Regulatory Developments

FERC

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, asset transactions and mergers, accounting practices and certain other activities of SPS, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2017 and Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018. In addition to the matters discussed below, see Note 5 to the financial statements for a discussion of other regulatory matters.

Xcel Energy, which includes SPS, attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and Commodity Futures Trading Commission jurisdictions. Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems. While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations.

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 chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of June 30, 2018, 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 the 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.

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Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters that are being defended and handled 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 such losses that are 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.

Additional Information

See Note 6 to the financial statements for further discussion of legal claims and environmental proceedings. See Part I Item 2 and Note 5 to the financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

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, 2017, 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

3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997 (Exhibit 3.01 to Form 10-Q for the quarter ended Sept. 30, 2017 (file no. 001-03789)).
3.02*	By-Laws of SPS as Amended and Restated on Sept. 26, 2013 (Exhibit 3.02 to Form 10-Q/A for the quarter ended Sept. 30, 2013 (file no. 001-03789)).
10.01*	Seventh Amendment dated May 7, 2018 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.01 to Form 10-Q of Xcel Energy for the quarter ended June 30, 2018 (file no. 001-03034)).
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	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from SPS' Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Statements of Income, (ii) the Statements of Comprehensive Income (iii) the Statements of Cash Flows, (iv) the Balance Sheets, (v) Notes to Financial Statements, and (vi) document and entity information.

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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 27, 2018

By: /s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Exhibit 31.01

CERTIFICATION

I, Ben Fowke, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 27, 2018

/s/ BEN FOWKE

Ben Fowke
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

Exhibit 31.02

CERTIFICATION

I, Robert C. Frenzel, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting

Date: July 27, 2018

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Exhibit 32.01

OFFICER CERTIFICATION

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Southwestern Public Service Company (SPS) on Form 10-Q for the quarter ended June 30, 2018, as filed with the SEC on the date hereof (Form 10-Q), each of the undersigned officers of SPS certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of SPS as of the dates and for the periods expressed in the Form 10-Q.

Date: July 27, 2018

/s/ BEN FOWKE
Ben Fowke
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to SPS and will be retained by SPS and furnished to the SEC or its staff upon request.

Exhibit 99.01

SPS Cautionary Factors

The Private Securities Litigation Reform Act provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation, providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements are made in written documents and oral presentations of SPS, Xcel Energy Inc. or any of its other subsidiaries. These statements are based on management's beliefs as well as assumptions and information currently available to management. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause SPS' actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;
- The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;
- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where SPS has a financial interest;
- Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the FERC and similar entities with regulatory oversight;
- Availability of cost or capital such as changes in: interest rates; market perceptions of the utility industry, SPS, Xcel Energy Inc. or any of its other subsidiaries; or security ratings;
- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; cyber incidents; or electric transmission or natural gas pipeline constraints;
- Employee workforce factors, including loss or retirement of key executives, collective-bargaining agreements with union employees, or work stoppages;
- Increased competition in the utility industry or additional competition in the markets served by SPS, Xcel Energy Inc. and its other subsidiaries;
- State and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric market; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Environmental laws and regulations, including legislation and regulations relating to climate change, and the associated cost of compliance;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;
- Social attitudes regarding the utility and power industries;
- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;
- Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;
- Risks associated with implementation of new technologies; and
- Other business or investment considerations that may be disclosed from time to time in SEC filings, including "Risk Factors" in Item 1A of SPS' Form 10-K for the year ended Dec. 31, 2017, or in other publicly disseminated written documents.

SPS undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exhaustive.

2018 Form 10-Q
For the Quarterly Period
Ended September 30, 2018

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, 2018 or

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

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)

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 and 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, 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. 26, 2018**
Common Stock, $1 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.

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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. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado, a Colorado corporation (PSCo); and SPS. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. Additional information on Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) is available on various filings with the Securities and Exchange Commission (SEC).

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PART 1 — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30,	
	2018	2017	2018	2017
Operating revenues	$ 540,063	$ 551,623	$ 1,468,633	$ 1,491,491
Operating expenses				
Electric fuel and purchased power	284,006	294,400	795,592	816,027
Operating and maintenance expenses	71,444	65,540	203,660	211,101
Demand side management expenses	4,590	4,236	13,527	11,802
Depreciation and amortization	52,204	47,548	150,199	144,781
Taxes (other than income taxes)	16,814	16,743	50,033	50,222
Total operating expenses	429,058	428,467	1,213,011	1,233,933
Operating income	111,005	123,156	255,622	257,558
Other expense, net	(1,026)	(464)	(2,512)	(1,795)
Allowance for funds used during construction — equity	5,019	2,453	11,637	6,457
Interest charges and financing costs				
Interest charges — includes other financing costs of $710, $625, $2,106, and $1,781, respectively	21,006	21,444	61,782	66,128
Allowance for funds used during construction — debt	(2,223)	(1,349)	(5,526)	(3,816)
Total interest charges and financing costs	18,783	20,095	56,256	62,312
Income before income taxes	96,215	105,050	208,491	199,908
Income taxes	14,674	37,269	35,400	71,710
Net income	$ 81,541	$ 67,781	$ 173,091	$ 128,198

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2018	2017	2018	2017
Net income	$ 81,541	$ 67,781	$ 173,091	$ 128,198
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $5, $9, $15 and $27, respectively	18	16	55	46
Derivative instruments:				
Reclassification of losses to net income, net of tax of $3, $6, $10 and $18, respectively	13	10	37	29
Other comprehensive income	31	26	92	75
Comprehensive income	$ 81,572	$ 67,807	$ 173,183	$ 128,273

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in thousands)

	Nine Months Ended Sept. 30, 2018	Nine Months Ended Sept. 30, 2017
Operating activities		
Net income	$ 173,091	$ 128,198
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	150,403	144,664
Demand side management program amortization	1,255	1,255
Deferred income taxes	14,395	101,388
Amortization of investment tax credits	(39)	(99)
Allowance for equity funds used during construction	(11,637)	(6,457)
Net derivative losses	47	47
Other, net	(5)	9
Changes in operating assets and liabilities:		
Accounts receivable	(25,096)	(25,134)
Accrued unbilled revenues	9,648	(13,682)
Inventories	7,032	(2,845)
Prepayments and other	641	19,361
Accounts payable	(935)	7,817
Net regulatory assets and liabilities	58,832	24,856
Other current liabilities	12,972	19,748
Pension and other employee benefit obligations	(7,907)	(21,638)
Change in other noncurrent assets	3,546	(1,697)
Change in other noncurrent liabilities	(235)	(18,690)
Net cash provided by operating activities	386,008	357,101
Investing activities		
Utility capital/construction expenditures	(621,641)	(400,957)
Allowance for equity funds used during construction	11,637	6,457
Investments in utility money pool arrangement	(46,000)	—
Repayments from utility money pool arrangement	111,000	—
Other, net	—	(493)
Net cash used in investing activities	(545,004)	(394,993)
Financing activities		
Proceeds from short-term borrowings, net	35,000	(50,000)
Proceeds from issuance of long-term debt, net	—	442,651
Borrowings under utility money pool arrangement	446,000	323,000
Repayments under utility money pool arrangement	(423,000)	(323,000)
Capital contributions from parent	181,484	45,000
Repayment of long-term debt	—	(271,613)
Dividends paid to parent	(90,705)	(82,599)
Other, net	(31)	—
Net cash provided by financing activities	148,748	83,439
Net change in cash and cash equivalents	(10,248)	45,547
Cash and cash equivalents at beginning of period	10,871	844
Cash and cash equivalents at end of period	$ 623	$ 46,391
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (57,924)	$ (58,581)
Cash (paid) received for income taxes, net	(15,251)	37,899
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 54,601	$ 40,861

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	Sept. 30, 2018	Dec. 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 623	$ 10,871
Accounts receivable, net	101,870	79,581
Accounts receivable from affiliates	4,085	1,297
Investments in utility money pool arrangement	—	65,000
Accrued unbilled revenues	120,156	129,804
Inventories	33,401	40,433
Regulatory assets	23,387	31,538
Derivative instruments	28,436	15,882
Prepaid taxes	15,821	15,025
Prepayments and other	10,137	10,341
Total current assets	337,916	399,772
Property, plant and equipment, net	5,539,200	5,095,609
Other assets		
Regulatory assets	366,885	362,943
Derivative instruments	16,584	18,954
Other	4,602	11,266
Total other assets	388,071	393,163
Total assets	$ 6,265,187	$ 5,888,544
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 35,000	$ —
Borrowings under utility money pool arrangement	23,000	—
Accounts payable	191,874	211,756
Accounts payable to affiliates	17,308	22,577
Regulatory liabilities	112,585	68,835
Taxes accrued	53,453	35,243
Accrued interest	20,396	23,275
Dividends payable	40,071	26,753
Derivative instruments	3,565	3,565
Other	25,548	29,641
Total current liabilities	522,800	421,645
Deferred credits and other liabilities		
Deferred income taxes	601,294	574,906
Regulatory liabilities	795,424	784,564
Asset retirement obligations	29,664	28,524
Derivative instruments	17,275	19,949
Pension and employee benefit obligations	82,369	90,266
Other	4,816	8,386
Total deferred credits and other liabilities	1,530,842	1,506,595
Commitments and contingencies		
Capitalization		
Long-term debt	1,830,796	1,829,941
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at Sept. 30, 2018 and Dec. 31, 2017, respectively	—	—
Additional paid in capital	1,771,469	1,590,242
Retained earnings	610,655	541,588
Accumulated other comprehensive loss	(1,375)	(1,467)
Total common stockholder's equity	2,380,749	2,130,363
Total liabilities and equity	$ 6,265,187	$ 5,888,544

See Notes to Financial Statements

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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 accounting principles generally accepted in the United States of America (GAAP), the financial position of SPS as of Sept. 30, 2018 and Dec. 31, 2017; the results of its operations, including the components of net income and comprehensive income, for the three and nine months ended Sept. 30, 2018 and 2017; and its cash flows for the nine months ended Sept. 30, 2018 and 2017. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2018 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, 2017 balance sheet information has been derived from the audited 2017 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2017. 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, 2017, filed with the SEC on Feb. 23, 2018. 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, 2017, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Leases — In February 2016, the Financial Accounting Standards Board (FASB) issued *Leases, Topic 842 (Accounting Standards Update (ASU) No. 2016-02)*, which for lessees requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018. Adoption will occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard and included in *Targeted Improvements, Topic 842* (*ASU No. 2018-11*). On Jan. 1, 2019, agreements historically disclosed as operating leases for the use of real estate, equipment and certain fossil-fueled generating facilities operated under purchased power agreements (PPAs) are expected to be recognized on the consolidated balance sheet. Other than first-time recognition of these types of operating leases on the balance sheet, the implementation is not expected to have a significant impact on SPS' financial statements.

Recently Adopted

Revenue Recognition — In May 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. SPS implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. Other than increased disclosures regarding revenues related to contracts with customers, the implementation did not have a material impact on SPS' financial statements. For related disclosures, see Note 12 to the financial statements.

Classification and Measurement of Financial Instruments — In January 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Under the new standard, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are recognized in earnings. SPS implemented the guidance on Jan. 1, 2018 and the implementation did not have a material impact on its financial statements.

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Presentation of Net Periodic Benefit Cost — In March 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. As a result of the application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment, and the impacts of adoption will be limited to changes in classification of non-service costs in the statement of income. SPS implemented the new guidance on Jan. 1, 2018, and as a result, $0.7 million and $2.2 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the income statement for the three and nine months ended Sept. 30, 2017, respectively. Under a practical expedient permitted by the standard, SPS used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Accounts receivable, net		
Accounts receivable	$ 107,709	$ 85,929
Less allowance for bad debts	(5,839)	(6,348)
	$ 101,870	$ 79,581

(Thousands of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$ 25,380	$ 26,218
Fuel	8,021	14,215
	$ 33,401	$ 40,433

(Thousands of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Property, plant and equipment, net		
Electric plant	$ 7,115,175	$ 6,765,371
Construction work in progress	533,538	351,875
Total property, plant and equipment	7,648,713	7,117,246
Less accumulated depreciation	(2,109,513)	(2,021,637)
	$ 5,539,200	$ 5,095,609

4. Income Taxes

Except to the extent noted below, Note 6 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

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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. The following reconciles such differences:

	Nine Months Ended Sept. 30,	
	2018	2017
Federal statutory rate	21.0%	35.0%
State tax (net of federal tax effect)	2.3	2.3
Increases (decreases) in tax from:		
Regulatory differences - ARAM [(a)]	(4.0)	—
Regulatory differences - ARAM deferral [(b)]	1.7	—
Regulatory differences - reversal of prior quarters' ARAM deferral [(b)]	(0.2)	—
Regulatory differences - other utility plant items	(1.3)	(0.8)
Tax credits (net of federal income tax expense)	(0.7)	(0.7)
Other (net)	(1.8)	0.1
Effective income tax rate	17.0%	35.9%

(a) The average rate assumption method (ARAM); a method to flow back excess deferred taxes to customers.

(b) ARAM has been deferred when regulatory treatment has not been established. As SPS received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

Federal Audits — SPS is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020

In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017 Xcel Energy and the Office of Appeals (Appeals) reached an agreement and the benefit related to the agreed upon portions was recognized. SPS did not accrue any income tax benefit related to this adjustment. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). Xcel Energy filed a protest with the IRS. As of Sept. 30, 2018 the case has been forwarded to Appeals and 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, 2018, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently 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 the 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 of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 2.8	$ 2.3
Unrecognized tax benefit — Temporary tax positions	1.6	2.0
Total unrecognized tax benefit	$ 4.4	$ 4.3

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The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (6.9)	$ (5.9)

It is reasonably possible that SPS' amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and audit resumes and state audits resume. As the IRS Appeals progresses and the IRS audit resumes, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3 million.

Payables for interest related to unrecognized tax benefits were not material and no amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2018 or Dec. 31, 2017.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 10 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 and in Note 5 to the financial statements included in to SPS' Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

Tax Reform — Regulatory Proceedings

The specific impacts of the TCJA on customer rates are subject to regulatory approval. The following details the status of regulatory decisions in each state where Xcel Energy, which includes Texas and New Mexico, operates.

Texas — In June 2018, SPS, the Public Utility Commission of Texas (PUCT) Staff and various intervenors reached a settlement in the Texas electric rate case which included the impacts of the TCJA. The settlement reflects no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be up to a 57 percent equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings. A PUCT decision is expected in the fourth quarter of 2018.

New Mexico — In September 2018, the New Mexico Public Regulation Commission (NMPRC) issued its final order in SPS' 2017 electric rate case, which included a refund of the 2018 impact of the TCJA.

Pending Regulatory Proceedings — PUCT

Texas 2017 Electric Rate Case — In 2017, SPS filed a $54 million, or 5.8 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the PUCT. The request was based on a historic test year (HTY) ended June 30, 2017, a requested return on equity (ROE) of 10.25 percent, an electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent.

In May 2018, SPS filed rebuttal testimony and revised its request to an overall increase in the annual base rate revenue of approximately $32 million, or 5.9 percent, net of the TCJA (after adjusting for a requested 58 percent equity ratio) and other adjustments. This request would be equivalent to approximately $17 million after adjusting for the Transmission Cost Recovery Factor (TCRF) rider.

In June 2018, SPS, the PUCT Staff and various intervenors reached a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt.

The following are key terms:

- The ability to use an equity ratio that reflects SPS' actual capital structure, up to 57 percent;
- A 9.5 percent ROE for the calculation of allowance for funds used during construction (AFUDC);
- TCRF rider will remain in effect;
- SPS will accelerate the depreciable lives of Tolk Units 1 and 2 from 2042 and 2045, respectively, to 2037; and
- SPS agrees that it will file its next base rate case no later than Dec. 31, 2019.

A PUCT decision on the settlement is expected in the fourth quarter of 2018.

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Pending Regulatory Proceeding — New Mexico Public Regulation Commission (NMPRC)

New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $43 million. The request was based on a HTY ended June 30, 2017, a ROE of 10.25 percent, an equity ratio of 53.97 percent, a 35 percent federal income tax rate and a rate base of approximately $885 million, including rate base additions through Nov. 30, 2017.

In May 2018, SPS reduced its request to $27 million, net of the TCJA (approximately $11 million, net of the requested higher equity ratio) and other adjustments, based on a requested ROE of 10.25 percent and an equity ratio of 58.0 percent.

In June 2018, the New Mexico Hearing Examiner issued a recommended decision proposing an increase of $12 million based on a ROE of 9.4 percent and an equity ratio of 53.97 percent. She also denied SPS' requests to shorten depreciation lives related to Tolk Units 1 and 2 and Cunningham Unit 1. The Hearing Examiner rejected intervenor proposals to refund the impacts of the TCJA back to Jan. 1, 2018.

On Sept. 5, 2018, the NMPRC issued its final order resulting in a revenue increase of approximately $8 million, or 2.1 percent, effective Sept. 27, 2018, based on a ROE of 9.1 percent and a 51 percent equity ratio. The NMPRC also ordered a refund of $10 million associated with the TCJA impacts for the retroactive period of Jan. 1, 2018 through Sept. 27, 2018. SPS recorded a regulatory liability of $10 million for the customer refund in the third quarter of 2018.

On Sept. 7, 2018, SPS filed an appeal with the NMSC on the grounds that the NMPRC’s findings are contrary to the factual record and do not result in just and reasonable rates as required by law. In addition, SPS filed a motion for stay with the NMSC to delay the implementation of the retroactive TCJA refund until the NMSC issues its decision on SPS' appeal of the rate case order. SPS considers the refund illegal primarily because it violates the prohibition on retroactive ratemaking and results in rates that are not just and reasonable. On Sept. 26, 2018, the NMSC granted a temporary stay to delay the implementation of the retroactive refund until further order of the Court.

Appeal of the New Mexico 2016 Electric Rate Case Dismissal — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $41 million, representing a total revenue increase of approximately 10.9 percent. The rate filing was based on a requested ROE of 10.1 percent, an equity ratio of 53.97 percent, an electric rate base of approximately $832 million and a future test year ended June 30, 2018. In 2017, the NMPRC dismissed SPS’ rate case. SPS filed a notice of appeal in the NMSC. A decision is not expected until the second half of 2019.

Pending Regulatory Proceeding — Federal Energy Regulatory Commission (FERC)

Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT) Upgrade Costs — Under the SPP OATT, costs of participant funded, or “sponsored,” transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP’s request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately $13 million for these charges. SPP is also billing SPS ongoing charges of approximately $0.5 million per month. 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 these charges was remanded to the FERC. As of September 2018, SPS’ recovery of these charges (from 2008 through 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.

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In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC denied SPS' complaint. SPS sought rehearing in April 2018, and the FERC granted a rehearing for purposes of further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

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. The FERC initially determined the facilities did not qualify as transmission facilities under the SPP OATT. SPP's proposed tariff changes could result in an increase in the annual transmission revenue requirement (ATRR) of $9.5 million per year, with $6 million allocated to SPS' retail customers. The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone. In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. The FERC is expected to take initial action in the fourth quarter of 2018.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5 above, the circumstances set forth in Notes 10, 11 and 12 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 and in Notes 5 and 6 to the financial statements included in SPS' Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, appropriately represent, in all material respects, the current status of commitments and contingent liabilities and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

PPAs

SPS purchases power from independent power producing entities that own natural gas fueled power plants for which SPS is required to reimburse natural gas 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 associated independent power producing entity.

SPS had approximately 967 Megawatts (MW) of capacity under long-term PPAs as of Sept. 30, 2018 and 897 MW as of Dec. 31, 2017, with entities that have been determined to be variable interest entities. SPS has 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. These agreements have various expiration dates through 2041.

Environmental Contingencies

Manufactured Gas Plant (MGP), Landfill or Disposal Sites **—** SPS is currently involved in investigating and/or remediating an MGP, landfill or other disposal site. SPS has identified one site where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities. SPS anticipates that the investigation or remediation activities will continue through at least 2019. SPS accrued $0.1 million for the site as of Sept. 30, 2018 and Dec. 31, 2017, respectively. There may be insurance recovery and/or recovery from other responsible parties that will offset any costs incurred.

Legal Contingencies

SPS is involved in various litigation matters that are being defended and handled 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 such losses that are 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, arising from such current proceedings would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

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7. Borrowings and Other Financing Instruments

Short-Term Borrowings

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 Sept. 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	23	—
Average amount outstanding	76	13
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	1.97%	1.12%
Weighted average interest rate at period end	1.99	N/A

Commercial Paper — SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool. Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 400	$ 400
Amount outstanding at period end	35	—
Average amount outstanding	63	69
Maximum amount outstanding	144	176
Weighted average interest rate, computed on a daily basis	2.25%	1.13%
Weighted average interest rate at period end	2.35	N/A

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. As of Sept. 30, 2018 and Dec. 31, 2017, there were $2 million and $3 million, respectively, 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.

As of Sept. 30, 2018, SPS had the following committed credit facility available (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 400	$ 37	$ 363

(a) This credit facility expires in June 2021.
(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 facility. SPS had no direct advances on the credit facility outstanding as of Sept. 30, 2018 and Dec. 31, 2017.

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8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain 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. The three levels in the hierarchy are as follows:

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 the following:

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 extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term 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 financial transmission rights (FTRs), purchased from 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. The valuation process for FTRs utilizes the cleared prices for each FTR for the most recent auction.

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 transparency in the auction process, 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, the limited transparency associated with the valuation of FTRs is 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.

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As of Sept. 30, 2018, accumulated other comprehensive losses 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' risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up 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.

The following table details the gross notional amounts of commodity FTRs as of Sept. 30, 2018 and Dec. 31, 2017:

(Amounts in Thousands) [(a)]	Sept. 30, 2018	Dec. 31, 2017
Megawatt hours of electricity	8,594	4,251

(a) Amounts are not reflective of net positions in the underlying commodities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were immaterial for each of the three and nine months ended Sept. 30, 2018 and 2017.

During the three and nine months ended Sept. 30, 2018, changes in the fair value of FTRs resulted in pre-tax net losses of $3.3 million and pre-tax net gains of $10.1 million, respectively, and were recognized as regulatory assets and liabilities. For the three and nine months ended Sept. 30, 2017, changes in the fair value of FTRs resulted in pre-tax net losses of $2.5 million and $0.2 million, respectively, and were recognized 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.

There were immaterial FTR settlement losses and $3.4 million of FTR settlement gains recognized for the three and nine months ended Sept. 30, 2018, respectively, and were recorded to electric fuel and purchased power. For the three and nine months ended Sept. 30, 2017, FTR settlement losses of $2.2 million and gains of $0.1 million, respectively, 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 three and nine months ended Sept. 30, 2018 and 2017. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of the 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. Given this assessment, as well as an assessment of the impact of SPS' own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

SPS employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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. As of Sept. 30, 2018, two of SPS' most significant counterparties, comprising $16.9 million or 34 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Five of the most significant counterparties, comprising $10.7 million or 22 percent of this credit exposure, were not rated by these external agencies, but based on SPS's internal analysis, had credit quality consistent with investment grade. All seven of these significant counterparties are municipal or cooperative electric entities or other utilities.

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Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis as of Sept. 30, 2018:

	Sept. 30, 2018					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 25,666	$ 25,666	$ (389)	$ 25,277
Total current derivative assets	$ —	$ —	$ 25,666	$ 25,666	$ (389)	25,277
PPAs [(a)]						3,159
Current derivative instruments						$ 28,436
Noncurrent derivative assets						
PPAs [(a)]						$ 16,584
Noncurrent derivative instruments						$ 16,584
Current derivative liabilities						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 389	$ 389	$ (389)	$ —
Total current derivative liabilities	$ —	$ —	$ 389	$ 389	$ (389)	—
PPAs [(a)]						3,565
Current derivative instruments						$ 3,565
Noncurrent derivative liabilities						
PPAs [(a)]						$ 17,275
Noncurrent derivative instruments						$ 17,275

(a) 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 is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) SPS nets derivative instruments and related collateral in its balance sheet 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, 2018. At Sept. 30, 2018, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis as of Dec. 31, 2017:

	Dec. 31, 2017					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 14,717	$ 14,717	$ (1,994)	$ 12,723
Total current derivative assets	$ —	$ —	$ 14,717	$ 14,717	$ (1,994)	12,723
PPAs [(a)]						3,159
Current derivative instruments						$ 15,882
Noncurrent derivative assets						
PPAs [(a)]						$ 18,954
Noncurrent derivative instruments						$ 18,954
Current derivative liabilities						
Other derivative instruments:						
Electric commodity	$ —	$ —	$ 1,994	$ 1,994	$ (1,994)	$ —
Total current derivative liabilities	$ —	$ —	$ 1,994	$ 1,994	$ (1,994)	—
PPAs [(a)]						3,565
Current derivative instruments						$ 3,565
Noncurrent derivative liabilities						
PPAs [(a)]						$ 19,949
Noncurrent derivative instruments						$ 19,949

(a) 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 is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) SPS nets derivative instruments and related collateral in its balance sheet 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, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2018 and 2017:

	Three Months Ended Sept. 30,	
(Thousands of Dollars)	2018	2017
Balance at July 1	$ 35,389	$ 28,665
Purchases	3,169	43
Settlements	(10,068)	(9,939)
Net transactions recorded during the period:		
Net (losses) gains recognized as regulatory assets and liabilities	(3,213)	1,669
Balance at Sept. 30	$ 25,277	$ 20,438

	Nine Months Ended Sept. 30,	
(Thousands of Dollars)	2018	2017
Balance at Jan. 1	$ 12,723	$ 1,955
Purchases	22,517	39,376
Settlements	(35,305)	(40,437)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	25,342	19,544
Balance at Sept. 30	$ 25,277	$ 20,438

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, 2018 and 2017.

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Fair Value of Long-Term Debt

As of Sept. 30, 2018 and Dec. 31, 2017, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Sept. 30, 2018		Dec. 31, 2017	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 1,830,796	$ 1,832,158	$ 1,829,941	$ 2,001,992

The fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Sept. 30, 2018 and Dec. 31, 2017, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

9. Other Expense, Net

Other expense, net consisted of the following:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30,	
(Thousands of Dollars)	2018	2017	2018	2017
Interest income	$ 473	$ 296	$ 771	$ 488
Other nonoperating income	—	1	2	—
Other nonoperating expense	(1)	—	—	—
Insurance policy expense	(11)	(12)	(35)	(36)
Benefits non-service cost	(1,487)	(749)	(3,250)	(2,247)
Other expense, net	$ (1,026)	$ (464)	$ (2,512)	$ (1,795)

10. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2018	2017	2018	2017
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 2,429	$ 2,439	$ 280	$ 219
Interest cost [(a)]	4,603	4,928	410	415
Expected return on plan assets [(a)]	(7,082)	(6,971)	(615)	(589)
Amortization of prior service credit [(a)]	(34)	—	(101)	(100)
Amortization of net loss (gain) [(a)]	3,517	3,245	(114)	(155)
Net periodic benefit cost (credit)	3,433	3,641	(140)	(210)
(Costs) credits not recognized due to the effects of regulation	(468)	553	—	—
Net benefit cost (credit) recognized for financial reporting	$ 2,965	$ 4,194	$ (140)	$ (210)

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	Nine Months Ended Sept. 30			
	2018	2017	2018	2017
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 7,289	$ 7,319	$ 839	$ 657
Interest cost [(a)]	13,808	14,783	1,231	1,245
Expected return on plan assets [(a)]	(21,246)	(20,913)	(1,846)	(1,767)
Amortization of prior service credit [(a)]	(103)	—	(302)	(300)
Amortization of net loss (gain) [(a)]	10,551	9,735	(340)	(465)
Net periodic benefit cost (credit)	10,299	10,924	(418)	(630)
Credits not recognized due to the effects of regulation	1,267	1,275	—	—
Net benefit cost (credit) recognized for financial reporting	$ 11,566	$ 12,199	$ (418)	$ (630)

[(a)] The components of net periodic cost other than the service cost component are included in the line item "other expense, net" in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2018, contributions of $150 million were made across four of Xcel Energy's pension plans, of which $8.0 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2018.

11. Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive loss, net of tax, for the three and nine months ended Sept. 30, 2018 and 2017 were as follows:

	Three Months Ended Sept. 30, 2018		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at July 1	$ (752)	$ (654)	$ (1,406)
Losses reclassified from net accumulated other comprehensive loss	13	18	31
Net current period other comprehensive income	13	18	31
Accumulated other comprehensive loss at Sept. 30	$ (739)	$ (636)	$ (1,375)

	Three Months Ended Sept. 30, 2017		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at July 1	$ (659)	$ (582)	$ (1,241)
Losses reclassified from net accumulated other comprehensive loss	10	16	26
Net current period other comprehensive income	10	16	26
Accumulated other comprehensive loss at Sept. 30	$ (649)	$ (566)	$ (1,215)

	Nine Months Ended Sept. 30, 2018		
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (776)	$ (691)	$ (1,467)
Losses reclassified from net accumulated other comprehensive loss	37	55	92
Net current period other comprehensive income	37	55	92
Accumulated other comprehensive loss at Sept. 30	$ (739)	$ (636)	$ (1,375)

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(Thousands of Dollars)	Nine Months Ended Sept. 30, 2017 Gains and Losses on Cash Flow Hedges	Defined Benefit and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (678)	$ (612)	$ (1,290)
Losses reclassified from net accumulated other comprehensive loss	29	46	75
Net current period other comprehensive income	29	46	75
Accumulated other comprehensive loss at Sept. 30	$ (649)	$ (566)	$ (1,215)

Reclassifications from accumulated other comprehensive loss for the three and nine months ended Sept. 30, 2018 and 2017 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended Sept. 30, 2018	Three Months Ended Sept. 30, 2017
Losses on cash flow hedges:		
Interest rate derivatives	$ 16 [(a)]	$ 16 [(a)]
Total, pre-tax	16	16
Tax benefit	(3)	(6)
Total, net of tax	13	10
Defined benefit pension and postretirement losses:		
Amortization of net loss	23 [(b)]	24 [(b)]
Total, pre-tax	23	24
Tax benefit	(5)	(8)
Total, net of tax	18	16
Total amounts reclassified, net of tax	$ 31	$ 26

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Nine Months Ended Sept. 30, 2018	Nine Months Ended Sept. 30, 2017
Losses on cash flow hedges:		
Interest rate derivatives	$ 47 [(a)]	$ 47 [(a)]
Total, pre-tax	47	47
Tax benefit	(10)	(18)
Total, net of tax	37	29
Defined benefit pension and postretirement losses:		
Amortization of net loss	70 [(b)]	72 [(b)]
Total, pre-tax	70	72
Tax benefit	(15)	(26)
Total, net of tax	55	46
Total amounts reclassified, net of tax	$ 92	$ 75

[(a)] Included in interest charges.

[(b)] Included in the computation of net periodic pension and postretirement benefit costs. See Note 10 to the financial statements for details regarding these benefit plans.

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12. Revenues

SPS principally generates revenue from the generation, transmission, distribution and sale of electricity to wholesale and retail customers. Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. SPS recognizes revenue in an amount that corresponds directly 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 on a systematic basis 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. Contract terms are generally short-term in nature, and as such SPS does not recognize a separate financing component of its collections from customers. SPS presents its revenues net of any excise or other fiduciary-type taxes or fees.

SPS participates in SPP. SPS recognizes sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs are also recorded on a net basis in cost of sales. SPS has various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred.

When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify as alternative revenue programs under GAAP. 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. When certain criteria are met (including collection within 24 months), revenue is recognized equal to the revenue requirement, which may include return on rate base items and incentives. The mechanisms are revised periodically for differences between the total amount collected and the revenue recognized, which may increase or decrease the level of revenue collected from customers. Alternative revenue is recorded on a gross basis and is disclosed separate from revenue from contracts with customers in the period earned.

In the following tables, regulated electric revenue is classified by the type of goods/services rendered and market/customer type.

	Three Months Ended	
(Thousands of Dollars)	**Sept. 30, 2018**	**Sept. 30, 2017**
Major product lines		
Revenue from contracts with customers:		
Residential	$ 114,387	$ 113,380
Commercial and industrial (C&I)	229,457	241,295
Other	12,983	13,399
Total retail	356,827	368,074
Wholesale	117,949	116,635
Transmission	60,726	56,143
Other	1,792	3,862
Total revenue from contracts with customers	537,294	544,714
Alternative revenue and other	2,769	6,909
Total revenues	$ 540,063	$ 551,623

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(Thousands of Dollars)	Nine Months Ended Sept. 30, 2018	Sept. 30, 2017
Major product lines		
Revenue from contracts with customers:		
Residential	$ 279,543	$ 277,169
C&I	625,988	658,057
Other	34,010	35,253
Total retail	939,541	970,479
Wholesale	326,810	309,669
Transmission	175,342	166,715
Other	12,181	7,872
Total revenue from contracts with customers	1,453,874	1,454,735
Alternative revenue and other	14,759	36,756
Total revenues	$ 1,468,633	$ 1,491,491

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).

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on SPS' financial condition, results of operations, and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying unaudited financial statements and the related notes to the financial statements. Due to the seasonality of SPS' electric sales, such interim results are not necessarily an appropriate base from which to project annual results.

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 our 2018 earnings per share guidance, the TCJA's impact to SPS and its customers, long-term earnings per share and dividend growth rate, 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 securities filings (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2017, and subsequent securities filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: changes in environmental laws and regulations; unusual weather and climate change, including compliance with any accompanying legislative and regulatory changes; ability to recover costs from customers; actions of credit rating agencies; 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; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force factors.

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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. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from the most directly comparable measure calculated and presented in accordance with GAAP. SPS' management uses non-GAAP measures internally for financial planning and analysis, for reporting of results to the Board of Directors, and when communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our operating 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 Margins

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 recovery mechanisms, and as a result, changes in these expenses are offset in operating revenues. Management believes electric margin provides 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 operating and maintenance (O&M) expenses, demand side management (DSM) expenses, depreciation and amortization, and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $173 million for 2018 year-to-date, compared with approximately $128 million for the same period in 2017. The year-to-date increase was primarily due to higher AFUDC related to the Hale County wind project, timing of O&M expenses, the favorable impact of weather, sales growth, and lower interest expense, partially offset by higher depreciation expense.

Electric Revenues and Margin

Electric 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. The following tables detail the electric revenues and margin:

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2018**	**2017**
Electric revenues before impact of the TCJA	$ 1,513	$ 1,491
Electric fuel and purchased power	(802)	(816)
Electric margin before impact of the TCJA	$ 711	$ 675
Impact of the TCJA (offset as a reduction in income tax expense)	(38)	—
Electric margin	$ 673	$ 675

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The following tables summarize the components of the changes in electric revenues and electric margin for the nine months ended Sept. 30, 2018:

Electric Revenue

(Millions of Dollars)		2018 vs 2017
Fuel and purchased power cost recovery	$	(72)
Firm wholesale		(12)
Trading		42
Wholesale transmission revenue		25
Estimated impact of weather		18
Sales Growth		5
Demand revenue		5
Other, net		11
Total increase in electric revenues before impact of the TCJA	$	22
Impact of TCJA (offset as a reduction in income tax expense)		(44)
Total decrease in electric revenues	$	(22)

Electric Margin

(Millions of Dollars)		2018 vs 2017
Firm wholesale	$	(12)
Estimated impact of weather		18
Wholesale transmission revenue, net of costs		12
Sales growth		5
Demand revenue		5
Other, net		8
Total increase in electric margin before impact of the TCJA	$	36
Impact of TCJA (offset as a reduction in income tax expense)		(38)
Total decrease in electric margin	$	(2)

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses decreased $7 million, or 3.5 percent, for 2018 year-to-date. The decrease primarily relates to timing of O&M expenses.

Depreciation and Amortization — Depreciation and amortization increased $5 million, or 3.7 percent for 2018 year-to-date. The increase primarily relates to an increase in capital investments and planned system investments.

Income Taxes — Income tax expense decreased $36 million for the first nine months of 2018 compared with the same period in 2017. The decrease was primarily driven by a lower federal tax rate due to the TCJA and an increase in plant-related regulatory differences related to ARAM (net of deferrals). The ETR was 17.0 percent for the first nine months of 2018, compared with 35.9 percent for the same period in 2017. The lower ETR in 2018 is primarily due to the items referenced above. See Note 4 to the financial statements.

AFUDC, Equity and Debt — AFUDC increased $3 million for the third quarter of 2018 and increased $7 million year-to-date. The increase was primarily due to the Hale wind project and other capital investments.

Interest Charges — Interest charges decreased $4 million, or 6.6 percent, year-to-date. The decrease was related to refinancing at lower interest rates, partially offset by higher debt levels to fund capital investments.

Public Utility Regulation

Except to the extent noted below and in Note 5 in the notes to the financial statements, the circumstances set forth in Public Utility Regulation included in Item 1 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2017 and in Public Utility Regulation included in Item 2 of SPS' Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

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Texas State Right of First Refusal (ROFR) Request for Declaratory Order — In February 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility, operating in areas outside of Electric Reliability Council of Texas, the ROFR to construct new transmission facilities located in the utility's service area. SPP stated that Texas law does not provide a clear statement regarding the ROFR for incumbent utilities and therefore SPP was abiding by the portion of its OATT, which requires competitive solicitation to construct and operate new transmission facilities within areas of Texas' SPP footprint.

In October 2017, the PUCT issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities within its service area. In January 2018, SPS and two other parties filed appeals of the PUCT's order in the Texas State District Court. In September 2018, the District Court affirmed the PUCT's ROFR order. SPS plans to file an appeal in the fourth quarter of 2018.

Summary of Recent Federal Regulatory Developments

FERC

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, asset transactions and mergers, accounting practices and certain other activities of SPS, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2017 and Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018. In addition to the matters discussed below, see Note 5 to the financial statements for a discussion of other regulatory matters.

Xcel Energy, which includes SPS, attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and Commodity Futures Trading Commission jurisdictions. Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems. While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations.

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 chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Sept. 30, 2018, 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 the 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.

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Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

SPS is involved in various litigation matters that are being defended and handled 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 such losses that are 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.

Additional Information

See Note 6 to the financial statements for further discussion of legal claims and environmental proceedings. See Part I Item 2 and Note 5 to the financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

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, 2017, 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

3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997 (Exhibit 3.01 to Form 10-Q for the quarter ended Sept. 30, 2017 (file no. 001-03789)).
3.02*	By-Laws of SPS as Amended and Restated on Sept. 26, 2013 (Exhibit 3.02 to Form 10-Q/A for the quarter ended Sept. 30, 2013 (file no. 001-03789)).
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	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from SPS' Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Statements of Income, (ii) the Statements of Comprehensive Income (iii) the Statements of Cash Flows, (iv) the Balance Sheets, (v) Notes to Financial Statements, and (vi) document and entity information.

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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

Oct. 26, 2018

By: /s/ JEFFREY S. SAVAGE

Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Exhibit 31.01

CERTIFICATION

I, Ben Fowke, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Oct. 26, 2018

/s/ BEN FOWKE

Ben Fowke
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

Exhibit 31.02

CERTIFICATION

I, Robert C. Frenzel, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Public Service Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting

Date: Oct. 26, 2018

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Exhibit 32.01

OFFICER CERTIFICATION

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Southwestern Public Service Company (SPS) on Form 10-Q for the quarter ended Sept. 30, 2018, as filed with the SEC on the date hereof (Form 10-Q), each of the undersigned officers of SPS certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of SPS as of the dates and for the periods expressed in the Form 10-Q.

Date: Oct. 26, 2018

/s/ BEN FOWKE
Ben Fowke
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to SPS and will be retained by SPS and furnished to the SEC or its staff upon request.

Exhibit 99.01

SPS Cautionary Factors

The Private Securities Litigation Reform Act provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation, providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements are made in written documents and oral presentations of SPS, Xcel Energy Inc. or any of its other subsidiaries. These statements are based on management's beliefs as well as assumptions and information currently available to management. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause SPS' actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;
- The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;
- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where SPS has a financial interest;
- Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the FERC and similar entities with regulatory oversight;
- Availability of cost or capital such as changes in: interest rates; market perceptions of the utility industry, SPS, Xcel Energy Inc. or any of its other subsidiaries; or security ratings;
- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; cyber incidents; or electric transmission or natural gas pipeline constraints;
- Employee workforce factors, including loss or retirement of key executives, collective-bargaining agreements with union employees, or work stoppages;
- Increased competition in the utility industry or additional competition in the markets served by SPS, Xcel Energy Inc. and its other subsidiaries;
- State and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric market; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Environmental laws and regulations, including legislation and regulations relating to climate change, and the associated cost of compliance;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;
- Social attitudes regarding the utility and power industries;
- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;
- Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;
- Risks associated with implementation of new technologies; and
- Other business or investment considerations that may be disclosed from time to time in SEC filings, including "Risk Factors" in Item 1A of SPS' Form 10-K for the year ended Dec. 31, 2017, or in other publicly disseminated written documents.

SPS undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exhaustive.

2018 Form 10-K
For the Fiscal Year
Ended December 31, 2018

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, 2018

or

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

001-03789	75-0575400
(Commission File Number)	(I.R.S. Employer Identification No.)

(Registrant, State of incorporation or Organization, Address of Principal Executive Officers and Telephone Number)

SOUTHWESTERN PUBLIC SERVICE COMPANY

(a New Mexico company)
790 South Buchanan Street
Amarillo, Texas 79101
303-571-7511

Securities registered pursuant to Section 12(b) of the Act: None

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 and 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 if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 Act). ☐ Yes ☒ No

As of Feb. 22, 2019, 100 shares of common stock, par value $1 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 2019 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 1, 2019. 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 Instruction 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).

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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 on various filings with the SEC. This report should be read in its entirety.

PART I

Item I — Business

ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NCE	New Century Energies, Inc.
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
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NPRM	Notice of Proposed Rulemaking
PHMSA	Pipeline and Hazardous Materials Safety Administration
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric and Resource Adjustment Clauses	
DCRF	Distribution cost recovery factor
DSM	Demand side management
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
FPPCAC	Fuel and purchased power cost adjustment clause
PCRF	Power cost recovery factor
TCRF	Transmission cost recovery factor (recovers transmission infrastructure improvement costs and changes in wholesale transmission charges)

Other	
AFUDC	Allowance for funds used during construction
ARAM	Average rate assumption method
ARO	Asset retirement obligation
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
CAA	Clean Air Act
C&I	Commercial and Industrial
CO_2	Carbon dioxide
Corps	U.S. Army Corps of Engineers
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
EGU	Electric generating unit
ELG	Effluent limitations guidelines
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
IM	Integrated Marketplace
IPP	Independent power producing entity
ITC	Investment tax credit
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
NOx	Nitrogen oxide
NTC	Notifications to construct
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
Paris Agreement	Establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions")
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PTC	Production tax credit
QF	Qualifying facilities
REC	Renewable energy credit
ROE	Return on equity
ROFR	Right-of-first-refusal
RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
SERP	Supplemental executive retirement plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor's	Standard & Poor's Ratings Services
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
ppb	Parts per billion

Forward-Looking Statements

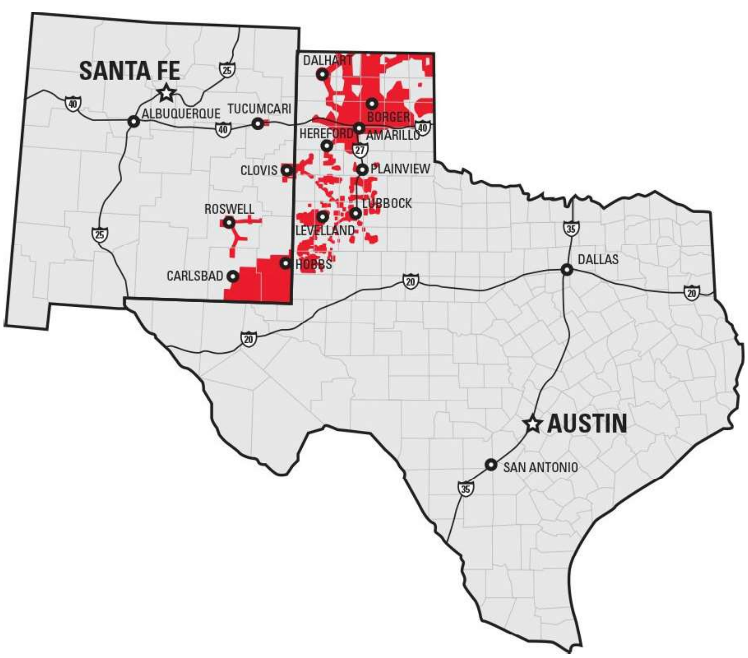
Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the TCJA's impact to SPS and its customers, as well as assumptions and other statements 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, 2018 (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: 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; ability to recover costs from customers; reductions in our credit ratings and the costs of maintaining certain contractual relationships; actions of credit rating agencies; 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; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

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.

COMPANY OVERVIEW

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.



SPS	
Electric customers	0.4 million
Earnings contribution	15% to 20%
Total assets	$6.7 billion
Electric generating capacity	4,406 MW

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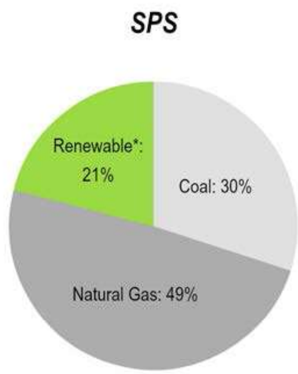
ELECTRIC UTILITY OPERATIONS

Electric Operating Statistics

	Year Ended Dec. 31		
	2018	2017	2016
Electric sales (Millions of KWh)			
Residential	3,645	3,356	3,478
Large C&I	11,214	10,721	10,518
Small C&I	5,041	4,701	4,708
Public authorities and other	550	527	555
Total retail	20,450	19,305	19,259
Sales for resale	10,060	7,759	8,689
Total energy sold	30,510	27,064	27,948
Number of customers at end of period			
Residential	308,884	306,248	305,076
Large C&I	232	221	219
Small C&I	77,269	77,351	77,319
Public authorities and other	6,322	6,316	6,377
Total retail	392,707	390,136	388,991
Wholesale	7	7	8
Total customers	392,714	390,143	388,999
Electric revenues (Millions of Dollars)			
Residential	$ 361.5	$ 367.2	$ 343.5
Large C&I	457.2	516.8	462.6
Small C&I	364.0	376.0	322.6
Public authorities and other	44.1	48.0	44.9
Total retail	1,226.8	1,308.0	1,173.6
Wholesale	427.9	388.7	414.8
Other electric revenues	278.5	221.3	262.6
Total electric revenues	$ 1,933.2	$ 1,918.0	$ 1,851.0
KWh sales per retail customer	52,074	49,483	49,510
Revenue per retail customer	$ 3,124	$ 3,353	$ 3,017
Residential revenue per KWh	9.92¢	10.94¢	9.88¢
Large C&I revenue per KWh	4.08	4.82	4.40
Small C&I revenue per KWh	7.22	8.00	6.85
Total retail revenue per KWh	6.00	6.78	6.09
Wholesale revenue per KWh	4.25	5.01	4.77

Energy Sources 2018



*Distributed generation from the Solar*Rewards® program is not included (approximately 13 million KWh for 2018).

Energy Source Statistics

In 2018, of SPS' total energy generation, 49% was owned and 51% was purchased. In 2017, 47% was owned and 53% was purchased.

Renewable Sources

SPS' renewable energy portfolio includes wind and solar power from PPAs. As of Dec. 31, 2018, SPS was in compliance with its applicable RPS. Renewable percentages will vary year over year based on local weather, system demand and transmission constraints.

SPS

Renewable energy as a percentage of SPS' total:

	2018	2017
Wind	19.1%	21.2%
Solar	2.0	2.8
Renewable	21.1%	24.0%

Wind — SPS has 18 PPAs with facilities ranging from under one MW to 250 MW.

- SPS had approximately 1,565 MW and 1,500 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under the IPP contracts and QF tariffs were approximately $26 and $27 for 2018 and 2017, respectively.
- In 2018, SPS began construction on the Sagamore and Hale County wind farms. Refer to the SPS Public Utility Regulation (Wind Development) section for further information.

Non-Renewable Sources

Delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation and the percentage of total fuel requirements represented by each category of fuel:

	Coal		Natural Gas	
	Cost	Percent	Cost	Percent
2018	$ 2.04	56%	$ 2.24	44%
2017	2.18	74	3.39	26

Weighted average cost per MMBtu of all fuels for owned electric generation were $2.13 in 2018 and $2.50 in 2017.

See Items 1A and 7 for further information.

Coal — Inventory maintained (in days):

Normal	Dec. 31, 2018 Actual	Dec. 31, 2017 Actual [(a)]
35 - 50	44	52

(a) Milder weather, purchase commitments and low power and natural gas prices impacted coal inventory levels.

Coal requirements were 5.1 million tons in 2018 and 5.5 million tons in 2017. Coal supply as a percentage of requirements for 2019 is 4.1 million tons or 64% of contracted coal supply. The general coal purchasing objective is to contract for approximately 75% of year one requirements, 40% of year two requirements and 20% of year three requirements.

Contracted coal transportation as a percentage of requirements in 2019 and 2020 is 100%.

Natural Gas — 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.

Contracts and commitments at Dec. 31:

(Millions of Dollars)	Gas Supply	Gas Transportation and Storage [(a)]
2018	$ 20	$ 152
2017	11	191
Year of Expiration	One year or less	2019 - 2033

(a) For incremental supplies, there are limited on-site fuel storage facilities, with a primary reliance on the spot market.

Capacity and Demand

Uninterrupted system peak demand for SPS for the last two years, is as follows:

System Peak Demand (in MW)			
2018		2017	
4,648	July 19	4,374	July 26

The peak demand typically occurs in the summer. The increase in peak load from 2017 to 2018 is partly due to warmer weather in 2018.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. The municipalities' rate setting decisions are subject to PUCT review, which has ultimate authority to set the rates SPS charges in the municipalities.

SPS is regulated by the FERC for its 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. SPS is a transmission-owning member of the SPP RTO and operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms —

- *DCRF* — Recovers distribution costs not included in rates in Texas.
- *EECRF* — Recovers costs for energy efficiency programs in Texas.
- *EE rider* — Recovers costs for energy efficiency programs in New Mexico.
- *FPPCAC* — Adjusts monthly to recover the actual fuel and purchased power costs in New Mexico.
- *PCRF* — Recovers purchased power costs not included in rates in Texas.
- *RPS* — Recovers deferred costs for renewable energy programs in New Mexico.
- *TCRF* — Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in base rates in Texas.

The fixed fuel and purchased energy recovery factor provides for the over- or under-recovery of energy expenses. 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.

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.

Energy Sources and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements. In addition, it has evaluated water supply issues at the Tolk facility, concluding additional resource investment will be required to operate the plant through its existing life. The Ogallala aquifer has depleted more rapidly than expected. SPS installed a horizontal water well that may help delay the need for a more substantial investment solution. As a result of this issue and future environmental rules facing the plant, it sought a decrease to the remaining life of the facility in the 2017 Texas and New Mexico rate case proceedings.

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.

Wind Development — In 2018, the NMPRC and PUCT approved SPS' proposal to add 1,230 MW of new wind generation, including ownership of 1,000 MW.

In March 2018, the NMPRC approved SPS' petition to build and own Sagamore, a 522 MW wind project in New Mexico which is expected to be placed into service in 2020. In May 2018, the PUCT approved SPS' petition to build and own Hale County, a 478 MW wind project in Texas which is expected to be placed into service in 2019. Both projects qualify for 100% of PTCs. SPS' capital investment for these wind projects is expected to be approximately $1.6 billion.

Texas State ROFR Request for Declaratory Order — In 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility the ROFR to construct new transmission facilities located in the utility's service area. The PUCT subsequently issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities. In January 2018, SPS and two other parties filed appeals in the Texas State District Court. In September 2018, the District Court affirmed the PUCT's ROFR order. SPS has filed an additional appeal.

Natural Gas Facilities Used for Electric Generation

SPS does not provide retail natural gas service, but purchases and transports natural gas for certain of its generation facilities and operates 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 to the jurisdiction of the PHMSA and the 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 hedge sales and purchases. See Item 7 for further information.

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.

See Item 7 for further information.

Competition

SPS is a vertically integrated utility subject to traditional cost-of-service regulation by state public utilities commissions. 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, but not limited to, 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, including Texas and New Mexico, have policies designed to promote the development of solar and other distributed energy resources through incentive policies. With these incentives and federal tax subsidies, distributed generating resources are potential competitors to SPS' electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, SPS can purchase generation resources from competing wholesale suppliers and use the transmission systems of Xcel Energy Inc.'s utility subsidiaries on a comparable basis to serve their native load.

FERC Order No. 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. State utilities commissions have also created resource planning programs that promote competition for electricity generation resources used to provide service to retail customers.

SPS has 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 facing these challenges, SPS believes its rates and services are competitive with alternatives currently available.

ENVIRONMENTAL MATTERS

SPS' facilities are regulated by federal and state environmental agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. SPS has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. SPS' facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon SPS' operations. SPS may be required to incur capital expenditures in the future to comply with requirements for remediation of MGP and other legacy sites. The scope and timing of these expenditures cannot be determined until more information is obtained regarding the need for remediation at legacy sites.

SPS must comply with emissions budgets that require the purchase of emission allowances from other utilities.

There are significant present and future 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. If future environmental regulations do not provide credit for the investments SPS has already made or if they require additional initiatives or emission reductions, substantial costs may be incurred. The EPA, as an alternative to the CPP, has proposed a new regulation that, if adopted, would require implementation of heat rate improvement projects at our coal-fired power plants. It is not known what those costs might be until a final rule is adopted and state plans are developed to implement a final regulation.

SPS believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

SPS is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Starting in 2011, SPS began reporting GHG emissions under the EPA's mandatory GHG Reporting Program.

EMPLOYEES

As of Dec. 31, 2018, SPS had 1,151 full-time employees and no part-time employees, of which 775 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. These risks should be carefully considered together with the other information set forth in this report and future reports that Xcel Energy files with the SEC.

Oversight of Risk and Related Processes

A key accountability of the Board of Directors is the oversight of material risk, and our Board of Directors employs an effective process for doing so. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of key risks.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and analysis occurs formally through a key risk assessment process by senior management, the financial disclosure process, hazard risk management procedures and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing SPS' strategy. The business planning process also identifies areas in which there is a potential for a business area to assume inappropriate risk to meet goals, and determines how to prevent inappropriate risk-taking.

At a threshold level, SPS has a robust compliance program and promotes a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. Building on this culture of compliance, management further mitigates risks through formal risk management structures, including management councils, risk committees and services of corporate areas such as internal audit, corporate controller and legal.

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. The presentation and the discussion of the key risks provides information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Oversight of cybersecurity risks by the Operations, Nuclear, Environmental and Safety Committee includes receiving independent outside assessments of cybersecurity maturity and assessment of plans.

Overall, the Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of SPS. Processes are in place to ensure appropriate risk oversight, as well as identification and consideration of new risks. The Board of Directors regularly reviews management's key risk assessment informed by these processes, and analyzes areas of existing and future risks and opportunities.

Risks Associated with Our Business

Operational Risks

Our electric transmission and distribution and gas 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 transmission and distribution activities also include inherent hazards and operating risks such as contact, fire and outages which could cause substantial financial losses. These natural gas and electric risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial losses. We maintain insurance against some, 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.

Additionally, for natural gas costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant. The Pipeline Safety Act requires verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

Our utility operations are subject to long-term planning 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 when they are brought in-service 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.

The electric utility sector is undergoing a period of significant change. For example, increases in appliance, lighting and energy efficiency, wider adoption and lower cost of renewable generation and distributed generation, shifts away from coal generation to decrease CO_2 emissions and increasing use of natural gas in electric generation driven by lower natural gas prices.

Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources as well as stranded costs if SPS is not able to fully recover the costs and investments. These changes also introduce additional uncertainty into long-term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide, and that the preference for the types of additions may change from planning to execution. In addition, we are subject to longer-term availability of the natural resource 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.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure. This increases the exposure to potential outdating of technologies and resultant risks. The inability of coal mining companies to attract capital could disrupt longer-term supplies. Decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation places downward pressure on sales growth. This may lead to under recovery of costs, excess resources to meet customer demand and increases in electric rates.

Finally, multiple states may not agree as to the appropriate resource mix and the differing views may lead to costs incurred to comply with one jurisdiction that are not recoverable across all of the jurisdictions served by the same assets.

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

If fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause 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. Low fuel costs have a positive impact on sales, however low oil and natural gas prices could negatively impact oil and gas production activities and subsequently our sales volumes and revenue.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Significantly higher energy or fuel costs relative to sales commitments have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and could cause disruptions in our ability to provide electric services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process.

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. Actual settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

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 Xcel Energy Inc. were to become obligated to make payments under various guarantees and bond indemnities or to fund its other contingent liabilities, or if either Standard & Poor’s or Moody’s were to downgrade Xcel Energy Inc.’s credit rating below investment grade, Xcel Energy Inc. may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures.

If either Standard & Poor’s 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, 2018, Xcel Energy Inc. and its utility subsidiaries had approximately \$15.8 billion of long-term debt and \$1.4 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, 2018, Xcel Energy had guarantees outstanding with a maximum stated amount of approximately $17.8 million and immaterial exposure. Xcel Energy also had additional guarantees of $51 million at Dec. 31, 2018 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.

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 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 2018, 2017 and 2016 we paid $131.0 million, $108.8 million and $85.1 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. In a continued low interest rate environment there has been pressure pushing down ROE. There can also be no assurance that our regulatory commissions will judge all of 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.

Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements of utility facilities and while regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs leaving all or a portion of these asset costs stranded. Higher than expected inflation or tariffs may increase costs of construction and operations. Rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers. Furthermore, there could be changes in the regulatory environment that would impair our ability to recover costs historically collected from our customers, or these factors could cause us to exceed commitments made regarding cost caps and result in less than full recovery. Overall, management currently believes prudently incurred costs are recoverable given the existing regulatory mechanisms in place.

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 ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including a disallowance of costs, significantly lower returns on equity or equity ratios or impacts of tax policy changes 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 downgrade could lead to higher borrowing costs and could impact our ability to access capital markets. Also, we may enter into contracts that require the posting of collateral or settlement of applicable contracts 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 markets are global and impacted by issues and events throughout the world. Capital market disruption events, 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.

Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the pension funds, as well as our ability to earn a return on short-term investments of excess cash.

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 overall economy and local economies in the geographic areas we serve, including local unemployment rates.

Credit risk also includes the risk that various counterparties that owe us money or product will become insolvent and/or 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 at times 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, such as SPP, PJM Interconnection, LLC, Midcontinent Independent System Operator, Inc. and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants.

We have additional indirect credit exposures to financial institutions in the form of 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 related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving SPS could trigger settlement accounting and could require SPS to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid.

Increasing costs associated with health care plans may adversely affect our results of operations, financial conditions or cash flows.

Our self-insured costs of health care benefits for eligible employees have increased in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial condition and cash flows. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

Federal tax law may significantly impact our business.

SPS collects through regulated rates estimated federal, state and local tax payments. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Changes to tax depreciable lives and the value of various tax credits may change the economics of resources and our resource selections. There could be timing delays before regulated rates provide for realization of the tax changes in revenues. In addition, certain IRS tax policies such as the requirement to utilize 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. Growth in customers and sales are correlated with economic conditions.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies and may lead to additional bad debt expense.

Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may impact our ability to acquire sufficient supplies. We operate in a capital intensive industry and federal policy on trade could significantly impact the cost of materials we use. We could be at risk for higher costs for materials and our workforce. There may be delays before these additional costs can be recovered in rates.

Our operations could be impacted by war, acts of terrorism, and threats of terrorism or disruptions due to 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, our 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 or an event (e.g., severe storm, severe temperature extremes, wildfires, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

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 begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. 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 causing the release of customer information, all of which 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 may expose software or hardware to these risks and could result in a breach or significant costs of remediation. In addition, such an event would likely receive federal and state regulatory scrutiny. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential 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 the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems or those of our third-party service providers were to fail or be breached, we may be unable to fulfill critical business functions. We are unable to quantify the potential impact of cyber security incidents on our business, our brand and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network monitoring 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.

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

We rely on third party contractors to perform work both for operations, maintenance and construction. We have contractual arrangements with these contractors which typically include performance standards, progress payments, insurance requirements and security for performance.

Cyber security breaches have at times exploited third party equipment or software in order to gain access. Poor vendor performance could impact on going operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

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 and new interpretations of existing laws create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant.

Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

Although the United States has not adopted any international or federal GHG emission reduction targets, many states and localities may continue to pursue climate policies in the absence of federal mandates. All of the steps that 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. While those actions likely would have put Xcel Energy in a good position to meet federal or international standards being discussed, the lack of federal action does not adversely impact these state-endorsed actions and plans.

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. Additionally, the PHMSA, Occupational Safety and Health Administration and other federal agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

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, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities. 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 (i.e., clean-up) sites where our past activities, or the activities of other parties, caused environmental contamination.

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 the 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.

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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. Extreme weather conditions in general require system backup, costs 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.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. 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 and increase the price paid for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's 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.

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.

SPS

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	251
Harrington-Amarillo, TX, 3 Units	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	411
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1998	209
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
		Total	4,406

(a) Summer 2018 net dependable capacity.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2018:

Conductor Miles	
345 KV	9,028
230 KV	9,675
115 KV	14,493
Less than 115 KV	25,820

SPS had 459 electric utility transmission and distribution substations at Dec. 31, 2018.

Natural gas utility mains at Dec. 31, 2018:

Miles	
Transmission	20
Distribution	—

Item 3 — Legal Proceedings

SPS is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessment of whether a loss is probable or is a reasonable possibility, and whether a loss or a range of loss is estimable, often involves a series of complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) damages sought are indeterminate, (2) proceedings are in the early stages or (3) 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.

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 2018 and 2017 were as follows:

(Millions of Dollars)	2018	2017
First quarter	$ 33.4	$ 26.7
Second quarter	30.7	25.0
Third quarter	40.1	26.2
Fourth quarter	45.2	26.8

Item 6 — Selected Financial Data

This is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

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, 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 Margins

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, cost of sales - other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Management uses these non-GAAP financial measures to evaluate and provide details of SPS' core earnings and underlying performance.

Management believes these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of SPS.

Results of Operations

SPS' net income was approximately $213.3 million for 2018, compared with net income of approximately $159.2 million for 2017. The increase was primarily due to higher electric margins reflecting favorable weather and sales growth and a rate increase in New Mexico, AFUDC related to the Hale County wind project and lower interest charges. Increases were partially offset by higher depreciation expense.

Electric Margin

Electric 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 before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017
Electric revenues before TCJA impact	$ 1,988.1	$ 1,918.0
Electric fuel and purchased power before TCJA impact	(1,050.1)	(1,055.3)
Electric margin before TCJA impact	$ 938.0	$ 862.7
TCJA impact (offset as a reduction in income tax)	(48.3)	—
Electric margin	$ 889.7	$ 862.7

The following tables summarize the components of the changes in electric margin for the year ended Dec. 31, 2018:

Electric Margin

(Millions of Dollars)	2018 vs. 2017
Wholesale transmission revenue (net of costs)	$ 21.6
Estimated impact of weather	19.9
Non-fuel riders	12.7
Demand revenue	8.7
Sales growth	8.3
Retail rate increase (New Mexico)	3.1
Firm wholesale	(10.8)
Other (net)	11.8
Total increase in electric margin before TCJA impact	$ 75.3
TCJA impact (offset as a reduction in income tax)	(48.3)
Total increase in electric margin	$ 27.0

Non-Fuel Operating Expense and Other Items

Depreciation and Amortization — Depreciation and amortization expense increased $15.7 million, or 8.1%, for 2018. The increase was primarily due to increased capital investments.

AFUDC, Equity and Debt — AFUDC increased by $13.3 million for 2018. The increase was primarily due to the Hale County Wind Project.

Income Taxes — Income tax expense decreased $29.5 million for 2018 compared with the same period in 2017. The decrease in income tax expense was primarily due to a lower federal tax rate due to the TCJA, an increase in plant-related regulatory difference related to ARAM (net of deferrals), and 2018 non-plant excess accumulated deferred income tax amortization.

This was partially offset by higher pretax earnings, a net tax benefit related to the resolution of appeals/audits in 2017, and the estimated one-time, non-cash, income tax expense related to the impacts of tax reform in 2017. The ETR was 15.4% for 2018 compared with 30.1% for 2017. The lower ETR in 2018 was primarily due to the adjustments referenced above.

Regulation

FERC and State Regulation — The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, asset transactions and mergers, accounting practices and certain other activities of SPS, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters.

Xcel Energy, which includes SPS, attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and Commodity Futures Trading Commission jurisdictions. Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems.

While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations. Decisions by these regulators can significantly impact SPS' results of operations.

Tax Reform — Regulatory Proceedings

In December 2017, the TCJA was signed into law, enacting significant changes to the Internal Revenue Code, including a reduction of the corporate income tax rate from 35% to 21% and a resulting reduction in deferred tax assets and liabilities. As a result of IRS requirements and past regulatory treatment of income taxes in the determination of regulated rates, the impacts of TCJA are primarily recognized as a regulatory liability. Treatment of these tax benefits, (e.g., degree to which benefits will be used to refund currently effective rates and/or used to mitigate other costs and potential future rate increases) is subject to regulatory approval. Concluded and ongoing regulatory TCJA proceedings:

Utility Service	Approval Date	Additional Information
Electric	December 2018	*Texas* — In December 2018, the PUCT approved a rate settlement which fully reflects the TCJA cost impacts and results in no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be up to a 57% equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings.
Electric	TBD	*New Mexico* — In September 2018, the NMPRC issued its final order in SPS' 2017 electric rate case, which included a $10 million refund of the 2018 impact of the TCJA. SPS subsequently filed an appeal with the NMSC, including the order to refund retroactive TCJA savings. The NMSC granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs. On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 and eliminate the retroactive TCJA refund. The revised NMPRC order would be subject to further administrative or judicial review.

See Note 7 to the financial statements for further information.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					SPS (PUCT)
Rate Case	Electric	$54	August 2017	Received	In 2017, SPS filed a retail electric, non-fuel base rate increase case in Texas, which included an ROE of 9.5%. In December 2018, PUCT issued a final order approving a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt. In November 2018, SPS filed an application with PUCT requesting permission to recover $5.4 million in unbilled TCRF revenue from January 23, 2018 through June 9, 2018. Timing of a final order on this matter is uncertain.
					SPS (NMPRC)
Rate Case	Electric	$41	November 2016	Pending	In 2017, SPS filed a notice of appeal to the New Mexico Supreme Court. A decision is not expected until the second half of 2019.
Rate Case	Electric	$43	October 2017	Received/ Pending	In September 2018, the NMPRC approved a revenue increase of approximately $8 million, effective Sept. 27, 2018, based on a ROE of 9.1% and a 51% equity ratio. The NMPRC also ordered a refund of $10 million associated with the TCJA impacts (retroactive Jan. 1, 2018 - Sept. 27, 2018). SPS recorded a regulatory liability for this amount in the third quarter of 2018. SPS subsequently filed an appeal of the order. The NMSC subsequently granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs. On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 with the following: eliminating the retroactive refund associated with the TCJA, approving a ROE of 9.56% and approving an equity ratio of 53.97%. Annual revenue increase based on terms of the settlement agreement would be $12.5 million ($8 million from original order plus $4.5 million for changes in ROE and equity ratio). New rates would be effective as of the date provided by the revised NMPRC order (not retrospective to Sept. 26, 2018), which is expected in the second quarter of 2019. The revised NMPRC order would be subject to further administrative or judicial review.

See Rate Matters within Note 10 to the financial statements for further information.

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 some 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 impact annual pretax interest expense by approximately $0.4 million in 2018 and no impact in 2017.

See Note 8 to the financial statements for further information.

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 monitors these policies to reflect changes and scope of operations.

At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $1.5 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $1.5 million. At Dec. 31, 2017, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $1.3 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $1.3 million.

SPS conducts credit reviews for all counterparties and employ 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 continuously 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, 2018.

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, 2018.

Item 8 — Financial Statements and Supplementary Data

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

See Note 13 to the financial statements for further information.

Management Report on Internal Controls 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, 2018. 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, 2018, SPS' internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ BEN FOWKE	/s/ ROBERT C. FRENZEL
Ben Fowke	Robert C. Frenzel
Chairman and Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 22, 2019	Feb. 22, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder 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, 2018 and 2017, the related statements of income, comprehensive income, cash flows and, common stockholder's equity for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2019

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

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SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating revenues	$ 1,933.2	$ 1,918.0	$ 1,851.0
Operating expenses			
Electric fuel and purchased power	1,043.5	1,055.3	1,035.0
Operating and maintenance expenses	282.7	285.4	265.5
Demand side management program expenses	17.7	15.5	16.0
Depreciation and amortization	209.6	193.9	162.4
Taxes (other than income taxes)	68.0	67.0	60.8
Total operating expenses	1,621.5	1,617.1	1,539.7
Operating income	311.7	300.9	311.3
Other expense, net	(3.0)	(1.8)	(3.9)
Allowance for funds used during construction — equity	19.1	9.3	10.0
Interest charges and financing costs			
Interest charges — includes other financing costs of $2.9, $2.5 and $3.1, respectively	84.5	86.2	88.7
Allowance for funds used during construction — debt	(8.9)	(5.4)	(5.6)
Total interest charges and financing costs	75.6	80.8	83.1
Income before income taxes	252.2	227.6	234.3
Income taxes	38.9	68.4	82.1
Net income	$ 213.3	$ 159.2	$ 152.2

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Net income	$ 213.3	$ 159.2	$ 152.2
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Amortization of losses (gains) included in net periodic benefit cost (net of tax of $0, $0, and $(0.1), respectively)	—	0.1	(0.1)
Derivative instruments:			
Reclassification of losses to net income (net of tax of $0, $0.1, and $0.1, respectively)	0.1	—	0.1
Other comprehensive income	0.1	0.1	—
Comprehensive income	$ 213.4	$ 159.3	$ 152.2

See Notes to Financial Statements

SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net income	$ 213.3	$ 159.2	$ 152.2
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	210.0	193.9	163.0
Demand side management program amortization	1.7	1.7	—
Deferred income taxes	22.1	126.5	123.0
Allowance for equity funds used during construction	(19.1)	(9.3)	(10.0)
Provision for bad debts	4.9	5.1	6.1
Net derivative losses	0.1	0.1	0.2
Changes in operating assets and liabilities:			
Accounts receivable	(19.5)	(10.4)	(8.9)
Accrued unbilled revenues	15.3	(10.4)	(15.6)
Inventories	(16.0)	(1.9)	(1.0)
Prepayments and other	0.5	4.3	22.7
Accounts payable	(6.6)	11.8	13.8
Net regulatory assets and liabilities	38.2	38.1	(55.7)
Other current liabilities	11.6	3.4	5.2
Pension and other employee benefit obligations	(16.0)	(21.7)	(15.3)
Other, net	5.8	(19.9)	8.1
Net cash provided by operating activities	446.3	470.5	387.8
Investing activities			
Utility capital/construction expenditures	(1,020.9)	(550.6)	(502.5)
Proceeds from insurance recoveries	—	—	3.9
Investments in utility money pool arrangement	(285.0)	(142.0)	(75.0)
Receipts from utility money pool arrangement	350.0	77.0	75.0
Other	—	(0.5)	(1.3)
Net cash used in investing activities	(955.9)	(616.1)	(499.9)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	42.0	(50.0)	35.0
Proceeds from issuance of long-term debt	295.0	442.3	296.0
Repayment of long-term debt, including reacquisition premiums	—	(271.6)	(200.0)
Borrowings under utility money pool arrangement	595.0	335.0	636.5
Repayments under utility money pool arrangement	(595.0)	(335.0)	(636.5)
Capital contributions from parent	336.8	143.7	66.2
Dividends paid to parent	(131.0)	(108.8)	(85.1)
Net cash provided by financing activities	542.8	155.6	112.1
Net change in cash and cash equivalents	33.2	10.0	—
Cash and cash equivalents at beginning of year	10.8	0.8	0.8
Cash and cash equivalents at end of year	$ 44.0	$ 10.8	$ 0.8
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (71.2)	$ (76.0)	$ (78.2)
Cash (paid) received for income taxes, net	(10.6)	41.5	61.8
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 71.5	$ 85.1	$ 49.5
Inventory transfer additions in PPE	22.5	13.7	22.6
Allowance for equity funds used during construction	19.1	9.3	10.0

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE CO.
BALANCE SHEETS
(amounts in millions, except share and per share data)

	Dec. 31 2018	Dec. 31 2017
Assets		
Current assets		
Cash and cash equivalents	$ 44.0	$ 10.8
Accounts receivable, net	90.7	79.6
Accounts receivable from affiliates	10.5	1.3
Investments in money pool arrangements	—	65.0
Accrued unbilled revenues	114.5	129.8
Inventories	33.9	40.4
Regulatory assets	26.0	31.5
Derivative instruments	17.8	15.9
Prepaid taxes	14.2	15.0
Prepayments and other	10.7	10.4
Total current assets	362.3	399.7
Property, plant and equipment, net	5,946.4	5,095.6
Other assets		
Regulatory assets	366.2	362.9
Derivative instruments	15.8	19.0
Other	5.1	11.3
Total other assets	387.1	393.2
Total assets	$ 6,695.8	$ 5,888.5
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 42.0	$ —
Accounts payable	191.8	211.8
Accounts payable to affiliates	19.9	22.6
Regulatory liabilities	85.8	68.8
Taxes accrued	41.6	35.2
Accrued interest	25.8	23.3
Dividends payable	45.2	26.8
Derivative instruments	3.6	3.6
Other	28.3	29.6
Total current liabilities	484.0	421.7
Deferred credits and other liabilities		
Deferred income taxes	619.1	574.9
Regulatory liabilities	780.9	784.6
Asset retirement obligations	32.4	28.5
Derivative instruments	16.4	20.0
Pension and employee benefit obligations	92.4	90.3
Other	7.9	8.3
Total deferred credits and other liabilities	1,549.1	1,506.6
Commitments and contingencies		
Capitalization		
Long-term debt	2,126.1	1,829.9
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at Dec. 31, 2018 and 2017, respectively	—	—
Additional paid in capital	1,932.3	1,590.2
Retained earnings	605.7	541.6
Accumulated other comprehensive loss	(1.4)	(1.5)
Total common stockholder's equity	2,536.6	2,130.3
Total liabilities and equity	$ 6,695.8	$ 5,888.5

See Notes to Financial Statements

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, 2015	100	$ —	$ 1,371.2	$ 438.0	$ (1.3)	$ 1,807.9
Net income				152.2		152.2
Common dividends declared to parent				(103.5)		(103.5)
Contribution of capital by parent			75.0			75.0
Balance at Dec. 31, 2016	100	$ —	$ 1,446.2	$ 486.7	$ (1.3)	$ 1,931.6
Net income				159.2		159.2
Other comprehensive loss					0.1	0.1
Common dividends declared to parent				(104.6)		(104.6)
Contribution of capital by parent			144.0			144.0
Adoption of ASU No. 2018-02				0.3	(0.3)	—
Balance at Dec. 31, 2017	100	$ —	$ 1,590.2	$ 541.6	$ (1.5)	$ 2,130.3
Net income				213.3		213.3
Other comprehensive income					0.1	0.1
Common dividends declared to parent				(149.2)		(149.2)
Contribution of capital by parent			342.1			342.1
Balance at Dec. 31, 2018	100	$ —	$ 1,932.3	$ 605.7	$ (1.4)	$ 2,536.6

See Notes to Financial Statements

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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 and disclosures 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.

SPS has evaluated the impact of events occurring after Dec. 31, 2018 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 on 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 when actual amounts can be determined. Those 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; and
- 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 or cash flows.

See Note 4 for further information.

Income Taxes — SPS accounts for income taxes using the asset and liability method, which requires 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 the tax 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 its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

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.

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.

SPS reports interest and penalties related to income taxes within the other income and interest charges in the statements of income.

Xcel Energy Inc. and its subsidiaries, including SPS, files 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 Notes 4 and 7 for further information.

Property, Plant and Equipment and Depreciation — 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.

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SPS records depreciation expense using the straight-line method over the plant's 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. Depreciation expense, expressed as a percentage of average depreciable property, was 2.9% in 2018, 2.8% in 2017, and 2.7% in 2016.

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. SPS also recovers through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

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. If an environmental expense is related to facilities currently in use, such as 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 PRPs 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 on a systematic basis 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 sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs 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, 2018 and 2017, the allowance for bad debts was $5.6 million and $6.3 million, respectively.

Inventory — Inventory is recorded at average cost. As of Dec. 31, 2018, materials and supplies and fuel inventory were $25.7 million and $8.2 million, respectively. As of Dec. 31, 2017, materials and supplies and fuel inventory were $26.2 million and $14.2 million, respectively.

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 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 under GAAP. 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. When certain criteria are met, such as 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 the total amount collected and the 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 in the period earned.

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 plus 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 purposes is recorded as electric fuel and purchased power expense. SPS reduces recoverable fuel costs for the cost of RECs and records that cost as a regulatory asset when the amount is 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.

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. Operating results from the regulated electric utility segment serve as the primary basis for the chief operating decision maker to evaluate the performance of SPS.

2. Accounting Pronouncements

Recently Issued

Leases — In 2016, the FASB issued *Leases, Topic 842 (ASU No. 2016-02)*, which requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. Adoption will occur on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions of whether agreements existing before the adoption date contain leases, and whether existing leases are operating or capital/finance leases. SPS expects to utilize other expedients offered by the new standard and *Leases, Topic 842 (ASU No. 2018-11)*, including elections to not recognize short term leases on the balance sheet for certain classes of assets and to implement the standard on a prospective basis. SPS' implementation of the new guidance is substantially complete, and is expected to result in the recognition of right-of-use assets and lease liabilities in the first quarter of 2019 for operating leases for the use of real estate, equipment and certain natural gas generating facilities operated under PPAs. The implementation is not expected to have a significant impact on SPS' financial statements, other than first-time recognition of these operating leases on the balance sheet.

Recently Adopted

Revenue Recognition — In 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 *(ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. SPS implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The implementation did not have a material impact on SPS' financial statements, other than increased disclosures regarding revenues related to contracts with customers.

Classification and Measurement of Financial Instruments — In 2016, the FASB issued Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 *(ASU No. 2016-01)*, which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. SPS implemented the guidance on Jan. 1, 2018 and the adoption impacts were not material.

Presentation of Net Periodic Benefit Cost — In 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost portion of pension cost may be presented as a component of operating income. In addition, only the service cost portion of pension cost is eligible for capitalization. As a result of regulatory accounting treatment, a similar amount of pension cost, including non-service components, will be recognized consistent with historical ratemaking and the impacts of adoption are limited to changes in classification of non-service costs in the statement of income.

SPS implemented the new guidance on Jan. 1, 2018. As a result, $4.1 million and $4.0 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other expense, net on the income statement for 2017 and 2016, respectively. SPS used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Property, Plant and Equipment

Major classes of property, plant and equipment:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Property, plant and equipment		
Electric plant	$ 7,227.7	$ 6,765.3
CWIP	847.3	351.9
Total property, plant and equipment	8,075.0	7,117.2
Less accumulated depreciation	(2,128.6)	(2,021.6)
	$ 5,946.4	$ 5,095.6

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, 2018		Dec. 31, 2017	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	9	Various	$ 12.6	$ 222.1	$ 12.7	$ 223.0
Excess deferred taxes - TCJA	7	Various	—	55.9	—	44.7
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	27.9	—	23.9
Net AROs [(a)]	1, 10	Plant lives	—	25.7	—	24.2
Losses on reacquired debt		Term of related debt	0.8	21.9	0.8	22.7
Conservation programs [(b)]	1	One to two years	0.7	0.6	2.7	0.7
Other		Various	11.9	12.1	15.3	23.7
Total regulatory assets			$ 26.0	$ 366.2	$ 31.5	$ 362.9

(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, 2018		Dec. 31, 2017	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 2.2	$ 569.8	$ —	$ 568.6
Plant removal costs	1, 10	Plant lives	—	187.7	—	196.9
Revenue subject to refund		One to two years	11.3	8.1	6.8	6.5
Gain from asset sales		Various	—	2.4	—	2.5
Deferred electric energy costs		Less than one year	56.5	—	48.5	—
Contract valuation adjustments [(b)]	1, 8	Less than one year	14.7	—	12.7	—
Other		Various	1.1	12.9	0.8	10.1
Total regulatory liabilities			$ 85.8	$ 780.9	$ 68.8	$ 784.6

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements.

At Dec. 31, 2018 and 2017, approximately $48 million and $64 million, respectively, of SPS' regulatory assets represented past expenditures not earning a return. Amounts primarily related to formula rates, losses on reacquired debt and certain rate case expenditures.

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5. Borrowings and Other Financing Instruments

Short-Term Borrowings

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 Dec. 31, 2018	Year Ended Dec. 31 2018	Year Ended Dec. 31 2017	Year Ended Dec. 31 2016
Borrowing limit	$ 100	$ 100	$ 100	$ 100
Amount outstanding at period end	—	—	—	—
Average amount outstanding	14	29	13	28
Maximum amount outstanding	74	100	100	100
Weighted average interest rate, computed on a daily basis	2.13%	1.96%	1.12%	0.67%
Weighted average interest rate at end of period	N/A	N/A	N/A	N/A

Commercial Paper — SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility.

Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018	Year Ended Dec. 31 2018	Year Ended Dec. 31 2017	Year Ended Dec. 31 2016
Borrowing limit	$ 400	$ 400	$ 400	$ 400
Amount outstanding at period end	42	42	—	50
Average amount outstanding	20	30	69	43
Maximum amount outstanding	100	144	176	140
Weighted average interest rate, computed on a daily basis	2.45%	2.27%	1.13%	0.67%
Weighted average interest rate at end of period	2.80	2.80	NA	0.95

Letters of Credit — SPS may use letters of credit, typically with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2018 and 2017, there were $2 million and $3 million of letters of credit outstanding, respectively, under the credit facility. Amounts approximate their fair value.

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)] 2018	Debt-to-Total Capitalization Ratio [(a)] 2017	Amount Facility May Be Increased (millions)	Additional Periods For Which a One-Year Extension May Be Requested [(b)]
46%	46%	$50	2

(a) The SPS 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 will 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, 2018, SPS was in compliance with all financial covenants.

SPS had the following committed credit facilities available as of Dec. 31, 2018.

Credit Facility [(a)]	Drawn [(b)]	Available
$400	$44	$356

(a) This credit facility matures in June 2021.

(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, 2018 and 2017.

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:

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Mortgage bonds	2024 - 2048	3.30% - 4.50%	3.30% - 4.50%	$ 1,800	$ 1,500
Unsecured senior notes	2033 - 2036	6.00%	6.00% - 8.75%	350	350
Unamortized discount				(4)	(2)
Unamortized debt issuance cost				(20)	(18)
Current maturities				—	—
Total long term debt				$ 2,126	$ 1,830

During the next five years, SPS has no long term debt maturities.

Deferred Financing Costs — Deferred financing costs of approximately $20 million and $18 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2018 and 2017, respectively. SPS is amortizing these financing costs over the remaining maturity periods of the related debt.

2018 financings:

Amount	Financing Instrument	Interest Rate	Maturity Date
$300 million	First mortgage bonds	4.40%	Nov 15, 2048

2017 financings:

Amount	Financing Instrument	Interest Rate	Maturity Date
$450 million	First mortgage bonds	3.70%	Aug 15, 2047

Capital Stock — SPS has the following preferred stock:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2018 and 2017
SPS	10,000,000	1.00	0

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 commission imposes the most restrictive dividend limitations.

Requirements and actuals as of Dec. 31, 2018:

Equity to Total Capitalization Ratio - Required Range		Equity to Total Capitalization Ratio - Actual [(a)]
Low	High	2018
45.0%	55.0%	54.4%

[(a)] SPS excludes short-term debt.

	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
	2018	2018	2018
SPS [(a)]	$ 605.7 million	$ 4.7 billion	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 (subsequent to adoption of the revised revenue guidance) consists of the following:

(Millions of Dollars)	Year Ended Dec. 31, 2018
Major product lines	
Revenue from contracts with customers:	
Residential	$ 363.7
C&I	828.3
Other	44.7
Total retail	1,236.7
Wholesale	426.0
Transmission	231.1
Other	12.8
Total revenue from contracts with customers	1,906.6
Alternative revenue and other	26.6
Total revenues	$ 1,933.2

7. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy (which includes SPS), generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for NOLs arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and,
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Xcel Energy estimated the effects of the TCJA, which have been reflected in the consolidated financial statements.

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Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of IRS requirements and past regulatory treatment.

Estimated impacts of the new tax law for SPS in December 2017 included:

- $426 million ($559 million grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over the average remaining life of the related property;
- $45 million and $28 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and,
- $8 million of total estimated income tax benefit related to the federal tax reform implementation, and a $2 million reduction to net income related to the allocation of Xcel Energy Services Inc.'s tax rate change on its deferred taxes.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Audit — 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 Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020
2017	September 2021

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. SPS did not accrue any income tax benefit related to this adjustment. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2018, the case has been forwarded to the Office of Appeals and 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.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016, however no adjustments have been proposed.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2018, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2010. There are currently no state income tax audits in progress.

Unrecognized Tax Benefits — 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 the 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)	Dec. 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 3.0	$ 2.3
Unrecognized tax benefit — Temporary tax positions	1.5	2.0
Total unrecognized tax benefit	$ 4.5	$ 4.3

Changes in unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 4.3	$ 28.7	$ 24.7
Additions based on tax positions related to the current year	0.6	0.9	1.4
Reductions based on tax positions related to the current year	(0.1)	(0.6)	—
Additions for tax positions of prior years	0.1	1.3	3.9
Reductions for tax positions of prior years	(0.3)	(19.9)	(1.3)
Settlements with taxing authorities	(0.1)	(6.1)	—
Balance at Dec. 31	$ 4.5	$ 4.3	$ 28.7

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (3.8)	$ (5.9)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $0.8 million and $2.7 million at Dec. 31, 2018 and Dec. 31, 2017, respectively.

As the IRS Appeals and federal audit progress and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3.6 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)	2018	2017	2016
Receivable (payable) for interest related to unrecognized tax benefits at Jan. 1	$ 0.5	$ (0.9)	$ —
Interest income (expense) related to unrecognized tax benefits	0.2	1.4	(0.9)
Receivable (payable) for interest related to unrecognized tax benefits at Dec. 31	$ 0.7	$ 0.5	$ (0.9)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2018, 2017, or 2016.

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)	2018	2017
Federal NOL carryforward	$ —	$ 115.0
Federal tax credit carryforwards	5.7	5.2
State NOL carryforwards	2.9	40.5

Federal carryforward periods expire between 2021 and 2038 and state carryforward periods expire between 2021 and 2036.

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:

	2018	2017 [(a)]	2016 [(a)]
Federal statutory rate	21.0%	35.0%	35.0%
State income tax on pretax income, net of federal tax effect	2.3%	2.0%	2.2%
Increases (decreases) in tax from:			
Regulatory differences - ARAM [(b)]	(4.2)	—	—
Tax Reform	—	(3.5)	—
Adjustments attributable to tax returns	(1.5)	(0.4)	(1.1)
Regulatory differences - other utility plant items	(1.3)	(0.8)	(1.0)
Amortization of excess nonplant deferred taxes	(1.2)	—	—
Tax credits recognized, net of federal income tax expense	(0.7)	(0.7)	(0.5)
Regulatory differences - Deferral of ARAM [(c)]	0.7	—	—
Change in unrecognized tax benefits	0.1	(1.0)	0.8
Other, net	0.2	(0.5)	(0.4)
Effective income tax rate	15.4%	30.1%	35.0%

(a) Prior periods have been reclassified to conform to current year presentation.

(b) ARAM is a method to flow back excess deferred taxes to customers.

(c) ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Current federal tax expense (benefit)	$ 12.3	$ (20.9)	$ (40.9)
Current state tax expense (benefit)	2.3	(12.8)	(2.9)
Current change in unrecognized tax expense (benefit)	2.3	(24.3)	3.1
Deferred federal tax expense	20.5	89.9	116.4
Deferred state tax expense	3.6	14.5	7.8
Deferred change in unrecognized tax (benefit) expense	(2.0)	22.1	(1.2)
Deferred ITCs	(0.1)	(0.1)	(0.2)
Total income tax expense	$ 38.9	$ 68.4	$ 82.1

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2018	2017	2016
Deferred tax expense (benefit) excluding items below	$ 44.2	$(414.2)	$128.4
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(22.0)	540.7	(5.4)
Tax (expense) benefit allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	(0.1)	—	—
Deferred tax expense	$ 22.1	$ 126.5	$123.0

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 680.6	$ 654.4
Regulatory assets	49.2	46.8
Pension expense	32.3	33.8
Other	2.9	4.6
Total deferred tax liabilities	$ 765.0	$ 739.6
Deferred tax assets:		
Regulatory liabilities	116.8	114.6
NOL carryforward	0.2	26.2
Deferred fuel costs	12.7	10.4
Other employee benefits	5.6	5.8
Tax credit carryforward	5.7	5.2
Other	4.9	2.5
Total deferred tax assets	$ 145.9	$ 164.7
Net deferred tax liability	$ 619.1	$ 574.9

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The 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 NAVs.

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 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, 2018, accumulated other comprehensive losses related to interest rate derivatives included $0.1 million 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.

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 commodity FTRs at Dec. 31, 2018 and 2017:

(Amounts in Millions) [(a)]	Dec. 31, 2018	Dec. 31, 2017
MWh of electricity	5.5	4.3

(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, 2018, two of the eight most significant counterparties for these activities, comprising $11.6 million or 28% of this credit exposure, had investment grade ratings from Standard & Poor's, Moody's or Fitch Ratings. Five of the eight most significant counterparties, comprising $8.7 million or 21% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising $0.6 million or less than 1% of this credit exposure, had credit quality less than investment grade, based on external analysis. Six of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate cash flow hedges on SPS' accumulated other comprehensive loss, included in the statements of common stockholder's equity and in the statements of comprehensive income:

(Millions of Dollars)	2018	2017	2016
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (0.8)	$ (0.7)	$ (0.8)
After-tax net realized losses on derivative transactions reclassified into earnings	0.1	—	0.1
Adoption of ASU. 2018-02 [(a)]	—	(0.1)	—
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (0.7)	$ (0.8)	$ (0.7)

(a) In 2017, SPS implemented ASU No. 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were $0.1 million, $0.1 million and $0.2 million for the years ended Dec. 31, 2018, 2017 and 2016, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains of $7.0 million, $0.5 million and $3.0 million recognized for the years ended Dec. 31, 2018, 2017 and 2016, respectively, 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 of $4.4 million, $0.8 million and $2.1 million were recognized for the years ended Dec. 31, 2018, 2017 and 2016, 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 years ended Dec. 31, 2018, 2017 and 2016.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2018 and 2017:

	Dec. 31, 2018						Dec. 31, 2017					
	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	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	$ 14.7	$ —	$ —	$ 14.7	$ 14.7	$ (2.0)	$ 12.7
Total current derivative assets	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	14.7	$ —	$ —	$ 14.7	$ 14.7	$ (2.0)	12.7
PPAs [(b)]						3.1						3.2
Current derivative instruments						$ 17.8						$ 15.9
Noncurrent derivative assets												
PPAs [(b)]						15.8						19.0
Noncurrent derivative instruments						$ 15.8						$ 19.0
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	$ —	$ —	$ —	$ 2.0	$ 2.0	$ (2.0)	$ —
Total current derivative liabilities	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	—	$ —	$ —	$ 2.0	$ 2.0	$ (2.0)	—
PPAs [(b)]						3.6						3.6
Current derivative instruments						$ 3.6						$ 3.6
Noncurrent derivative liabilities												
PPAs [(b)]						16.4						19.9
Noncurrent derivative instruments						$ 16.4						$ 19.9

(a) SPS nets derivative instruments and related collateral in its balance sheet 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, 2018 and 2017. At both Dec. 31, 2018 and 2017, 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, 2018, 2017 and 2016:

	Year Ended Dec. 31		
(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 12.7	$ 2.0	$ 5.1
Purchases	32.3	41.2	7.6
Settlements	(41.6)	(55.8)	(41.9)
Net transactions recorded during the period:			
Net gains recognized as regulatory assets	11.3	25.3	31.2
Balance at Dec. 31	$ 14.7	$ 12.7	$ 2.0

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2016 - 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2018		2017	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 2,126.1	$ 2,139.8	$ 1,829.9	$ 2,002.0

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, 2018 and 2017, 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

Xcel Energy, which includes SPS, has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. 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 that were participants 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, 2018 and 2017 were $33 million and $37 million, respectively, of which $2 million was attributable to SPS in 2018 and 2017. In 2018 and 2017, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million and $5 million, respectively, of which immaterial amounts were attributable to SPS.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan. Rabbi trust funding of deferred compensation plan distributions attributable to SPS will be supplemented by SPS's operating cash flows.

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- Xcel Energy discontinued health care benefits for SPS bargaining employees hired after Jan. 1, 2012.
- Xcel Energy discontinued subsidizing health care benefits for nonbargaining employees of the former NCE, which includes SPS employees, who retired after June 30, 2003.

Xcel Energy, which includes SPS, bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 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 2018 were below the assumed level of 6.78%;
- Investment returns in 2017 were above the assumed level of 6.78%;
- Investment returns in 2016 were below the assumed level of 6.78%; and,
- In 2019, Xcel Energy's expected investment-return assumption is 6.78%.

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 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.

Pension Plan Assets

The following presents, for each of the fair value hierarchy levels, SPS' pension plan assets measured at fair value:

	Dec. 31, 2018					Dec. 31, 2017				
(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	$ 21.6	$ —	$ —	$ —	$ 21.6	26.9	—	—	—	$ 26.9
Commingled funds:	128.6	—	—	132.5	261.1	145.7	—	—	142.7	288.4
Debt securities:	—	98.1	—	—	98.1	—	105.3	—	—	105.3
Equity securities:	14.4	—	—	—	14.4	15.2	—	—	—	15.2
Other	0.2	0.8	—	(4.0)	(3.0)	(3.3)	0.6	—	0.1	(2.6)
Total	$ 164.8	$ 98.9	$ —	$ 128.5	$ 392.2	$ 184.5	$ 105.9	$ —	$ 142.8	$ 433.2

The following presents, 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, 2018 [(a)]					Dec. 31, 2017 [(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	$ 1.8	$ —	$ —	$ —	$ 1.8	$ 2.8	$ —	$ —	$ —	$ 2.8
Insurance contracts	—	4.3	—	—	4.3	—	4.7	—	—	4.7
Commingled funds:	12.8	—	—	3.8	16.6	14.1	—	—	—	14.1
Debt securities:	—	17.2	—	—	17.2	—	19.0	—	—	19.0
Equity securities:	—	—	—	—	—	3.3	—	—	—	3.3
Other	—	0.1	—	—	0.1	—	0.2	—	—	0.2
Total	$ 14.6	$ 21.6	$ —	$ 3.8	$ 40.0	$ 20.2	$ 23.9	$ —	$ —	$ 44.1

(a) See Note 8 for further information on fair value measurement inputs and methods.

No assets transferred in or out of Level 3 for the years ended Dec. 31, 2018 or 2017.

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Funded Status — 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 presented in the following table:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2018	2017	2018	2017
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 515.9	$ 483.6	$ 47.0	$ 41.9
Service cost	9.7	9.8	1.1	0.9
Interest cost	18.4	19.7	1.6	1.7
Plan amendments	—	(1.0)	—	—
Actuarial (gain) loss	(34.8)	31.2	(5.1)	4.7
Plan participants' contributions	—	—	0.6	0.6
Benefit payments [(a)]	(31.4)	(27.4)	(3.4)	(2.8)
Obligation at Dec. 31	$ 477.8	$ 515.9	$ 41.8	$ 47.0
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 433.2	$ 380.4	$ 44.1	$ 42.3
Actual return on plan assets	(17.6)	56.7	(1.3)	3.8
Employer contributions	8.0	23.5	—	0.2
Plan participants' contributions	—	—	0.6	0.6
Benefit payments	(31.4)	(27.4)	(3.4)	(2.8)
Fair value of plan assets at Dec. 31	$ 392.2	$ 433.2	$ 40.0	$ 44.1
Funded status of plans at Dec. 31	$ (85.6)	$ (82.7)	$ (1.8)	$ (2.9)
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent liabilities	(85.6)	(82.7)	(1.8)	(2.9)
Net amounts recognized	$ (85.6)	$ (82.7)	$ (1.8)	$ (2.9)
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	4.31%	3.63%	4.32%	3.62%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	RP-2014	RP-2014	RP-2014	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50%	7.00%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.30%	5.50%
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

(a) Includes approximately $6.9 million in 2018 and $0 million in 2017, of lump-sum benefit payments used in the determination of a settlement charge.

Accumulated benefit obligation for the pension plan was $445.8 million and $478.8 million as of Dec. 31, 2018 and 2017, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit) other than service cost component is included in other income in the statement of income.

Components of net periodic benefit cost (credit) and the amounts recognized in other comprehensive income and regulatory assets and liabilities are as follows:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	2018	2017	2016	2018	2017	2016
Service cost	$ 9.7	$ 9.8	$ 9.8	$ 1.1	$ 0.9	$ 0.8
Interest cost	18.4	19.7	21.2	1.6	1.7	1.8
Expected return on plan assets	(28.3)	(27.9)	(27.6)	(2.5)	(2.4)	(2.4)
Amortization of prior service credit	(0.1)	—	—	(0.4)	(0.4)	(0.4)
Amortization of net loss	14.1	13.0	12.0	(0.4)	(0.6)	(0.6)
Settlement charge [(a)]	3.2	—	—	—	—	—
Net periodic pension cost (credit)	17.0	14.6	15.4	(0.6)	(0.8)	(0.8)
Costs not recognized due to effects of regulation	(2.2)	0.3	2.0	—	—	—
Net benefit cost (credit) recognized for financial reporting	$ 14.8	$ 14.9	$ 17.4	$ (0.6)	$ (0.8)	$ (0.8)
Significant Assumptions Used to Measure Costs:						
Discount rate	3.63%	4.13%	4.66%	3.62%	4.13%	4.65%
Expected average long-term increase in compensation level	3.75	3.75	4.00	—	—	—
Expected average long-term rate of return on assets	6.78	6.78	6.78	5.80	5.80	5.80

(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 2018, as a result of lump-sum distributions during the 2018 plan year, SPS recorded a total pension settlement charge of $3.3 million the majority of which $0 million was not recognized due to the effects of regulation.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2018	2017	2018	2017
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 230.9	$ 237.0	$ (9.6)	$ (8.6)
Prior service credit	(1.2)	(1.3)	(1.8)	(2.2)
Total	$ 229.7	$ 235.7	$ (11.4)	$ (10.8)
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	$ 12.9	$ 13.9	$ —	$ —
Noncurrent regulatory assets	216.8	221.8	—	—
Current regulatory liabilities	—	—	(0.9)	(0.8)
Noncurrent regulatory liabilities	—	—	(10.5)	(10.0)
Total	$ 229.7	$ 235.7	$ (11.4)	$ (10.8)
Measurement date	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2016 - 2019 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $150 million in January 2019, of which $17 million was attributable to SPS;
- $150 million in 2018, of which $8 million was attributable to SPS;
- $162 million in 2017, of which $24 million was attributable to SPS; and,
- $125 million in 2016, 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 under income tax and other retirement-related regulations 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:

- Expects to contribute approximately $11 million during 2019;
- $11 million during 2018;
- $20 million during 2017; and,
- $18 million during 2016.
- Amounts attributable to SPS were immaterial.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Domestic and international equity securities	35%	34%	18%	24%
Long-duration fixed income securities	32	31	—	—
Short-to-intermediate fixed income securities	16	19	70	60
Alternative investments	15	14	8	9
Cash	2	2	4	7
Total	100%	100%	100%	100%

Plan Amendments — Xcel Energy, which includes SPS, amended the Xcel Energy Inc. Nonbargaining Pension Plan (South) in 2017 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.

In 2018, there were no plan amendments made which affected the benefit obligation.

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
2019	29.7	3.2	—	3.2
2020	30.0	3.1	—	3.1
2021	29.3	3.2	—	3.2
2022	30.8	3.2	—	3.2
2023	30.8	3.2	—	3.2
2024-2028	156.2	14.4	0.2	14.2

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 2018, 2017 and 2016.

10. Commitments and Contingencies

Legal

SPS is involved in various litigation matters that are being defended and handled 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 complex judgments about future events. Management maintains accruals for losses that are 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 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, arising from such current proceedings would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

SPP OATT Upgrade Costs — Under the SPP OATT, costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately $13 million for these charges.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these charges was remanded to the FERC. SPS' recovery of these charges (from 2008 through 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC has granted a rehearing of further consideration in May 2018. The timing of the FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

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 could result in an increase in the ATRR of $9.5 million per year, with $6 million allocated to SPS' retail customers.

The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone. In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On October 31, 2018, the FERC issued an order accepting the proposed charges as of November 1, 2018. In December 2018, the FERC hosted a settlement hearing over the matter. A hearing will be ordered if a settlement is not reached.

SPS Filing to Modify Wholesale Transmission Rates - In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to the depreciation rates for transmission plant. The new formula rate would provide flow-back of "excess" ADIT resulting from the TCJA and recover certain wholesale regulatory commission expenses.

The proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total being recovered in SPP regional transmission rates. SPS proposed that the formula rate changes be effective February 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of February 1, 2019, subject to refund and settlement procedures. The first settlement conference is expected in the first quarter of 2019.

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 its 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.

MGP, Landfill or Disposal Sites — SPS is currently investigating or remediating one MGP, landfill or other disposal site across its service territories, and these activities will continue through at least 2019. SPS accrued $0.1 million as of Dec. 31, 2018 and 2017, respectively, for this site. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting some portion of costs incurred.

Environmental Requirements — Water and Waste

Federal CWA WOTUS Rule — In 2015, the EPA and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". The Rule has been subject to significant litigation and is currently stayed in a portion of the country. SPS cannot estimate potential impacts until the legal and administrative processes are finalized, but expects costs will be recoverable through regulatory mechanisms.

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 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, SPS estimates that ELG compliance will be immaterial.

The EPA, however, is conducting a rulemaking process to potentially revise the effluent limitations and pretreatment standards, which may impact compliance costs. SPS estimates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, NO_X and PM 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 as described below.

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 United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The 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. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. 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. It is not known when the EPA will make a final decision on this proposal.

Reasonable Progress Rule: In January 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, with compliance 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 are needed at Tolk under the "reasonable progress" requirements. The EPA has not announced a schedule for acting 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 an exception. The EPA issued final designations which found the area near the Harrington plant as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020.

If the area near the Harrington plant is designated nonattainment in 2020, the TCEQ will need to develop an implementation plan, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. SPS cannot evaluate the impacts until the final designation is made and any required state plans are developed. SPS believes that should SO_2 control systems be required for a plant, 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 position or cash flows.

AROs — AROs have been recorded for SPS' assets.

SPS' AROs were as follows:

(Millions of Dollars)	Dec. 31, 2018 Balance Jan. 1, 2018	Accretion	Cash Flow Revisions [(a)]	Balance Dec. 31, 2018 [(b)]
Electric				
Steam production	$ 20.3	$ 1.2	$ 0.5	$ 22.0
Distribution	7.0	0.3	1.8	9.1
Other	1.2	0.1	—	1.3
Total liability	$ 28.5	$ 1.6	$ 2.3	$ 32.4

(a) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in electric distribution AROs were primarily related to increased labor costs.

(b) There were no ARO amounts incurred or settled in 2018.

(Millions of Dollars)	Dec. 31, 2017 Balance Jan. 1, 2017	Accretion	Cash Flow Revisions [(a)]	Balance Dec. 31, 2017 [(b)]
Electric plant				
Steam production	$ 20.7	$ 1.3	$ (1.7)	$ 20.3
Distribution	6.8	0.2	—	7.0
Other	1.2	—	—	1.2
Total liability	$ 28.7	$ 1.5	$ (1.7)	$ 28.5

(a) In 2017, an asbestos ARO was revised for changes in timing of estimated cash flows.

(b) There were no ARO amounts incurred or settled in 2018.

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, 2018. Therefore, an ARO has not been recorded for these facilities.

Removal Costs — SPS records a regulatory liability for the plant removal costs that are recovered currently in rates. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates.

These removal costs have accumulated based on varying rates as authorized by the appropriate regulatory entities. SPS has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Removal costs as of Dec. 31, 2018 and 2017 were $188 million and $197 million respectively.

Leases — SPS leases a variety of equipment and facilities. These leases, primarily for office space, generating facilities, vehicles, aircraft and power-operated equipment, are accounted for as operating leases.

Total expenses (including capacity payments) under operating lease obligations for SPS and the corresponding capacity payments for PPAs accounted for as operating leases for the year ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Total expense	$ 59.0	$ 57.8	$ 56.6
Capacity payments	51.1	51.4	50.6

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases.

Future commitments under operating leases are:

(Millions of Dollars)	Operating Leases	PPA [(a) (b)] Operating Leases	Total Operating Leases
2019	$ 5.2	$ 46.7	$ 51.9
2020	5.2	46.2	51.4
2021	5.1	46.2	51.3
2022	5.1	46.2	51.3
2023	5.1	46.2	51.3
Thereafter	56.3	450.8	507.1

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2033.

Non-Lease PPAs — SPS has entered into PPAs with other utilities and energy suppliers with expiration dates through 2033 for purchased power to meet system load and energy requirements and meet operating reserve obligations.

In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Capacity payments are contingent on the IPP meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts, were payments for capacity of $57.6 million, $58.4 million and $56.8 million in 2018, 2017 and 2016, respectively.

At Dec. 31, 2018, 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
2019	$ 20.3
2020	12.0
2021	12.2
2022	12.4
2023	12.6
Thereafter	5.7
Total	$ 75.2

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 2019 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, 2018:

(Millions of Dollars)	Coal	Natural gas supply	Natural gas storage and transportation
2019	$ 127.3	$ 20.3	$ 30.3
2020	83.9	—	30.3
2021	41.0	—	25.2
2022	41.2	—	19.3
2023	—	—	14.1
Thereafter	—	—	33.6
Total	$ 293.4	$ 20.3	$ 152.8

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. 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 and 897 MW of capacity under long-term PPAs at Dec. 31, 2018 and 2017, respectively, 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 plant from TUCO 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. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the year ended Dec. 31:

	2018		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (0.8)	$ (0.7)	$ (1.5)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $0 and $0, respectively)	0.1 (a)	—	0.1
Amortization of net actuarial loss (net of taxes of $0 and $0, respectively)	—	— (b)	—
Net current period other comprehensive income	0.1	—	0.1
Accumulated other comprehensive loss at Dec. 31	$ (0.7)	$ (0.7)	$ (1.4)

	2017		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (0.7)	$ (0.6)	$ (1.3)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $0.1 and $0, respectively)	— (a)	—	—
Amortization of net actuarial loss (net of taxes of $0 and $0, respectively)	—	0.1 (b)	0.1
Net current period other comprehensive income (loss)	—	0.1	0.1
Adoption of ASU No. 2018-02 (c)	(0.1)	(0.2)	(0.3)
Accumulated other comprehensive loss at Dec. 31	$ (0.8)	$ (0.7)	$ (1.5)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for further information.

(c) In 2017, SPS implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within accumulated other comprehensive loss to retained earnings.

12. 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 the service 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, PSCo and SPS have established a utility money pool arrangement with the utility subsidiaries.

See Note 5 for further information.

Significant affiliate transactions among the companies and related parties for the years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Operating expenses:			
Purchased power	$ —	$ 1.4	$ 8.8
Other operating expenses — paid to Xcel Energy Services Inc.	195.1	196.6	188.2
Interest expense	0.6	—	0.2

Accounts receivable and payable with affiliates at Dec. 31 were:

	2018		2017	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 4.7	$ —	$ 1.0	$ —
PSCo	—	0.7	—	0.3
Other subsidiaries of Xcel Energy Inc.	5.8	19.2	0.3	22.3
	$ 10.5	$ 19.9	$ 1.3	$ 22.6

13. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Millions of Dollars)	March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$ 447.2	$ 481.3	$ 540.1	$ 464.6
Operating income	57.1	87.6	111.0	56.0
Net income	33.1	58.5	81.5	40.2

	Quarter Ended			
(Millions of Dollars)	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Operating revenues	$ 460.1	$ 479.8	$ 551.6	$ 426.5
Operating income (a)	59.2	75.2	123.1	43.4
Net income	25.1	35.3	67.8	31.0

(a) In 2018, SPS implemented ASU No. 2017-07 related to net periodic benefit cost, which resulted in retrospective reclassification of pension costs from O&M expense to other income.

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 chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure.

As of Dec. 31, 2018, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the chief executive officer and chief financial officer, of the effectiveness of its disclosure controls and the procedures, the chief executive officer and chief financial officer have concluded that SPS' disclosure controls and procedures were effective.

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Internal Control Over Financial Reporting

No change in SPS' internal control over financial reporting has occurred during SPS' most recent fiscal quarter that has materially affected, or is 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, 2018, 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 and as approved by the SEC and as indicated in Management Report on Internal Controls 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.

PART IV

Item 15 — Exhibits, Financial Statement Schedules

1	Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2018.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Statements of Income — For the three years ended Dec. 31, 2018, 2017 and 2016.
	Statements of Comprehensive Income — For the three years ended Dec. 31, 2018, 2017 and 2016.
	Statements of Cash Flows — For the three years ended Dec. 31, 2018, 2017 and 2016.
	Balance Sheets — As of Dec. 31, 2018 and 2017.
	Statements of Common Stockholder's Equity — For the three years ended Dec. 31, 2018, 2017 and 2016.
2	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2018, 2017 and 2016.
3	Exhibits

*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	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	001-03789	3.01
3.02	By-Laws of SPS as Amended and Restated on Jan. 25, 2019			
4.01*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	001-03789	99.2
4.02*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 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	001-03034	4.04
4.03*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee	SPS Form 8-K dated Oct. 3, 2006	001-03789	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	001-03789	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 No. 1 due 2041	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.02
4.06*	Sixth Supplemental Indenture dated as of June 1, 2014 between SPS and the Bank of New York Mellon Trust Company, N.A., as successor Trustee	SPS Form 8-K dated June 2, 2014	001-03789	4.03

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 Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

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 2019 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 1, 2019. Such information set forth under such heading is incorporated herein by this reference hereto.

4.07*	Supplemental Indenture No. 3 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 No. 3 due 2024	SPS Form 8-K dated June 9, 2014	001-03789	4.02
4.08*	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 No. 4 due 2046	SPS Form 8-K dated Aug. 12, 2016	001-03789	4.02
4.09*	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 No. 5 due 2047	SPS Form 8-K dated Aug. 9, 2017	001-03789	4.02
4.10*	Supplemental Indenture No. 6 dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating 4.40% First Mortgage Bonds, Series No. 6 due 2048	SPS Form 8-K dated Nov. 5, 2018	001-03789	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	001-03034	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	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	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	001-03034	10.17
10.06*+	Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06
10.07*+	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	001-03034	10.08
10.08*+	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	001-03034	Schedule 14A
10.09*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A
10.10*+	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	001-03034	Schedule 14A
10.11*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.12*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.13*+	First Amendment to Exhibit 10.11 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.14*+	First Amendment to Exhibit 10.08 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.15*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.16*+	First Amendment to Exhibit 10.09 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.21
10.17*+	Second Amendment to Exhibit 10.11 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.18*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.23
10.19*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2015	001-03034	Schedule 14A
10.20*+	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	001-03034	10.02
10.21*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.03
10.22*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.28
10.23*+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.29
10.24*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.25*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 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, and Wells Fargo Bank, National Association, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.04
10.26*+	Third Amendment to Exhibit 10.11 dated Sept. 30, 2016	Xcel Energy inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.27*+	Form of Xcel Energy, Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2016	001-03034	10.27
10.28*+	Fourth Amendment to Exhibit 10.11 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.29*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30

10.30*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.31*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.34
10.32*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.35
10.33*+	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	001-03034	10.36
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	The following materials from SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Statements of Income, (ii) the Statements of Comprehensive Income, (iii) the Statements of Cash Flows, (iv) the Balance Sheets, (v) the Statements of Stockholder's Equity, (vi) Notes to Financial Statements, (vii) document and entity information, and (viii) Schedule II.			

SCHEDULE II

SOUTHWESTERN PUBLIC SERVICE CO.
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2018, 2017 AND 2016

	Allowance for bad debts		
(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 6.4	$ 6.4	$ 5.9
Additions Charged to Costs and Expenses	4.9	5.1	6.1
Additions Charged to Other Accounts [(a)]	1.0	1.2	0.9
Deductions from Reserves [(b)]	(6.7)	(6.3)	(6.5)
Balance at Dec. 31	$ 5.6	$ 6.4	$ 6.4

(a) Recovery of amounts previously written off.

(b) Deductions relate primarily to bad debt write-offs.

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.

SOUTHWESTERN PUBLIC SERVICE COMPANY

Feb. 22, 2019	/s/ ROBERT C. FRENZEL
	Robert C. Frenzel Executive Vice President, Chief Financial Officer and Director (Principal 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/ BEN FOWKE	/s/ DAVID T. HUDSON
Ben Fowke Chairman, Chief Executive Officer and Director (Principal Executive Officer)	David T. Hudson President and Director
/s/ ROBERT C. FRENZEL	/s/ JEFFREY S. SAVAGE
Robert C. Frenzel Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	Jeffrey S. Savage Senior Vice President, Controller (Principal Accounting Officer)
/s/ DAVID L. EVES	
David L. Eves Executive Vice President and Director	

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.

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-224333-01 on Form S-3 of our report dated February 22, 2019, relating to the financial statements and financial statement schedule of Southwestern Public Service Company appearing in this Annual Report on Form 10-K of Southwestern Public Service Company for the year ended December 31, 2018.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2019

Exhibit 31.01

CERTIFICATION

I, Ben Fowke, certify that:

1. I have reviewed this report on Form 10-K of Southwestern Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 22, 2019

/s/ BEN FOWKE

Ben Fowke
Chairman, Chief Executive Officer and Director

Exhibit 31.02

CERTIFICATION

I, Robert C. Frenzel, certify that:

1. I have reviewed this report on Form 10-K of Southwestern Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 22, 2019

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director

Exhibit 32.01

OFFICER CERTIFICATION

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Southwestern Public Service Company (SPS) on Form 10-K for the year ended Dec. 31, 2018, as filed with the SEC on the date hereof (Form 10-K), each of the undersigned officers of SPS certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of SPS as of the dates and for the periods expressed in the Form 10-K.

Date: Feb. 22, 2019

/s/ BEN FOWKE

Ben Fowke
Chairman, Chief Executive Officer and Director

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to SPS and will be retained by SPS and furnished to the SEC or its staff upon request.

Exhibit 3.02

SOUTHWESTERN PUBLIC SERVICE COMPANY

AMENDED AND RESTATED BYLAWS

(as amended and restated January 25, 2019)

ARTICLE I

Shareholders

Section 1. Annual Meeting. The annual meeting of the shareholders of the Company for the election of directors and for the transaction of any other business that may be properly brought before the meeting shall be held at a place, date, and hour designated by either the Chairman of the Board or the President or by resolution of the Board of Directors.

Section 2. Special Meetings. Special meetings of the shareholders for any purpose or purposes shall be called by the Secretary upon receipt of a written request from the Chairman of the Board, the President, a majority of the directors, or any person or persons authorized by the New Mexico Business Corporation Act (the "Act") to request such a meeting. Special meetings of the shareholders shall be held at a place, date, and hour designated by the Chairman of the Board, the President, or by resolution of the Board of Directors.

Section 3. Notice. Written notice of all meetings of shareholders stating the place, date, and hour of the meeting and, in the case of special meetings, the purpose or purposes for which the meeting is called, shall be given to each shareholder entitled to vote at such meeting not less than ten or more than 50 days before the date of the meeting, either by mail, electronic mail, facsimile telephone, personal service or any other means as may be permitted by law. Attendance at a meeting constitutes a waiver of notice, except where the shareholder attends a meeting for the express purpose of objecting to the transaction of any business because the meeting is not lawfully called or convened.

Section 4. Procedure. At each meeting of the shareholders, the Chairman of the Board or, in his or her absence, the President shall act as chairman of the meeting. The chairman of the meeting shall determine the order of business and all other matters of procedure. The chairman of the meeting may establish rules to maintain order and to conduct the meeting. The chairman of the meeting shall act in his or her absolute discretion, and his or her rulings are not subject to appeal.

Section 4. Action Without a Meeting. An action required or permitted to be taken at a meeting of the shareholders may be taken without a meeting by written action signed, or consented to by authenticated electronic communication, by all of the shareholders entitled to a vote on such action. The written action is effective when it has been signed, or consented to, by all of those shareholders, unless a different time is provided in the written action.

ARTICLE II

Directors

Section 1. Board of Directors. The business of the Company shall be managed by a Board of Directors. The number of directors constituting the Board of Directors shall be established from time to time by resolution of the Board of Directors, subject to any limitations set forth in the Amended and Restated Articles of Incorporation. A Chairman of the Board may be chosen from among the directors.

Section 2. Regular Meetings. Regular meetings of the Board of Directors may be held without notice at times and places determined by the Board of Directors. Attendance of a director at a meeting constitutes a waiver of notice of the meeting, except where a director attends a meeting for the express purpose of objecting to the transaction of any business because the meeting is not lawfully called or convened.

Section 3. Special Meetings. Special meetings of the Board of Directors may be called by a director or by the chief executive officer of the Company on 24 hours' notice to all directors of the date, time and place of the meeting. The notice shall be given to each director by mail, electronic mail, facsimile telephone, personal service or any other means as may be permitted by law and need not state the purpose of the meeting.

Section 4. Adjournment of Meetings. The directors may adjourn from time to time any regular or special meeting at which a quorum is present, without notice other than announcement at the meeting. The adjourned meeting may be called to order at any time without further notice, and any business may be transacted which might have been transacted at the original meeting.

Section 5. Authority to Appoint Committees and Delegate Authority. The Board of Directors, by resolution adopted by a majority of the full Board of Directors, may designate from among its members one or more committees, each of which, except to the extent limited by law, the Amended and Restated Articles of Incorporation, these Bylaws, and the resolution establishing the committee, shall have and may exercise all of the authority of the Board of Directors, and may also prescribe rules of operation of the committee. Regular meetings of any committee may be held without notice at times and places determined by the Board of Directors or the committee. Special meetings of any committee shall be called by the Secretary upon the receipt of a request from the Chairman of the Board, the President, the chairman of the committee, or any member of the committee. Notice of special meetings shall be given in the same manner as provided in Section 3 of this Article II.

Section 6. Action Without a Meeting. An action required or permitted to be taken at a board meeting or by a lawfully appointed committee thereof may be taken by written action signed, or consented to by authenticated electronic communication, by all of the directors or by all of the members of such committee, unless the action need not be approved by the shareholders and the Amended and Restated Articles of Incorporation so provide, in which case, the action may be taken by written action signed, or consented to by authenticated electronic communication, by the number of directors that would be required to take the same action at a meeting of the Board of Directors or the committee at which all directors or committee members were present. The written action is effective when signed or consented to by the required number of directors or committee members unless a different effective time is provided in the written action. When written action is permitted to be taken by less than all directors or committee members, all directors and committee members shall be notified immediately of its text and effective date.

ARTICLE III

Officers

Section 1. Number. The officers of the Company shall be a President, a Secretary, and a Treasurer, and may include a Chairman of the Board, a chief executive officer, a chief financial officer, one or more Vice Presidents (one or more of whom may be designated Executive Vice President, Senior Vice President or as otherwise determined by the Board of Directors), a Controller, and/or a chief accounting officer.

Section 2. Election and Term of Office. Each officer shall be elected by the Board of Directors and shall hold office until his or her successor has been elected and qualified or until his or her earlier retirement, disability, death, resignation, or removal.

Section 3. Removal and Vacancies. Any officer may be removed at any time with or without cause by the Board of Directors. A vacancy in any office may be filled for the unexpired portion of the term in the same manner as provided for election to the office.

Section 4. Assistant Officers. The Company may have such assistant officers as the Board of Directors may elect. Each assistant officer shall hold office at the pleasure of, and may be removed at any time with or without cause by, the Board of Directors. Assistant officers may include one or more Assistant Vice Presidents, Assistant Secretaries, Assistant Treasurers, and Assistant Controllers.

Section 5. Duties. Each officer shall have the authority and shall perform the duties as may be assigned by the Board of Directors, the Chairman of the Board, or the President, or as shall be conferred or required by law or these Bylaws, or as shall be normally incidental to the office. The President, the chief executive officer, the chief financial officer, and any Vice President of the Company may execute and deliver instruments and contracts on behalf of the Company and otherwise may bind the Company. Unless prohibited by the Board of Directors, an officer may, without the approval of the Board of Directors, delegate in writing to any other person some or all of the duties and powers of his or her office to other persons. The President, the chief executive officer, the chief financial officer, any Vice President of the company, and any other person or persons pursuant to delegated authority or as may be designated or authorized from time to time by the Board of Directors of the chief executive officer may execute and deliver contracts, deeds, mortgages, notes checks, conveyances, releases of mortgages and other instruments on behalf of the Company and otherwise may bind the Company.

ARTICLE IV

Indemnification of Directors, Officers, Employees, and Agents

Section 1. Mandatory Indemnification. Each person who is a party or is threatened to be made a party, either as plaintiff, defendant, respondent, or otherwise, to any action, suit, or proceeding, whether civil, criminal, administrative, or investigative (a "Proceeding"), based upon, arising from, relating to, or by reason of the fact that such person, or a person of whom such person is the legal representative, is or was a director or officer of the Company, or is or was serving at the request of the Company as a director, officer, partner, trustee, employee, or agent of another foreign or domestic corporation or non-profit corporation, cooperative, partnership, joint venture, trust, or other incorporated or unincorporated enterprise, or any employee benefit plan or trust (each, a "Company Affiliate"), shall be indemnified and held harmless by the Company to the fullest extent authorized by the Act, as the same exists on the date of the adoption of these Bylaws or as may hereafter be amended (but, in the case of any such amendment, only to the extent that such amendment permits the Company to provide broader indemnification rights than permitted by the Act prior to such amendment), against any and all expenses, liability, and loss (including, without limitation, investigation expenses and expert witnesses' and attorneys' fees and expenses, judgments, penalties, fines, and amounts paid or to be paid in settlement) actually incurred by such person in connection therewith. The right to indemnification conferred in this Article IV shall be a contract right and shall include the right to be paid by the Company for expenses incurred in defending or prosecuting any Proceeding in advance of its final disposition.

Any person seeking indemnification pursuant to this Section 1 of Article IV shall submit a written claim and include the undertakings and/or affirmations required by Section 53-11-4.1 of the Act; provided that no person shall be indemnified unless the Company has determined that indemnification is proper under the Act.

For purposes of this Article IV, references to "fines" shall include any excise taxes assessed on a person with respect to any employee benefit plan or trust; and references to "serving at the request of the Company" shall include any service as a director, officer, employee, or agent of the Company which imposes duties on, or involves services by, such director, officer, employee, or agent with respect to an employee benefit plan or trust, its participants, or beneficiaries; and a person who acted in good faith and in a manner such person reasonably believed to be in the interest of the participants and beneficiaries of an employee benefit plan or trust shall be deemed to have acted in a manner "not opposed to the best interests of the Company."

The Company's indemnity of any person who was or is serving at its request as a director, officer, partner, trustee, employee, or agent of a Company Affiliate shall be reduced by any amounts such person may collect as indemnification from such Company Affiliate.

Section 2. Recovery Against the Company. If a claim under Section 1 of this Article IV is not paid in full by the Company within thirty days after a written claim has been received by the Company, except in the case of a claim for expenses to be incurred in defending a Proceeding in advance of its final disposition (in which case the applicable period shall be ten days), the claimant may at any time thereafter bring suit against the Company to recover the unpaid amount of the claim and, if wholly successful, on the merits or otherwise, the claimant shall be entitled to be paid also the expense of prosecuting such claim. The claimant shall be presumed to be entitled to indemnification under this Article IV upon submission of a written claim (and any required undertaking and/or affirmations required by the Act) and thereafter the Company shall have the burden of proof to overcome the presumption that the claimant is not so entitled. Neither the failure of the Company (including its Board of Directors, independent legal counsel, or its shareholders) to have made a determination prior to the commencement of such action that indemnification of the claimant is proper in the circumstances because such person has met the applicable standard of conduct set forth in the Act, nor an actual determination by the Company (including its Board of Directors, independent legal counsel, or its shareholders) that the claimant has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that the claimant has not met the applicable standard of conduct.

Section 3. Non-Exclusive Right. The right to indemnification and the payment of expenses incurred in defending a Proceeding in advance of its final disposition conferred in this Article IV shall not be exclusive of any other right to which any person may be entitled under any statute, provision of the Amended and Restated Articles of Incorporation, or Bylaw, any agreement, a resolution of shareholders or directors, or otherwise both as to action in such person's official capacity and as to action in another capacity while holding such office.

Section 4. Insurance. The Company may purchase and maintain insurance or furnish similar protection, including, but not limited to, providing a trust fund, letter of credit, or self-insurance, on behalf of any person who is a director, officer, employee, or agent of the Company or who, while a director, officer, employee, or agent of the Company, is serving at the request of the Company as a director, officer, partner, trustee, employee, or agent of a Company Affiliate, against any liability asserted against and incurred by such director, officer, employee, or agent in such capacity or arising out of such director's, officer's, employee's, or agent's status as such, whether or not the Company would have the power to indemnify such director, officer, employee, or agent against such liability under the Act.

Section 5. Delegation of Authority. The Company may, by action of its Board of Directors, authorize one or more officers to grant rights to indemnification and advancement of expenses to employees or agents of the Company on such terms and conditions as such officer or officers deem appropriate under the circumstances.

Section 6. Continuing Effect. The indemnification and advancement of expenses provided by, or granted pursuant to, this Article IV shall, unless otherwise provided when authorized, continue as to a person who has ceased to be a director, officer, employee, or agent and shall inure to the benefit of the heirs, executors, and administrators of such persons. Anything in this Article IV to the contrary notwithstanding, no elimination or amendment of this Bylaw adversely affecting the right of any person to indemnification or advancement of expenses hereunder shall be effective until the sixtieth day following notice to such indemnified person of such action, and no elimination or amendment of these Bylaws shall deprive any such person of such person's rights hereunder arising out of alleged or actual occurrences, acts, or failures to act which had their origin prior to such sixtieth day.

Section 7. Severability. In case any provision in this Article IV shall be determined at any time to be unenforceable in any respect, the other provisions shall not in any way be affected or impaired thereby, and the affected provision shall be given the fullest possible enforcement in the circumstances, it being the intention of the Company to afford indemnification and advancement of expenses to the persons indemnified hereby to the fullest extent permitted by law.

ARTICLE V

Share Certificates and Transfer of Shares

Section 1. Share Certificates. Shares of stock of the Company may, at the discretion of the Board of Directors, be represented by certificates or may be uncertificated. Any share certificates of the Company shall be in the form and contain the provisions determined by the Board of Directors and required by the Act.

Section 2. Transfer Rules. The Board of Directors, the Chairman of the Board, the President, or the Secretary may from time to time promulgate rules or regulations as it or such officer may deem advisable concerning the issue, transfer, registration, or replacement of share certificates of the Company.

Section 3. Registered Shareholders. The Company shall be entitled to treat the holder of record of any share or shares as the holder in fact of those shares. The Company shall not be bound to recognize any equitable or other claim to or interest in any shares on the part of any other person, regardless of whether the Company has actual or imputed knowledge of a claim of interest, except as otherwise required by the Act.

ARTICLE VI

General Provisions

Section 1. Fiscal Year. The fiscal year of the Company shall begin on the first day of January and end on the last day of December each year.

Section 2. Seal. The Company may, but need not, have a corporate seal. If the Company has a corporate seal, the use of the seal by the Company on a document is not required, and the use or nonuse of the seal does not affect the validity, recordability, or enforceability of a document or act. The seal of the Company need only include the name of the Company. If a corporate seal is used, it or a facsimile of it may be affixed, engraved, printed, placed, stamped with indelible ink, or in any other manner reproduced on any document.

Section 3. Voting of Shares of Other Corporations. The shares of any other corporation owned by the Company may be voted at any meeting of the shareholders of such other corporation by such proxy as the Board of Directors of the Company may appoint, or if no such appointment be made, by the chief executive officer.

Section 4. Dividends. Subject to any restrictions set forth in the Amended and Restated Articles of Incorporation, dividends on the shares of the Company may be declared by the Board of Directors at any regular or special meeting, pursuant to the Act.

ARTICLE VII

Amendments

These Bylaws may be altered, amended, or repealed by the affirmative vote of a majority of the Board of Directors then in office. These Bylaws may also be altered, amended, or repealed by the shareholders by the affirmative vote of the holders of a majority in interest of the shares issued and outstanding and entitled to vote.

* * * * *

2019 Form 10-Q
For the Quarterly Period
Ended March 31, 2019

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, 2019 or

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

001-3034	75-0575400
(Commission File Number)	(I.R.S. Employer Identification No.)

(Registrant, State of Incorporation or Organization, Address of Principal Executive Officers and Telephone Number)

SOUTHWESTERN PUBLIC SERVICE COMPANY

(a New Mexico corporation)
790 South Buchanan Street
Amarillo, Texas 79101
303-571-7511

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 and 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 26, 2019
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.

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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 SEC. This report should be read in its entirety.

ABBREVIATIONS AND INDUSTRY TERMS

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
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NMSC	New Mexico Supreme Court
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Electric and Resource Adjustment Clauses

DSM	Demand side management
TCRF	Transmission cost recovery factor (recovers transmission infrastructure improvement costs and changes in wholesale transmission charges)

Other Terms and Abbreviations

ADIT	Accumulated deferred income tax
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
ATRR	Annual transmission revenue requirement
C&I	Commercial and Industrial
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
IPP	Independent power producers
Moody's	Moody's Investor Services
NAV	Net asset value
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open access transmission tariff
PPA	Purchased power agreement
PTC	Production tax credit
ROE	Return on equity
ROU	Right-of-use
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
Standard & Poor's	Standard & Poor's Ratings Services
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

MW	Megawatts

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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, assumptions and other statements 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 securities filings (including SPS’ Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2018, and subsequent securities filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: 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; ability to recover costs from customers; reductions in our credit ratings and the costs 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; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

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. Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from the most directly comparable measure calculated and presented in accordance with GAAP.

SPS’ management uses non-GAAP measures internally for financial planning and analysis, for reporting of results to the Board of Directors, and when communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors’ understanding of our operating 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 Margins

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 recovery mechanisms, and as a result, changes in these expenses are offset in operating revenues. Management believes electric margin provides 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 operating and maintenance (O&M) expenses, demand side management (DSM) expenses, depreciation and amortization, and taxes (other than income taxes).

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PART 1 — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31	
	2019	2018
Operating revenues	$ 454.1	$ 447.2
Operating expenses		
Electric fuel and purchased power	230.9	253.9
Operating and maintenance expenses	72.4	66.1
Demand side management expenses	4.6	4.1
Depreciation and amortization	53.2	48.4
Taxes (other than income taxes)	18.5	17.6
Total operating expenses	379.6	390.1
Operating income	74.5	57.1
Other income (expense)	0.4	(0.7)
Allowance for funds used during construction — equity	10.3	3.4
Interest charges and financing costs		
Interest charges — includes other financing costs of $0.8 and $0.7 respectively	24.4	20.2
Allowance for funds used during construction — debt	(4.5)	(1.8)
Total interest charges and financing costs	19.9	18.4
Income before income taxes	65.3	41.4
Income taxes	11.2	8.3
Net income	$ 54.1	$ 33.1

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31,	
	2019	2018
Net income	$ 54.1	$ 33.1
Other comprehensive income		
Derivative instruments:		
Reclassification of losses to net income, net of tax of $0 and $0, respectively	—	0.1
Other comprehensive income	—	0.1
Comprehensive income	$ 54.1	$ 33.2

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31,	
	2019	2018
Operating activities		
Net income	$ 54.1	$ 33.1
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	53.8	48.5
Demand side management program amortization	—	0.4
Deferred income taxes	11.0	0.8
Allowance for equity funds used during construction	(10.3)	(3.4)
Changes in operating assets and liabilities:		
Accounts receivable	(1.3)	(11.4)
Accrued unbilled revenues	0.2	12.1
Inventories	(6.8)	6.0
Prepayments and other	(5.4)	1.4
Accounts payable	(9.3)	(12.0)
Net regulatory assets and liabilities	(1.2)	27.0
Other current liabilities	(16.7)	(4.9)
Pension and other employee benefit obligations	(15.9)	(7.9)
Other, net	0.3	0.2
Net cash provided by operating activities	52.5	89.9
Investing activities		
Utility capital/construction expenditures	(179.6)	(145.5)
Investments in utility money pool arrangement	—	(46.0)
Repayments from utility money pool arrangement	—	111.0
Net cash used in investing activities	(179.6)	(80.5)
Financing activities		
Proceeds from short-term borrowings, net	95.0	10.0
Proceeds from (repayments of) from issuance of long-term debt, net	(0.1)	—
Borrowings under utility money pool arrangement	100.0	1.0
Repayments under utility money pool arrangement	(62.0)	(1.0)
Capital contributions from parent	5.8	0.4
Dividends paid to parent	(55.1)	(26.8)
Net cash provided by (used in) financing activities	83.6	(16.4)
Net change in cash and cash equivalents	(43.5)	(7.0)
Cash and cash equivalents at beginning of period	44.0	10.9
Cash and cash equivalents at end of period	$ 0.5	$ 3.9
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (18.9)	$ (21.2)
Cash paid for income taxes, net	(4.9)	(4.0)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$ 68.5	$ 36.7
Inventory transfer additions in PPE	6.4	4.8
Operating lease right-of-use assets	548.3	—
Allowance for equity funds used during construction	10.3	3.4

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)

(amounts in millions, except share and per share data)

	March 31, 2019	Dec. 31, 2018
Assets		
Current assets		
Cash and cash equivalents	$ 0.5	$ 44.0
Accounts receivable, net	93.2	90.7
Accounts receivable from affiliates	3.4	10.5
Accrued unbilled revenues	114.3	114.5
Inventories	34.3	33.9
Regulatory assets	25.4	26.0
Derivative instruments	6.2	17.8
Prepaid taxes	14.2	14.2
Prepayments and other	16.1	10.7
Total current assets	307.6	362.3
Property, plant and equipment, net	6,088.5	5,946.4
Other assets		
Regulatory assets	364.6	366.2
Derivative instruments	15.0	15.8
Operating lease right-of-use assets	542.0	—
Other	5.0	5.1
Total other assets	926.6	387.1
Total assets	$ 7,322.7	$ 6,695.8
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 137.0	$ 42.0
Borrowings under utility money pool arrangement	38.0	—
Accounts payable	194.4	191.8
Accounts payable to affiliates	13.1	19.9
Regulatory liabilities	84.7	85.8
Taxes accrued	28.8	41.6
Accrued interest	26.1	25.8
Dividends payable	47.6	45.2
Derivative instruments	3.6	3.6
Other	49.4	28.3
Total current liabilities	622.7	484.0
Deferred credits and other liabilities		
Deferred income taxes	635.4	619.1
Regulatory liabilities	756.6	780.9
Asset retirement obligations	32.8	32.4
Derivative instruments	15.5	16.4
Pension and employee benefit obligations	76.4	92.4
Operating lease liabilities	515.8	—
Other	8.0	7.9
Total deferred credits and other liabilities	2,040.5	1,549.1
Commitments and contingencies		
Capitalization		
Long-term debt	2,126.3	2,126.1
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at March 31, 2019 and Dec. 31, 2018, respectively	—	—
Additional paid in capital	1,932.3	1,932.3
Retained earnings	602.3	605.7
Accumulated other comprehensive loss	(1.4)	(1.4)
Total common stockholder's equity	2,533.2	2,536.6
Total liabilities and equity	$ 7,322.7	$ 6,695.8

See Notes to Financial Statements

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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 Stockholders' Equity
Three Months Ended March 31, 2019 and 2018						
Balance at Dec. 31, 2017	100	$ —	$ 1,590.2	$ 541.6	$ (1.5)	$ 2,130.3
Net income				33.1		33.1
Other comprehensive income					0.1	0.1
Common dividends declared to parent				(33.3)		(33.3)
Balance at March 31, 2018	100	$ —	$ 1,590.2	$ 541.4	$ (1.4)	$ 2,130.2
Balance at Dec. 31, 2018	100	$ —	$ 1,932.3	$ 605.7	$ (1.4)	$ 2,536.6
Net income				54.1		54.1
Common dividends declared to parent				(57.5)		(57.5)
Balance at March 31, 2019	100	$ —	$ 1,932.3	$ 602.3	$ (1.4)	$ 2,533.2

See Notes to Consolidated Financial Statements

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 accounting principles generally accepted in the United States of America (GAAP), the financial position of SPS as of March 31, 2019 and Dec. 31, 2018; the results of its operations, including the components of net income and comprehensive income, and change in stockholder's equity for the three months ended March 31, 2019 and 2018; and its cash flows for the three months ended March 31, 2019 and 2018. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2019 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, 2018 balance sheet information has been derived from the audited 2018 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2018. 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, 2018, filed with the SEC on Feb. 22, 2019. 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, 2018, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for credit losses on receivables and certain other assets. The guidance requires use of a current expected loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASC Topic 326 is effective for interim and annual periods beginning on or after Dec. 15, 2019. SPS is currently evaluating the impact of adoption of the new standard on its financial statements.

Recently Adopted

Leases — In 2016, the FASB issued *Leases, Topic 842 (ASC Topic 842)*, which provides new accounting and disclosure guidance for leasing activities, most significantly requiring that operating leases be recognized on the balance sheet. SPS adopted the guidance on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions on whether agreements existing before the adoption date contain leases and whether existing leases are operating or finance leases; ASC Topic 842 refers to capital leases as finance leases.

Specifically for land easement contracts, SPS has elected the practical expedient provided by *ASU No. 2018-01 Leases: Land Easement Practical Expedient for Transition to Topic 842*, and as a result, only those easement contracts entered on or after Jan. 1, 2019 will be evaluated to determine if lease treatment is appropriate.

SPS also utilized the transition practical expedient offered by *ASU No. 2018-11 Leases: Targeted Improvements* to implement the standard on a prospective basis. As a result, reporting periods in the financial statements beginning Jan. 1, 2019 reflect the implementation of ASC Topic 842, while prior periods continue to be reported in accordance with *Leases, Topic 840 (ASC Topic 840)*. Other than first-time recognition of operating leases on its balance sheet, the implementation of ASC Topic 842 did not have a significant impact on SPS' financial statements. Adoption resulted in recognition of approximately $0.5 billion of operating lease ROU assets and current/noncurrent operating lease liabilities. See Note 9 for leasing disclosures.

3. Selected Balance Sheet Data

(Millions of Dollars)	March 31, 2019	Dec. 31, 2018
Accounts receivable, net		
Accounts receivable	$ 98.7	$ 96.3
Less allowance for bad debts	(5.5)	(5.6)
	$ 93.2	$ 90.7

(Millions of Dollars)	March 31, 2019	Dec. 31, 2018
Inventories		
Materials and supplies	$ 25.8	$ 25.7
Fuel	8.5	8.2
	$ 34.3	$ 33.9

(Millions of Dollars)	March 31, 2019	Dec. 31, 2018
Property, plant and equipment, net		
Electric plant	$ 7,287.2	$ 7,227.7
Construction work in progress	974.3	847.3
Total property, plant and equipment	8,261.5	8,075.0
Less accumulated depreciation	(2,173.0)	(2,128.6)
Total	$ 6,088.5	$ 5,946.4

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, 2019	Year Ended Dec. 31, 2018
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	38	—
Average amount outstanding	19	29
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	2.44%	1.96%
Weighted average interest rate at period end	2.44	N/A

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Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2019	Year Ended Dec. 31, 2018
Borrowing limit	$ 400	$ 400
Amount outstanding at period end	137	42
Average amount outstanding	86	30
Maximum amount outstanding	152	144
Weighted average interest rate, computed on a daily basis	2.69%	2.27%
Weighted average interest rate at period end	2.71	2.80

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. As of both March 31, 2019 and Dec. 31, 2018, 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.

As of March 31, 2019, SPS had the following committed credit facility available (in millions of dollars):

Credit Facility [(a)]	Outstanding [(b)]	Available
$ 400	$ 139	$ 261

(a) This credit facility expires in June 2021.

(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 facility. SPS had no direct advances on the credit facility outstanding as of March 31, 2019 and Dec. 31, 2018.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consists of the following:

	Three Months Ended	
(Millions of Dollars)	March 31, 2019	March 31, 2018
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 88.1	$ 80.0
C&I	205.8	195.8
Other	9.6	9.7
Total retail	303.5	285.5
Wholesale	84.8	93.2
Transmission	57.4	55.7
Other	1.0	7.5
Total revenue from contracts with customers	446.7	441.9
Alternative revenue and other	7.4	5.3
Total revenues	$ 454.1	$ 447.2

6. Income Taxes

Except to the extent noted below, Note 7 to the consolidated financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2018 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

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. The following reconciles such differences:

	Three Months Ended March 31,	
	2019	2018
Federal statutory rate	21.0%	21.0%
State tax (net of federal tax effect)	2.1	2.4
Increases (decreases) in tax from:		
Regulatory differences [(a)]	(4.6)	(2.7)
Tax credits (net)	(0.6)	(0.7)
Other (net)	(0.7)	—
Effective income tax rate	17.2%	20.0%

(a) Regulatory differences for income tax purposes primarily include the average rate assumption method (ARAM), ARAM deferral and AFUDC - Equity. ARAM is a method to flow back excess deferred taxes to customers. ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

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 Year(s)	Expiration
2009 - 2013	October 2019
2014 - 2016	September 2020
2017	September 2021

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of March 31, 2019, the case has been forwarded to the Office of Appeals and 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.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016. As of March 31, 2019 no adjustments have been proposed.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of March 31, 2019, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently no state income tax audits in progress.

Unrecognized Benefits — 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 the 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.

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Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	March 31, 2019	Dec. 31, 2018
Unrecognized tax benefit — Permanent tax positions	$ 3.1	$ 3.0
Unrecognized tax benefit — Temporary tax positions	1.6	1.5
Total unrecognized tax benefit	$ 4.7	$ 4.5

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	March 31, 2019	Dec. 31, 2018
NOL and tax credit carryforwards	$ (4.0)	$ (3.8)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $0.9 million and $0.8 million at March 31, 2019 and Dec. 31, 2018, respectively.

As the IRS Appeals and federal audit progress and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3.6 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)	March 31, 2019	Dec. 31, 2018
Receivable for interest related to unrecognized tax benefits at beginning of period	$ 0.7	$ 0.5
Interest income related to unrecognized tax benefits	—	0.2
Receivable for interest related to unrecognized tax benefits at end of period	$ 0.7	$ 0.7

No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2019 or Dec. 31, 2018.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The 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 NAVs.

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 generally utilize observable forward prices and volatilities, as well as observable pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to delivery locations for which pricing is relatively unobservable, 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 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, 2019, accumulated other comprehensive losses related to interest rate derivatives included $0.1 million 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.

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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 commodity FTRs:

(Amounts in Millions) [(a)]	March 31, 2019	Dec. 31, 2018
Megawatt hours of electricity	2.2	5.5

(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 March 31, 2019, one of the eight most significant counterparties for these activities, comprising $11.1 million or 24% 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 $9.0 million or 20% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. Two of these significant counterparties, comprising $4.4 million or 10% of this credit exposure, had credit quality less than investment grade, based on external analysis. Six of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were immaterial for the three months ended March 31, 2019 and 2018.

Changes in the fair value of FTRs resulting in pre-tax net gains of $6.3 million and $0.3 million recognized for the three months ended March 31, 2019 and 2018, respectively, 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 of an immaterial amount and losses of $0.5 million were recognized for the three months ended March 31, 2019 and 2018, 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, 2019 and 2018.

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Recurring Fair Value Measurements — SPS' derivative assets and liabilities measured at fair value on a recurring basis:

	March 31, 2019						Dec. 31, 2018					
	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	$ —	$ —	$ 3.1	$ 3.1	$ —	$ 3.1	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	$ 14.7
Total current derivative assets	$ —	$ —	$ 3.1	$ 3.1	$ —	3.1	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	14.7
PPAs [b]						3.1						3.1
Current derivative instruments						$ 6.2						$ 17.8
Noncurrent derivative assets												
PPAs [b]						15.0						15.8
Noncurrent derivative instruments						$ 15.0						$ 15.8
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	$ —
Total current derivative liabilities	$ —	$ —	$ —	$ —	$ —	—	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	—
PPAs [b]						3.6				.		3.6
Current derivative instruments						$ 3.6						$ 3.6
Noncurrent derivative liabilities												
PPAs [b]						15.5						16.4
Noncurrent derivative instruments						$ 15.5						$ 16.4

(a) SPS nets derivative instruments and related collateral in its balance sheet 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, 2019 and Dec. 31, 2018. At both March 31, 2019 and Dec. 31, 2018, 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, 2019 and 2018:

	Three Months Ended March 31,	
(Millions of Dollars)	2019	2018
Balance at Jan. 1	$ 14.7	$ 12.7
Purchases	3.9	0.7
Settlements	(6.5)	(10.4)
Net transactions recorded during the period:		
Net (losses) gains recognized as regulatory assets and liabilities	(9.0)	2.4
Balance at March 31	$ 3.1	$ 5.4

SPS recognizes transfers between fair value hierarchy 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, 2019 and 2018.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	March 31, 2019		Dec. 31, 2018	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 2,126.3	$ 2,220.4	$ 2,126.1	$ 2,139.8

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, 2019 and Dec. 31, 2018, and given the observability of the inputs, the fair values presented for long-term debt were assigned as Level 2.

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8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended March 31			
	2019	2018	2019	2018
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 2.2	$ 2.4	$ 0.2	$ 0.3
Interest cost [(a)]	5.0	4.6	0.4	0.4
Expected return on plan assets [(a)]	(7.2)	(7.1)	(0.5)	(0.6)
Amortization of prior service credit [(a)]	—	—	(0.1)	(0.1)
Amortization of net loss (gain) [(a)]	2.8	3.5	(0.1)	(0.2)
Net periodic benefit cost (credit)	2.8	3.4	(0.1)	(0.2)
(Costs) credits not recognized due to the effects of regulation	0.4	1.0	—	—
Net benefit cost (credit) recognized for financial reporting	$ 3.2	$ 4.4	$ (0.1)	$ (0.2)

[(a)] The components of net periodic cost other than the service cost component are included in the line item “other expense, net” in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2019, contributions of $150 million were made across four of Xcel Energy’s pension plans, of which $17 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2019.

9. Commitments and Contingencies

The following include commitments, contingencies and unresolved contingencies that are material to SPS’ financial position.

Legal

SPS is involved in various litigation matters that are being defended and handled 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 complex judgments about future events. Management maintains accruals for losses that are 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 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, arising from such current proceedings would have a material effect on SPS’ financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

SPP OATT Upgrade Costs — Under the SPP OATT, costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. 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 these previously unbilled charges was remanded to the FERC. In February 2019, after submission of additional briefs, the FERC reversed its 2016 decision and ordered SPP to refund the charges retroactively collected from its transmission customers, including SPS, related to periods before Sept. 2015. On April 1, 2019, several parties, including SPP, filed requests for rehearing. The timing of a FERC response to the rehearing requests is uncertain. The refunds are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC granted a rehearing for further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS’ complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

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 could result in an increase in the ATRR of $9.5 million per year, with $6 million allocated to SPS’ retail customers.

The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone. In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On October 31, 2018, the FERC issued an order accepting the proposed charges as of November 1, 2018. In December 2018, the FERC hosted a settlement hearing over the matter. A hearing will be ordered if a settlement is not reached.

SPS Filing to Modify Wholesale Transmission Rates - In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to the depreciation rates for transmission plant. The new formula rate would provide flow-back of “excess” ADIT resulting from the TCJA and recover certain wholesale regulatory commission expenses.

The proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total being recovered in SPP regional transmission rates. SPS proposed that the formula rate changes be effective February 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of February 1, 2019, subject to refund and settlement procedures. The first settlement conference is expected in April 2019.

Environmental

MGP, Landfill or Disposal Sites — SPS is currently investigating or remediating a MGP, landfill or other disposal site across its service territories, and these activities will continue through at least 2020. SPS accrued $0.1 million as of March 31, 2019 and Dec. 31, 2018, respectively. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of the costs incurred.

Leases

SPS evaluates a variety of contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. Under ASC Topic 842, adopted by SPS on Jan. 1, 2019, 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. Starting in 2019, the present value of future operating lease payments are 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 SPS' leases do not contain a readily determinable discount rate, and therefore the present value of future lease payments is calculated using the estimated incremental borrowing rate for similar borrowing periods. SPS has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments to the lessor, 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)	March 31, 2019
PPAs	$ 500.3
Other	48.0
Gross operating lease ROU assets	548.3
Accumulated amortization	(6.3)
Net operating lease ROU assets	$ 542.0

Given the impacts of accounting for regulated operations, and the resulting recognition of periodic expense at the amounts recovered in customer rates, cash expenditures for operating leases are consistent with recognized lease expense.

Components of lease expense:

(Millions of Dollars)	Three Months Ended March 31, 2019
Operating leases	
PPA capacity payments	$ 12.8
Other operating leases [(a)]	1.2
Total operating lease expense [(b)]	$ 14.0

(a) Includes short-term lease expense of $0.4 million.

(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.

Future commitments under operating leases as of March 31, 2019:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases
2019	$ 34.7	$ 2.5	$ 37.2
2020	46.2	3.4	49.6
2021	46.2	3.3	49.5
2022	46.2	3.4	49.6
2023	46.2	3.4	49.6
Thereafter	450.8	54.8	505.6
Total minimum obligation	670.3	70.8	741.1
Interest component of obligation	(176.0)	(23.1)	(199.1)
Present value of minimum obligation	494.3	47.7	542.0
Less current portion			(26.2)
Noncurrent operating lease liabilities			$ 515.8

Weighted-average discount rate	4.4%
Weighted-average remaining lease term in years	14.8

(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.

Future commitments under operating leases as of Dec. 31, 2018:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases
2019	$ 46.7	$ 5.2	$ 51.9
2020	46.2	5.2	51.4
2021	46.2	5.1	51.3
2022	46.2	5.1	51.3
2023	46.2	5.1	51.3
Thereafter	450.8	56.3	507.1

(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 2033.

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 it purchases. These specific PPAs create a variable interest in the associated IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs as of March 31, 2019 and Dec. 31, 2018, 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. These agreements 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. SPS'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.

Electric Margins

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).

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Management uses these non-GAAP financial measures to evaluate and provide details of SPS' core earnings and underlying performance.

Results of Operations

SPS' net income was approximately $54.1 million for the first quarter of 2019, compared with approximately $33.1 million for the same period in 2018. The increase was primarily due to a regulatory settlement which included tax reform in New Mexico (approximately $10 million), sales growth and higher AFUDC (related to the Hale County wind project), partially offset by higher O&M expenses, depreciation expense and interest expense.

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)	2019	2018
Electric revenues	$ 454.1	$ 447.2
Electric fuel and purchased power	(230.9)	(253.9)
Electric margin	$ 223.2	$ 193.3

Changes in electric margin:

(Millions of Dollars)	2019 vs 2018
Rate cases and regulatory proceedings (New Mexico)	$ 9.0
Purchased capacity costs	4.9
Wholesale transmission revenue, net	4.6
Non-fuel riders	3.2
Retail Sales growth	2.7
Retail rate increase (New Mexico)	1.3
Other, net	4.2
Total decrease in electric margin	$ 29.9

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses increased $6.3 million, or 9.5%, for the first quarter of 2019. Increase was driven by distribution costs and business systems expenses. Distribution expenses were higher due to storms, labor and overtime and business system costs increased as a result of service delivery and network costs.

Depreciation and Amortization — Depreciation and amortization increased $4.8 million, or 9.9% for the first quarter of 2019. The increase was primarily due to increased capital investments as well as accelerated depreciation at Tolk for the Texas jurisdiction.

Income Taxes — Income tax expense increased $2.9 million for the first quarter of 2019 compared with the same period in 2018. The increase was primarily driven by higher pretax income. This was partially offset by an increase in plant-related regulatory differences related to ARAM (a) (net of deferrals), an increase in non-plant accumulated deferred income tax amortization and an increase in other utility plant items. The ETR was 17.2% for the first quarter of 2019, compared with 20.0% for the same period in 2018. The lower ETR in 2019 is primarily due to the items referenced above. See Note 6 to the financial statements.

AFUDC, Equity and Debt — AFUDC increased $9.6 million for the first quarter of 2019. The increase was primarily due to an increase in wind construction projects, primarily the Hale Wind project.

Interest Charges — Interest charges increased $4.2 million, or 20.8%, for the first quarter of 2019. The increase was related to higher debt levels to fund capital investments and refinancing at higher interest rates.

Regulation

FERC and State Regulation — The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, asset transactions and mergers, accounting practices and certain other activities of SPS, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters.

Xcel Energy, which includes SPS, attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and Commodity Futures Trading Commission jurisdictions.

Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems.

While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations. Decisions by these regulators can significantly impact SPS' results of operations.

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Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					SPS (PUCT)
Rate Case	Electric	$54	August 2017	Pending	In November 2018, SPS filed an application with the PUCT requesting permission to recover $5.4 million in unbilled TCRF revenue from January 23, 2018 through June 9, 2018. Timing of a final order on this matter is uncertain.
					SPS (NMPRC)
Rate Case	Electric	$43	October 2017	Received	In February 2019, SPS and the NMPRC settled SPS' appeal to the NMSC regarding NMPRC's previous rate case order, including a $10.2 million refund of retroactive TCJA benefits. As a result, the NMPRC issued revised orders eliminating the retroactive refund and SPS reversed its previously recorded regulatory liability. The order also increased the ROE from 9.1% to 9.56% and the equity ratio from 51% to 53.97%, resulting in a prospective annual base rate increase of $4.5 million (incremental to $8.1 million approved in the initial order). New rates were effective March 11, 2019.

Wind Development — In 2018, the NMPRC and PUCT approved SPS' proposal to add 1,230 MW of new wind generation, including ownership of 1,000 MW.

In March 2018, the NMPRC approved SPS' petition to build and own Hale County, a 478 MW wind project in Texas, which is expected to be placed into service in June 2019. The NMPRC also approved Sagamore, a 522 MW wind project in New Mexico which is expected to be placed into service in late 2020. In May 2018, the PUCT approved SPS' petition to build and own Hale and Sagamore. Both projects qualify for 100% of PTCs. SPS' capital investment for these wind projects is expected to be approximately $1.6 billion. SPS is currently waiting to receive the transmission cost estimate from SPP for Sagamore, which is necessary to determine the final cost of the project before construction can start.

Texas State Right of First Refusal (ROFR) Request for Declaratory Order — In 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility the ROFR to construct new transmission facilities located in the utility's service area. The PUCT subsequently issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities. In January 2018, SPS and two other parties filed appeals in the Texas State District Court. In September 2018, the District Court affirmed the PUCT's ROFR order. SPS has filed an additional appeal.

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 chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of March 31, 2019, 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 the 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 that are being defended and handled in the ordinary course of business. Assessment of whether a loss is probable or is a reasonable possibility, and whether a loss or a range of loss is estimable, often involves a series of complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) damages sought are indeterminate, (2) proceedings are in the early stages or (3) 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.

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, 2018, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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Item 6 — EXHIBITS

* Indicates incorporation by reference
+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	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	001-03789	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	001-03789	3.02
10.01*+	Brett Carter's Sign-On Bonus Terms	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2019	001-03034	10.01
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	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101	The following materials from SPS' Quarterly Report on Form 10-Q for the quarter ended March 31, 2019 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Statements of Income, (ii) the Statements of Comprehensive Income (iii) the Statements of Cash Flows, (iv) the Balance Sheets, (v) Notes to Financial Statements, and (vi) document and entity information.			

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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 26, 2019

By: /s/ JEFFREY S. SAVAGE

Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Exhibit 31.01

CERTIFICATION

I, Ben Fowke, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 26, 2019

/s/ BEN FOWKE

Ben Fowke
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

Exhibit 31.02

CERTIFICATION

I, Robert C. Frenzel, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting

Date: April 26, 2019

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Exhibit 32.01

OFFICER CERTIFICATION

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Southwestern Public Service Company (SPS) on Form 10-Q for the quarter ended March 31, 2019, as filed with the SEC on the date hereof (Form 10-Q), each of the undersigned officers of SPS certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of SPS as of the dates and for the periods expressed in the Form 10-Q.

Date: April 26, 2019

/s/ BEN FOWKE
Ben Fowke
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to SPS and will be retained by SPS and furnished to the SEC or its staff upon request.

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Southwestern Public Service Company	End of 2018/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. 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.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees 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:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) 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

(d) 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:

a) 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

b) 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.)

Reference 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

e) 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 _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed 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 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.

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.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) 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 http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. 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

I. 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.

II. 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.

III 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.

IV. 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.

V. 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).

VI. 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.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. 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.

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 reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

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

I. 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.

II. 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:

(3) ’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;

(4) 'Person' means an individual or a corporation;

(5) '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;

(7) '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; ......

(11) "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

(a) 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. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be 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 salt 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. 1/3-Q:
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 2018/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 Jeffrey S. Savage	06 Title of Contact Person Sr. Vice Pres., Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 414 Nicollet Mall, Minnespolis, MN 55401	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(612) 330-5658	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Jeffrey S. Savage	Jeffrey S. Savage	04/18/2019
02 Title Senior Vice President, Controller		

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

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LIST OF SCHEDULES (Electric Utility) (continued)

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [ ] No annual report to stockholders is prepared		

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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.

Jeffrey S. Savage
Senior Vice President and Controller
414 Nicollet Mall
Minnespolis, MN 55401

1800 Larimer Street
Denver, CO 80202

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.

New Mexico, 1921

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

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 state 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...Enter the date when such independent accountant was initially engaged:
(2) [X] No

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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent 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 beneficiearies for whom trust was maintained, and purpose of the trust.

Southwestern Public Service Company (SPS) is a wholly-owned subsidiary of Xcel Energy, Inc.

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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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)
1	President	David T. Hudson	280,000
2	Chairman of the Board, Chief Executive Officer	Ben Fowke	160,896
3	Executive VP, Chief Financial Officer	Robert C. Frenzel	83,666
4	Executive VP	Kent T. Larson	77,231
5	Executive VP, General Counsel	Scott M. Wilensky	69,864
6	Senior VP, Chief Human Resources Officer	Darla Figoli	59,531
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14	Salaries represent Southwestern Public Service Co.		
15	allocation of officers' salaries greater than $50,000		
16	for the period of time that was served as an		
17	officer for Southwestern Public Service Co.		
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FOOTNOTE DATA

Schedule Page: 104 Line No.: 6 Column: b

Darla Figoli assumed a portion of Marvins responsibilities and was promoted on May 7th, 2018.

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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), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] 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	FERC Proceeding
1	See footnote.	
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Schedule Page: 106 Line No.: 1 Column: a

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.)	ER08-313-005 - 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.)
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.)	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 - 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.)
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.	ER10-2075 - 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.)
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.)	ER11-114 - 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.)
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.)	ER11-3505 - 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.)
Second Revised FERC Rate Schedule No. 102, Tariff ID 1000 (Public Service Company of New Mexico)	ER10-260 - 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.)
FERC Electric Rate Schedule No. 102, Tariff ID 1000	ER11-3442 - Revised Formula Rate Template for

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(Public Service Company of New Mexico)	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.)
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.)	EL05-19-000, et al., and ER05-168-000, et al. 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.)
FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	ER11-4082 - 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.)
FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	ER11-4083 - 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.)
FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	ER11-4084 - 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.)
FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	ER11-4085 - 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.)
SPS FERC Electric Rate Schedule Second Revised No. 118, Tariff ID 1000. (Wholesale Full Requirements Service to Cap Rock Energy Corporation, now Sharyland Utilities.)	EL05-19-000, et al., and ER05-168-000, et al. 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.)
FERC Electric Rate Schedule No. 118, Tariff ID 1000 (Sharyland Utilities)	ER11-2921 - 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.)
FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	EL05-19-000, ER05-168-000 and ER06-274-000 - 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.)
FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER10-1426 - Revised Formula Rate Template for Partial Requirements Service to Golden Spread

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	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.)
FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER11-3228 - 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.)
First Revised FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER10-515 - 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.)
FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER11-3598 - 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.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative, Inc.)	ER12-1122 - 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.)
FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	ER13-1451 - 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.)
FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	ER13-1452 - 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.)
FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	ER13-1453 - 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.)
FERC Electric Rate Schedule No. 118. Tariff ID 1000 (Sharyland Utilities)	ER13-1454 - 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.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER13-1455 - Revised Formula Rate Template for Full Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20130510-5099.)

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	Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3022.)
FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER13-1456 - 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.)
FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	ER13-1458 - 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.)
FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	ER14-186 - 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.)
FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	ER14-187 - 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.)
FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	ER14-188 - 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.)
FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	ER14-189 - 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.)
FERC Electric Rate Schedule No. 118, Tariff ID 1000 (Sharyland Utilities)	ER14-190 - 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.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER14-192 - 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.)
FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER14-191 - 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.)

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FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER14-2921 - 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.)
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)	ER14-2923 - 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.)
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)	ER15-561 - 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.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER15-562 - 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.)
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)	ER-15-949 - 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).
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	EL05-19, ER05-168, ER06-274, EL05-151, EL12-59, EL13-78, EL15-8, ER14-192, and ER15-949 - 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.

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FOOTNOTE DATA

Municipal Power Agency)	al. (Accession No 20151029-3063).
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.)	ER16-236 - 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.)
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.)	ER16-512 - 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).
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)	ER16-520 - 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).
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER16-920 - 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).
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.)	ER16-1420 - 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).

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FOOTNOTE DATA

	Letter order accepting filing issued June 7, 2016, effective April 16, 2016 (Accession No. 20160607-3006).
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)	ER16-1431 - 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).
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.)	ER16-2597 and ER16-2598 - 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).
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)	ER17-236 and ER17-238 - 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).
FERC Electric Rate Schedule No. 136, Tariff ID 1001 (Tri-County Electric Cooperative, Inc.)	ER17-267 - 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).
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	ER18-228 - 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.

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FOOTNOTE DATA

Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency, Tri-County Electric Cooperative, Inc.)	(Accession No. 20171101-5294). Offer of Settlement filed January 7, 2019 (Accession No. 20190107-5000).
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.)	ER18-1521 - 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).
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.)	ER18-2410 - 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).
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.)	ER18-2319 - 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).
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.)	ER19-404 - 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

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FOOTNOTE DATA

	(Accession No. 20181127-5093).
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.)	ER19-675 - 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). (Accession No. 20181221-5281). Order accepting and suspending proposed tariff revisions effective August 1, 2019 and establishing hearing and Settlement Judge procedures (Accession No. 20190228-3016).

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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)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20181203-5188	12/03/2018	ER08-313-000	Informational Filing: Annual Update of	Xcel Energy Operating Companies
2				Transmission Formula Rate, under	FERC Electric Tariff, Second Revised
3				ER08-313, et al.	Volume No. 1 - Attachment O - SPS
4					Southwestern Public Service
5					Company Formulaic Rates
6					
7	20180524-5099	05/25/2017	EL05-19-000	Informational Filing: Annual Update of	FERC Electric Rate Schedule No. 114
8			ER05-168-000	Rates for Service to Central Valley	FERC Electric Rate Schedule No. 115
9			ER10-515-000	Cooperative Inc., Farmers Electric	FERC Electric Rate Schedule No. 116
10			ER17-267-000	of New Mexico Inc., Lea County	FERC Electric Rate Schedule No. 117
11				Cooperative Inc., Roosevelt County	FERC Electric Rate Schedule No. 118
12				Cooperative Inc., Tri-County Electric	FERC Electric Rate Schedule No. 136
13				Inc., and West Texas Municipal Power	FERC Electric Rate Schedule No. 137
14				(The Annual Update informational filing	
15				the calculation of estimated rates for	
16				these customers for the upcoming rate	
17				July 1, 2018 to June 30, 2019).	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Page 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

The following important changes have been accumulated during 2018:

1. Franchise

The following franchise renewals occurred during 2018:

City	State	Consideration	Expiration
Lockney	TX	5% of Electric Revenue	03/10/2028
Borger	TX	5% of Electric Revenue	04/01/2028
Friona	TX	5% of Electric Revenue	05/11/2028

2. Acquisitions

None

3. Purchase or sale of an operating system

None

4. Important leaseholds acquired or given, assigned or surrendered

None

5. Important extension or reduction of transmission or distribution system

None

6. Obligations incurred as a result of securities or assumption of liabilities

See Note 3 of the Financial Statements on page 123 for disclosures regarding short-term borrowings, long-term debt and other financing instruments.

7. Changes in articles of incorporation and amendments to charter

None

8. Wage scale changes

Union employees - Increase of 2.50 percent effective November 1, 2018.

Non-Union employees - Merit base increase of 3.00 percent effective March 16, 2018.

9. Legal proceedings

See Note 8 of the Financial Statements on page 123 for further information on material

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

legal proceedings.

10. Other materially important transactions with associates

None

11. (Reserved)

12. Important changes

None

13. Changes in officers, directors, major security holders and voting powers

Effective March 1, 2018, Marvin E. McDaniel, Jr. resigned as Executive Vice President, Group President of Utilities and Chief Administrative Officer.

Effective March 1, 2018, David L. Eves, was elected Executive Vice President and Group President of Utilities.

Effective May 7, 2018, Darla Figoli was elected Senior Vice President, Chief Human Resource Officer.

Effective Sept. 1, 2018, Brian Van Abel resigned as Vice President, Treasurer and was elected Senior Vice President of Finance and Corporate Development.

Effective Sept. 1, 2018, Sarah W. Soong was elected as Vice President, Treasurer.

14. Cash management programs

N/A as proprietary capital ratio is greater than 30%.

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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)	200-201	7,224,210,989	6,760,946,178
3	Construction Work in Progress (107)	200-201	849,058,368	351,875,295
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		8,073,269,357	7,112,821,473
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,315,941,276	2,218,081,272
6	Net Utility Plant (Enter Total of line 4 less 5)		5,757,328,081	4,894,740,201
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,757,328,081	4,894,740,201
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,422,200	4,424,375
19	(Less) Accum. Prov. for Depr. and Amort. (122)		389,211	430,952
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		2,170,934	1,828,960
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		15,794,752	18,953,704
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		21,998,675	24,776,087
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		43,254,838	0
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		100,600	100,600
38	Temporary Cash Investments (136)		678,238	10,770,508
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		61,446,320	63,399,878
41	Other Accounts Receivable (143)		49,470,885	36,271,696
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,614,497	6,347,912
43	Notes Receivable from Associated Companies (145)		0	65,000,000
44	Accounts Receivable from Assoc. Companies (146)		10,490,267	1,297,341
45	Fuel Stock (151)	227	8,202,732	14,215,177
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	20,810,571	21,283,101
49	Merchandise (155)	227	188,238	244,327
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	4,684,859	4,690,172

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

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)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		2,961,246	7,508,140
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		674,447	0
60	Rents Receivable (172)		701,102	699,008
61	Accrued Utility Revenues (173)		114,488,630	129,803,837
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		33,612,156	34,835,830
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		15,794,752	18,953,704
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		330,355,880	364,817,999
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		20,388,992	18,313,098
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	360,121,131	352,722,115
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	3,849,997
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	10,509,661	21,922,318
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		22,671,006	23,471,526
82	Accumulated Deferred Income Taxes (190)	234	101,395,180	112,368,460
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		515,085,970	532,647,514
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,624,768,606	5,816,981,801

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FOOTNOTE DATA

Schedule Page: 110 Line No.: 52 Column: c

The balance is comprised of Texas Renewable Energy Credit Allowances of $4,684,859.

Schedule Page: 110 Line No.: 52 Column: d

The balance is comprised of Texas Renewable Energy Credit allowances of $4,690,172.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
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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)	250-251	100	100
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		362,132,084	362,132,084
7	Other Paid-In Capital (208-211)	253	1,579,192,171	1,237,143,647
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	9,033,435	9,033,435
11	Retained Earnings (215, 215.1, 216)	118-119	605,725,195	541,588,360
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-1,390,415	-1,466,468
16	Total Proprietary Capital (lines 2 through 15)		2,536,625,700	2,130,364,288
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,800,000,000	750,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	350,000,000	1,100,000,000
22	Unamortized Premium on Long-Term Debt (225)		9,036,717	9,339,908
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		12,577,728	11,085,757
24	Total Long-Term Debt (lines 18 through 23)		2,146,458,989	1,848,254,151
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,369,289	198,666
29	Accumulated Provision for Pensions and Benefits (228.3)		88,954,228	87,113,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		609,192	768,709
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		16,383,835	19,948,559
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		32,422,529	28,524,376
35	Total Other Noncurrent Liabilities (lines 26 through 34)		139,739,073	136,553,310
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		42,000,000	0
38	Accounts Payable (232)		198,349,988	218,223,330
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		19,853,351	22,577,089
41	Customer Deposits (235)		6,975,006	7,439,263
42	Taxes Accrued (236)	262-263	42,497,226	35,523,161
43	Interest Accrued (237)		25,766,686	23,210,163
44	Dividends Declared (238)		45,159,800	26,753,125
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Southwestern Public Service Company	(1) [x] An Original (2) [ ] A Resubmission	04/18/2019	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

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)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		5,034,489	4,828,210
48	Miscellaneous Current and Accrued Liabilities (242)		2,184,608	2,269,255
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		19,948,560	23,513,285
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		16,383,835	19,948,559
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		391,385,879	344,388,322
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	3,948
57	Accumulated Deferred Investment Tax Credits (255)	266-267	157,285	209,706
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	13,239,647	17,240,429
60	Other Regulatory Liabilities (254)	278	678,989,897	656,524,077
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	1,127,055	1,155,476
63	Accum. Deferred Income Taxes-Other Property (282)		634,112,655	599,458,671
64	Accum. Deferred Income Taxes-Other (283)		82,932,426	82,829,423
65	Total Deferred Credits (lines 56 through 64)		1,410,558,965	1,357,421,730
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,624,768,606	5,816,981,801

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 112   Line No.: 18   Column: d

The balance as of 12-31-17 is understated by $750M.

Schedule Page: 112   Line No.: 21   Column: d

The balance as of 12-31-17 is overstated by $750M.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin 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.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,895,673,382	1,877,142,738		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,258,033,746	1,247,026,971		
5	Maintenance Expenses (402)	320-323	59,743,150	64,878,811		
6	Depreciation Expense (403)	336-337	168,450,121	155,346,716		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	1,943	-1,687,758		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	27,401,099	24,458,373		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		8,751,052	7,159,179		
13	(Less) Regulatory Credits (407.4)		9,078,986	-12,544,481		
14	Taxes Other Than Income Taxes (408.1)	262-263	67,974,652	66,645,934		
15	Income Taxes - Federal (409.1)	262-263	15,232,455	-21,792,457		
16	- Other (409.1)	262-263	2,554,065	-15,815,723		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	95,466,283	216,832,636		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	74,143,754	113,200,216		
19	Investment Tax Credit Adj. - Net (411.4)	266	-52,421	-132,598		
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)		11,863	860,861		
23	Losses from Disposition of Allowances (411.9)		1,335,403	1,900,079		
24	Accretion Expense (411.10)		1,530,270	1,537,662		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,623,187,215	1,644,841,229		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		272,486,167	232,301,509		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. 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.
11 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 purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. 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.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,895,673,382	1,877,142,738					2
						3
1,258,033,746	1,247,026,971					4
59,743,150	64,878,811					5
168,450,121	155,346,716					6
1,943	-1,687,758					7
27,401,099	24,458,373					8
						9
						10
						11
8,751,052	7,159,179					12
9,078,986	-12,544,481					13
67,974,652	66,645,934					14
15,232,455	-21,792,457					15
2,554,065	-15,815,723					16
95,466,283	216,832,636					17
74,143,754	113,200,216					18
-52,421	-132,598					19
						20
						21
11,863	860,861					22
1,335,403	1,900,079					23
1,530,270	1,537,662					24
1,623,187,215	1,644,841,229					25
272,486,167	232,301,509					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		272,486,167	232,301,509		
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)		202,737	267,465		
34	(Less) Expenses of Nonutility Operations (417.1)		210,409	184,991		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		826,207	2,388,075		
38	Allowance for Other Funds Used During Construction (419.1)		19,102,029	9,310,207		
39	Miscellaneous Nonoperating Income (421)		107,977	768,063		
40	Gain on Disposition of Property (421.1)		6,794	97,647		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		20,035,335	12,646,466		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		13,700	69,537		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,100,873	755,572		
46	Life Insurance (426.2)		-34,743	-59,774		
47	Penalties (426.3)		32,815	349,701		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		504,416	811,969		
49	Other Deductions (426.5)		208,972	208,691		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,826,033	2,135,696		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	22,400	30,496		
53	Income Taxes-Federal (409.2)	262-263	-2,444,727	1,764,114		
54	Income Taxes-Other (409.2)	262-263	-28,773	21,493		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,041,319	2,080,616		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	731,155	1,342,058		
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)		-140,936	2,554,661		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		17,350,238	7,956,109		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		79,516,495	81,903,249		
63	Amort. of Debt Disc. and Expense (428)		1,169,096	1,251,691		
64	Amortization of Loss on Reaquired Debt (428.1)		807,614	377,187		
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)		1,071,156	458,731		
68	Other Interest Expense (431)		2,910,785	2,437,842		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,958,966	5,384,186		
70	Net Interest Charges (Total of lines 62 thru 69)		76,516,180	81,044,514		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		213,320,225	159,213,104		
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)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		213,320,225	159,213,104		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 4 Column: c

Includes $17,700,000 of demand-side management program expenses.

Schedule Page: 114 Line No.: 4 Column: d

Includes $15,525,000 of demand-side management program expenses.

Schedule Page: 114 Line No.: 12 Column: c

NM RPS Rider Amort	$7,348,258
TX Restruct Recoverable Meter	34,898
NM Z2 Amort	135,907
TX Z2 Amort	1,231,989
	$8,751,052

Schedule Page: 114 Line No.: 12 Column: d

NM RPS Rider Amort	$7,124,281
TX Restruct Recoverable Meter	34,898
	$7,159,179

Schedule Page: 114 Line No.: 13 Column: c

ARO Reg Credits Electric	$ 1,532,213
Amort of Inc Capital RL	53,949
NM Lg Cust Cap Amort	2,109,921
Retail Recovery of Credit Dist. - Funded	(948)
Retail Recovery of PTP Revenue Clawback	527
Retail Recovery Z2 DAUC	36,509
TX 47527 Revenue Accrual	5,346,815
	$ 9,078,986

Schedule Page: 114 Line No.: 13 Column: d

ARO Reg Credits Electric	$ (150,096)
Amort of Inc Capital RL	53,949
NM Lg Cust Cap Amort	1,754,560
Retail Recovery of Credit Dist. - Funded	950
Retail Recovery of PTP Revenue Clawback	(103,968)
Retail Recovery of Z2 DAUC	124
TX 45524 Settlement	(14,100,000)
	$ (12,544,481)

Schedule Page: 114 Line No.: 22 Column: c

Gain-Disposition of SO2 Allowances	$ 62
SO2 New Mexico Retail Sharing	(18)
SO2 Texas Retail Sharing	(35)
SO2 Amortization	5,439
Gain-Disposition of REC Allowances	6,415
	$ 11,863

Schedule Page: 114 Line No.: 22 Column: d

Gain-Disposition of SO2 Allowances	$ 60
SO2 New Mexico Retail Sharing	(14)
SO2 Texas Retail Sharing	(34)
Gain-Disposition of REC Allowances	860,849
	$ 860,861

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 46 Column: c

Income on Company owned life insurance.

Schedule Page: 114 Line No.: 46 Column: d

Income on Company owned life insurance

Schedule Page: 114 Line No.: 53 Column: c

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.

Schedule Page: 114 Line No.: 54 Column: c

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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		541,588,360	486,763,276
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4			-90	259,880
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-90	259,880
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		213,320,225	159,213,104
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-149,183,300	(104,647,900)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-149,183,300	(104,647,900)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		605,725,195	541,588,360
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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)
41				
42				
43				
44				
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)		605,725,195	541,588,360
	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				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 118 Line No.: 4 Column: c

On November 15, 2018 the FERC granted Edison Electric Institute's request for blanket approval for public utilities and centralized service companies to use Account 439 to record reclassifications of "accumulated other comprehensive income" to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act (Docket No. AC18-59-000).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Instruction 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)	213,320,225	159,213,104
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	170,024,867	155,239,154
5	Amortization of Premium, Discount and Debt Expense	1,976,710	1,628,878
6	Amortization of Regulatory Assets and Liabilities	-327,935	19,703,660
7	Amortization of Software and Others	27,401,099	24,458,373
8	Deferred Income Taxes (Net)	23,633,381	104,370,978
9	Investment Tax Credit Adjustment (Net)	-52,421	-132,598
10	Net (Increase) Decrease in Receivables	-15,472,941	-10,485,304
11	Net (Increase) Decrease in Inventory	-16,002,541	-2,656,573
12	Net (Increase) Decrease in Allowances Inventory	5,313	728,912
13	Net Increase (Decrease) in Payables and Accrued Expenses	5,745,985	19,482,578
14	Net (Increase) Decrease in Other Regulatory Assets	9,940,397	16,477,231
15	Net Increase (Decrease) in Other Regulatory Liabilities	26,074,733	5,757,878
16	(Less) Allowance for Other Funds Used During Construction	19,102,029	9,310,207
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Change in Accrued Utility Revenues	15,315,207	-10,385,692
19	Change in Other Current Assets and Liabilities	-7,835,715	8,718,134
20	Net Derivative Losses	63,162	63,179
21	Change in Other Noncurrent Liabilities and Deferred Amounts	11,576,389	-12,416,460
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	446,283,886	470,455,225
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,039,880,283	-559,865,335
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-82,100	
30	(Less) Allowance for Other Funds Used During Construction	-19,102,029	-9,310,207
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,020,860,354	-550,555,128
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
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	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
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: Miscellaneous Other Investing Activities Rabbi Trust		-493,082
54	Other: Investments in Utility Money Pool	-285,000,000	-142,000,000
55	Other: Repayments from Utility Money Pool	350,000,000	77,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-955,860,354	-616,048,210
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	294,959,848	442,338,292
62	Preferred Stock		
63	Common Stock		
64	Other: Capital Contributions by Parent	336,587,000	143,659,163
65	Other: Borrowings Under Utility Money Pool	595,000,000	335,000,000
66	Net Increase in Short-Term Debt (c)	42,000,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,268,546,848	920,997,455
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-271,612,618
74	Preferred Stock		
75	Common Stock		
76	Other: Repayment of Utility Money Pool	-595,000,000	-335,000,000
77	Other (Taxes Paid - Share based awards)	-31,187	
78	Net Decrease in Short-Term Debt (c)		-50,000,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-130,776,625	-108,765,125
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	542,739,036	155,619,712
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	33,162,568	10,026,727
87			
88	Cash and Cash Equivalents at Beginning of Period	10,871,108	844,381
89			
90	Cash and Cash Equivalents at End of period	44,033,676	10,871,108

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 6 Column: b

2018

Demand-side management program expenses	$ 1,673,346
Other amortization (credits), net	(2,001,281)
	$ (327,935)

Schedule Page: 120 Line No.: 6 Column: c

Demand-side management program expenses	$ 1,673,347
Other amortization (credits), net	18,030,313
	$ 19,703,660

Schedule Page: 120 Line No.: 10 Column: b

Includes provision for bad debts of $4,938,000.

Schedule Page: 120 Line No.: 10 Column: c

Includes provision for bad debts of $5,090,886.

Schedule Page: 120 Line No.: 13 Column: b

2018

Gain on Sale of PPE	$ (6,905)
Payables and accrued expenses	5,752,890
	$ 5,745,985

Schedule Page: 120 Line No.: 13 Column: c

2017

Gain on Sale of PPE	$ (28,110)
Payables and accrued expenses	19,510,688
	$ 19,482,578

Schedule Page: 120 Line No.: 21 Column: b

2018

Change in Accum Provision for Pension & Benefits	$ 1,841,228
Change in Miscellaneous Deferred Debits/Credits	5,219,983
Change in Other	4,515,178
	$ 11,576,389

Schedule Page: 120 Line No.: 21 Column: c

Change in Accum Provision for Pension & Benefits	$ (22,331,408)
Change in Miscellaneous Deferred Debits/Credits	9,836,880
Change in Other	78,068
	$ (12,416,460)

Schedule Page: 120 Line No.: 90 Column: b

2018

Cash (131)	$

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

		43,254,838
Working Fund (135)	$	100,600
Temporary Cash Investments (136)		678,238
	$	44,033,676

Schedule Page: 120 Line No.: 90 Column: c

Working Fund (135)	$	100,600
Temporary Cash Investments (136)		10,770,508
	$	10,871,108

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies

General — Southwest Public Service Company (SPS) is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity. SPS is subject to regulation by the Federal Regulatory Energy Commission (FERC) and state utility commissions.

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 Federal Energy Regulatory Commission (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:

(Thousands of Dollars)	**12/31/2018**
Balance Sheet:	
Net utility plant	$ 189,067
Current assets	31,947
Current liabilities	92,578
Other long-term assets	(149,999)
Long-term debt and other long-term liabilities	(21,563)

Statement of Income:

Operating revenues	$	37,473
Operating expenses		(1,738)
Other income and deductions		(1,289)

Use of Estimates — SPS uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, asset retirement obligations (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 when actual amounts can be determined. Those 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 (OCI), are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- 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 or cash flows.

See Note 2 for further information.

Income Taxes — SPS accounts for income taxes using the asset and liability method, which requires 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 the tax 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 its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

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 (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.

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.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Recognition of changes in uncertain tax positions are reflected as a component of income tax.

SPS reports interest and penalties related to income taxes within the other income and interest charges in the statements of income. Interest and penalties are recorded separately to their respective line items in the income statement.

Xcel Energy Inc. and its subsidiaries, including SPS, files 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 Notes 2 and 6 for further information.

Utility Plant and Depreciation — Utility Plant 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. 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 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. Depreciation expense, expressed as a percentage of average depreciable property, was 2.9% in 2018 and 2.8% in 2017.

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. SPS also recovers through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

See Note 9 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 8 for further information.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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. If an environmental expense is related to facilities currently in use, such as 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 (PRPs) 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 9 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 on a systematic basis 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). Revenues and charges for energy transacted through SPP are recorded based upon our evaluation each hour as to whether we are a net seller or a net buyer based upon total volumes in the real time market. If SPS is a net seller, the transaction is recorded on a gross basis in electric revenues and cost of sales. If SPS is a net buyer, the transaction is recorded on a net basis in cost of sales.

See Note 4 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.

Inventory — Inventory is recorded at average cost.

Commodity Trading Operations — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of the commodity trading margins for SPS are apportioned to Northern States Power Company, a Minnesota corporation (NSP-Minnesota) and Public Service Company of Colorado (PSCo). Commodity trading activities are not associated with energy produced from SPS' 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 7 for further discussion.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

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 net asset values (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 7 and 8 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 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 7 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 under GAAP. 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. When certain criteria are met, such as 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 the total amount collected and the 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 in the period earned.

See Note 4 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 demand side management (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 plus 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 purposes is recorded as electric fuel and purchased power expense. SPS reduces recoverable fuel costs for the cost of RECs and records that cost as a regulatory asset when the amount is 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.

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. Operating results from the regulated electric utility segment serve as the primary basis for the chief operating decision maker to evaluate the performance of SPS.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2018 up to Feb. 22, 2019, the date SPS' GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 18, 2019. These financial statements contain all necessary 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, 2018	Dec. 31, 2017
Regulatory Assets			
Pension and retiree medical obligations	Various	$ 232.0	$ 235.8
Excess deferred taxes – Tax Cuts and Jobs Act (TCJA)	Various	55.8	44.7
Recoverable deferred taxes on AFUDC recorded in plant	Plant lives	27.9	23.9
Net AROs [(a)]	Plant lives	25.7	24.2
Conservation programs [(b)]	One to two years	0.1	1.9
Other	Various	18.6	22.2
Total regulatory assets		$ 360.1	$ 352.7

(a) Includes amounts recorded for future recovery of AROs.

(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

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Components of regulatory liabilities:

(Millions of Dollars)	Remaining Amortization Period	Dec. 31, 2018	Dec. 31, 2017
Regulatory Liabilities			
Deferred income tax adjustments and TCJA refunds [a]	Various	$ 571.9	$ 568.6
Gain from asset sales	Various	2.4	2.5
Deferred electric energy costs	Less than one year	56.6	48.5
Other	Various	48.1	36.9
Total regulatory liabilities		$ 679.0	$ 656.5

(a) Includes the revaluation of recoverable/regulated plant accumulated deferred income tax (ADIT) and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes the fair value of certain long-term purchased power agreements (PPAs) used to meet energy capacity requirements.

At Dec. 31, 2018 and 2017, approximately $48 million and $64 million, respectively, of SPS' regulatory assets represented past expenditures not earning a return. Amounts primarily related to formula rates, losses on reacquired debt and certain rate case expenditures.

3. Borrowings and Other Financing Instruments

Short-Term Borrowings

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)		Year Ended Dec. 31 2018	2017
Borrowing limit	$	$ 100	$ 100
Amount outstanding at period end		—	—
Average amount outstanding		29	13
Maximum amount outstanding		100	100
Weighted average interest rate, computed on a daily basis	%	1.96 %	1.12 %
Weighted average interest rate at end of period		N/A	N/A

Commercial Paper — SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility.

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Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	2018	2017
Borrowing limit	$ 400	$ 400
Amount outstanding at period end	42	—
Average amount outstanding	30	69
Maximum amount outstanding	144	176
Weighted average interest rate, computed on a daily basis	2.27 %	1.13 %
Weighted average interest rate at end of period	2.80	NA

Letters of Credit — SPS may use letters of credit, typically with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2018 and 2017, there were $2 million and $3 million of letters of credit outstanding, respectively, under the credit facility. Amounts approximate their fair value.

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)		Amount Facility May Be Increased (millions)	Additional Periods For Which a One-Year Extension May Be Requested (b)
2018	2017		
46%	46%	$50	2

(a) The SPS 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 will 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, 2018, SPS was in compliance with all financial covenants.

SPS had the following committed credit facilities available as of Dec. 31, 2018.

Credit Facility (a)	Drawn (b)	Available
$400	$44	$356

(a) This credit facility matures in June 2021.

(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, 2018 and 2017.

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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:

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Mortgage bonds	2024 - 2048	3.30% - 4.50%	3.30% - 4.50%	$ 1,800	$ 1,500
Unsecured senior notes	2033 - 2036	6.00%	6.00% - 8.75%	350	350
Unamortized discount				(4)	(2)
Unamortized debt issuance cost				(20)	(18)
Current maturities				—	—
Total long term debt				$ 2,126	$ 1,830

During the next five years, SPS has no long term debt maturities.

Deferred Financing Costs — Deferred financing costs of approximately $20 million and $18 million, net of amortization, are presented as deferred debits at Dec. 31, 2018 and 2017, respectively. SPS is amortizing these financing costs over the remaining maturity periods of the related debt.

2018 financings:

Amount	Financing Instrument	Interest Rate	Maturity Date
$300 million	First mortgage bonds	4.40 %	Nov 15, 2048

2017 financings:

Amount	Financing Instrument	Interest Rate	Maturity Date
$450 million	First mortgage bonds	3.70 %	Aug 15, 2047

***Capital Stock* —** SPS has the following preferred stock:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2018 and 2017
SPS	10,000,000	1.00	0

***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 commission imposes the most restrictive dividend limitations.

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Requirements and actuals as of Dec. 31, 2018:

Equity to Total Capitalization Ratio - Required Range		Equity to Total Capitalization Ratio - Actual (a)
Low	High	2018
45.0 %	55.0 %	54.4 %

(a) SPS excludes short-term debt.

	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
	2018	2018	2018
SPS (a)	$ 605.7million	$ 4.7billion	N/A

(a) SPS may not pay a dividend that would cause it to lose its investment grade bond rating.

4. Preferred Stock

SPS has authorized the issuance of preferred stock.

Preferred Shares Authorized	Par Value	Preferred Shares Outstanding
10,000,000	$ 1.00	None

5. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy (which includes SPS), generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for net operating losses (NOLs) arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and,
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Xcel Energy estimated the effects of the TCJA, which have been reflected in the financial statements.

Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of Internal Revenue Service (IRS) requirements and past regulatory treatment.

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Estimated impacts of the new tax law for SPS in December 2017 included:

- $426 million ($559 million grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over the average remaining life of the related property;
- $45 million and $28 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and,
- $8 million of total estimated income tax benefit related to the federal tax reform implementation, and a $2 million reduction to net income related to the allocation of Xcel Energy Services Inc.'s tax rate change on its deferred taxes.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Audit **—** 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 Year(s)	Expiration
2009 – 2014	October 2019
2015	September 2019
2016	September 2020
2017	September 2021

In 2012, the Internal Revenue Services (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. SPS did not accrue any income tax benefit related to this adjustment. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's Net Operating Loss (NOL) and Effective Tax Rate (ETR). Xcel Energy filed a protest with the IRS. As of Dec. 31, 2018, the case has been forwarded to the Office of Appeals and 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.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016, however no adjustments have been proposed.

State Audits **—** SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2018, SPS' earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2010. There are currently no state income tax audits in progress.

Unrecognized Tax Benefits **—** 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 the 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)	Dec. 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 3.0	$ 2.3
Unrecognized tax benefit — Temporary tax positions	1.5	2.0
Total unrecognized tax benefit	$ 4.5	$ 4.3

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Changes in unrecognized tax benefits:

(Millions of Dollars)	2018	2017
Balance at Jan. 1	$ 4.3	$ 28.7
Additions based on tax positions related to the current year	0.6	0.9
Reductions based on tax positions related to the current year	(0.1)	(0.6)
Additions for tax positions of prior years	0.1	1.3
Reductions for tax positions of prior years	(0.3)	(19.9)
Settlements with taxing authorities	(0.1)	(6.1)
Balance at Dec. 31	$ 4.5	$ 4.3

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (3.8)	$ (5.9))

As the IRS Appeals and federal audit progress and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3.6 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)	2018	2017
Receivable (payable) for interest related to unrecognized tax benefits at Jan 1	$ 0.5	$ (0.9)
Interest income related to unrecognized tax benefits recorded during the year	0.2	1.4
Receivable for interest related to unrecognized tax benefits at Dec. 31	$ 0.7	$ 0.5

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2018, or 2017

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)	2018	2017
Federal NOL carryforward	$ —	$ 127.6
Federal tax credit carryforwards	7.4	6.3
State NOL carryforwards	2.9	40.5

Federal carryforward periods expire between 2021 and 2038 and state carryforward periods expire between 2021 and 2036.

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.

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Effective income tax rate for years ended Dec. 31:

	2018	2017 [(a)]
Federal statutory rate	21.0 %	35.0 %
State income tax on pretax income, net of federal tax effect	2.3 %	2.0 %
Increases (decreases) in tax from:		
Regulatory differences – average rate assumption method (ARAM) [(b)]	(4.2)	—
Tax Reform	—	(3.5)
Adjustments attributable to tax returns	(1.5)	(0.4)
Regulatory differences - other utility plant items	(1.3)	(0.8)
Amortization of excess nonplant deferred taxes	(1.2)	—
Tax credits recognized, net of federal income tax expense	(0.7)	(0.7)
Regulatory differences - Deferral of ARAM [(c)]	0.7	—
Other, net	0.3	(1.5)
Effective income tax rate	15.4 %	30.1 %

(a) Prior periods have been reclassified to conform to current year presentation.

(b) ARAM is a method to flow back excess deferred taxes to customers.

(c) ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2018	2017
Current federal tax expense (benefit)	$ 12.3	$ (20.9)
Current state tax expense (benefit)	2.3	(12.7)
Current change in unrecognized tax expense (benefit)	0.7	(2.2)
Deferred federal tax expense	20.0	90.0
Deferred state tax expense	3.6	14.4
Deferred change in unrecognized tax (benefit) expense	(0.1)	(0.1)
Deferred ITCs	0.1	(0.1)
Total income tax expense	$ 38.9	$ 68.4

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax expense (benefit) excluding items below	$ 45.8	$ (436.3)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(22.0)	540.7
Tax (expense) benefit allocated to other comprehensive income, net of adoption of FASB Accounting Standards Update (ASU) No. 2018-02, and other	(0.2)	—
Deferred tax expense	$ 23.6	$ 104.4

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Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 772.8	$ 740.3
Regulatory assets	(90.9)	(94.6)
Pension expense	32.3	33.8
Other	4.0	3.9
Total deferred tax liabilities	$ 718.2	$ 683.4
Deferred tax assets:		
Differences between book and tax bases of property	$ 84.9	$ 80.1
Regulatory liabilities	(23.2)	(26.8)
NOL carryforward	0.2	28.9
Deferred fuel costs	12.7	10.4
Other employee benefits	5.6	5.8
Tax credit carryforward	7.4	6.3
Other	13.8	7.7
Total deferred tax assets	$ 101.4	$ 112.4
Net deferred tax liability	$ 616.8	$ 571.0

In December 2017, SPS re-measured 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 re-measurement of our 2017 deferred tax assets and liabilities to the new corporate tax rate. SPS received guidance from some jurisdictions in 2018 and started the amortization of the deficient and excess 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 ADIT's, are amortized according to each jurisdiction. The Non-plant Unprotected have amortization periods of 5 years while, Plant Unprotected will use ARAM.

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The amount of deficient and excess accumulated deferred income tax assets and liabilities that are considered protected and unprotected as of December 31, 2018 and 2017 is reflected below:

(Amounts in Millions)	2018		2017	
FERC Account	**182.3**	**254**	**182.3**	**254**
Protected				
Plant	$ -	$ 468.9	$ -	$ 469.9
Nonplant	54.8	-	43.1	-
Unprotected				
Plant	-	69.8	-	70.7
Nonplant	1.0	(23.0)	1.6	(28.0)
Total				
Plant	$ -	$ 538.7	$ -	$ 540.6
Nonplant	$ 55.8	$ (23.0)	$ 44.7	$ (28.0)

Excess and deficient accumulated deferred income taxes (ADITs) in 2018 were amortized in the Statement of Income as follows:

(Amounts in Millions)	**2018**
Protected	
Plant	(6.6)
Nonplant	0.5
Unprotected	
Plant	(2.3)
Nonplant	(3.4)
Total	
Plant	(8.9)
Nonplant	(2.9)

6. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The 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 — Fair values of cash equivalents are based on cost plus accrued interest; money market funds are measured using quoted NAVs.

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 financial transmission rights (FTRs), purchased from 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 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 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, 2018, accumulated other comprehensive losses related to interest rate derivatives included $0.1 million 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.

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 commodity FTRs at Dec. 31, 2018 and 2017:

(Amounts in Millions) [(a)]	**Dec. 31, 2018**	**Dec. 31, 2017**
Megatwatt hours (MWh) of electricity	5.5	4.3

(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, 2018, two of the eight most significant counterparties for these activities, comprising $11.6 million or 28% of this credit exposure, had investment grade ratings from Standard & Poor's, Moody's or Fitch Ratings. Five of the eight most significant counterparties, comprising $8.7 million or 21% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising $0.6 million or less than 1% of this credit exposure, had credit quality less than investment grade, based on external analysis. Six of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate cash flow hedges on SPS' accumulated other comprehensive loss, included in the statements of common stockholder's equity and in the statements of comprehensive income:

(Millions of Dollars)	**2018**	**2017**
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (0.8)	$ (0.7)
After-tax net realized losses on derivative transactions reclassified into earnings	0.1	—
Adoption of ASU. 2018-02 [(a)]	—	(0.1)
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (0.7)	$ (0.8)

(a) In 2017, SPS implemented ASU No. 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were $0.1 million for the years ended Dec. 31, 2018 and 2017, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains of $7.0 million and $0.5 million recognized for the years ended Dec. 31, 2018 and 2017, respectively, 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 of $4.4 million and $0.8 million were recognized for the years ended Dec. 31, 2018 and 2017, 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 years ended Dec. 31, 2018 and 2017.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2018 and 2017:

	Dec. 31, 2018						Dec. 31, 2017					
	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	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	$ 14.7	$ —	$ —	$ 14.7	$ 14.7	$ (2.0)	$ 12.7
Total current derivative assets	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	14.7	$ —	$ —	$ 14.7	$ 14.7	$ (2.0)	12.7
PPAs (b)						3.1						3.2
Current derivative instruments						$ 17.8						$ 15.9
Noncurrent derivative assets												
PPAs (b)						15.8						19.0
Noncurrent derivative instruments						$ 15.8						$ 19.0
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	$ —	$ —	$ —	$ 2.0	$ 2.0	$ (2.0)	$ —
Total current derivative liabilities	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	—	$ —	$ —	$ 2.0	$ 2.0	$ (2.0)	—
PPAs (b)						3.6						3.6
Current derivative instruments						$ 3.6						$ 3.6
Noncurrent derivative liabilities												
PPAs (b)						16.4						19.9
Noncurrent derivative instruments						$ 16.4						$ 19.9

(a) SPS nets derivative instruments and related collateral in its balance sheet 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, 2018 and 2017. At both Dec. 31, 2018 and 2017, 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, 2018 and 2017:

	Year Ended Dec. 31	
(Millions of Dollars)	**2018**	**2017**
Balance at Jan. 1	$ 12.7	$ 2.0
Purchases	32.3	41.2
Settlements	(41.6)	(55.8)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets	11.3	25.3
Balance at Dec. 31	$ 14.7	$ 12.7

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2017 – 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2018		2017	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 2,146.5	$ 2,139.8	$ 1,848.2	$ 2,002.0

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, 2018 and 2017, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

7. Benefit Plans and Other Postretirement Benefits

Xcel Energy, which includes SPS, has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. 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 supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants 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 operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2018 and 2017 were $33 million and $37 million, respectively, of which $2 million was attributable to SPS in 2018 and 2017. In 2018 and 2017, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million and $5 million, respectively, of which immaterial amounts were attributable to SPS.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan. Rabbi trust funding of deferred compensation plan distributions attributable to SPS will be supplemented by SPS's operating cash flows.

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- Xcel Energy discontinued health care benefits for SPS bargaining employees hired after Jan. 1, 2012.
- Xcel Energy discontinued subsidizing health care benefits for nonbargaining employees of the former New Century Energies, Inc. (NCE), which includes SPS employees, who retired after June 30, 2003.

Xcel Energy, which includes SPS, bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 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 2018 were below the assumed level of 6.78%;
- Investment returns in 2017 were above the assumed level of 6.78%;
- In 2019, Xcel Energy's expected investment-return assumption is 6.78%.

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 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.

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Pension Plan Assets

The following presents, for each of the fair value hierarchy levels, SPS' pension plan assets measured at fair value:

	Dec. 31, 2018					Dec. 31, 2017				
(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	$ 21.6	$ —	$ —	$ —	$ 21.6	26.9	—	—	—	$ 26.9
Commingled funds:	128.6	—	—	132.5	261.1	145.7	—	—	142.7	288.4
Debt securities:	—	98.1	—	—	98.1	—	105.3	—	—	105.3
Equity securities:	14.4	—	—	—	14.4	15.2	—	—	—	15.2
Other	0.2	0.8	—	(4.0)	(3.0)	(3.3)	0.6	—	0.1	(2.6)
Total	$ 164.8	$ 98.9	$ —	$ 128.5	$ 392.2	$ 184.5	$ 105.9	$ —	$ 142.8	$ 433.2

The following presents, 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, 2018 (a)					Dec. 31, 2017 (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	$ 1.8	$ —	$ —	$ —	$ 1.8	$ 2.8	$ —	$ —	$ —	$ 2.8
Insurance contracts	—	4.3	—	—	4.3	—	4.7	—	—	4.7
Commingled funds:	12.8	—	—	3.8	16.6	14.1	—	—	—	14.1
Debt securities:	—	17.2	—	—	17.2	—	19.0	—	—	19.0
Equity securities:	—	—	—	—	—	3.3	—	—	—	3.3
Other	—	0.1	—	—	0.1	—	0.2	—	—	0.2
Total	$ 14.6	$ 21.6	$ —	$ 3.8	$ 40.0	$ 20.2	$ 23.9	$ —	$ —	$ 44.1

(a) See Note 7 for further information on fair value measurement inputs and methods.

No assets transferred in or out of Level 3 for the years ended Dec. 31, 2018 or 2017.

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Funded Status — 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 presented in the following table:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2018**	**2017**	**2018**	**2017**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 515.9	$ 483.6	$ 47.0	$ 41.9
Service cost	9.7	9.8	1.1	0.9
Interest cost	18.4	19.7	1.6	1.7
Plan amendments	—	(1.0)	—	—
Actuarial (gain) loss	(34.8)	31.2	(5.1)	4.7
Plan participants' contributions	—	—	0.6	0.6
Benefit payments [(a)]	(31.4)	(27.4)	(3.4)	(2.8)
Obligation at Dec. 31	$ 477.8	$ 515.9	$ 41.8	$ 47.0
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 433.2	$ 380.4	$ 44.1	$ 42.3
Actual return on plan assets	(17.6)	56.7	(1.3)	3.8
Employer contributions	8.0	23.5	—	0.2
Plan participants' contributions	—	—	0.6	0.6
Benefit payments	(31.4)	(27.4)	(3.4)	(2.8)
Fair value of plan assets at Dec. 31	$ 392.2	$ 433.2	$ 40.0	$ 44.1
Funded status of plans at Dec. 31	$ (85.6)	$ (82.7)	$ (1.8)	$ (2.9)
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent liabilities	(85.6)	(82.7)	(1.8)	(2.9)
Net amounts recognized	$ (85.6)	$ (82.7)	$ (1.8)	$ (2.9)
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	4.31%	3.63%	4.32%	3.62%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	RP-2014	RP-2014	RP-2014	RP-2014
Health care costs trend rate — initial: Pre-Medicare (Pre-65)	N/A	N/A	6.50%	7.00%
Health care costs trend rate — initial: Post-Medicare (Post-65)	N/A	N/A	5.30%	5.50%
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

(a) Includes approximately $6.9 million in 2018 and $0 million in 2017, of lump-sum benefit payments used in the determination of a settlement charge.

Accumulated benefit obligation for the pension plan was $445.8 million and $478.8 million as of Dec. 31, 2018 and 2017, respectively.

***Net Periodic Benefit Cost (Credit)* —** Net periodic benefit cost (credit) other than service cost component is included in other income in the statement of income.

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Components of net periodic benefit cost (credit) and the amounts recognized in other comprehensive income and regulatory assets and liabilities are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2018**	**2017**	**2018**	**2017**
Service cost	$ 9.7	$ 9.8	$ 1.1	$ 0.9
Interest cost	18.4	19.7	1.6	1.7
Expected return on plan assets	(28.3)	(27.9)	(2.5)	(2.4)
Amortization of prior service credit	(0.1)	—	(0.4)	(0.4)
Amortization of net loss	14.1	13.0	(0.4)	(0.6)
Settlement charge [(a)]	3.2	—	—	—
Net periodic pension cost (credit)	17.0	14.6	(0.6)	(0.8)
Costs not recognized due to effects of regulation	(2.2)	0.3	—	—
Net benefit cost (credit) recognized for financial reporting	$ 14.8	$ 14.9	$ (0.6)	$ (0.8)
Significant Assumptions Used to Measure Costs:				
Discount rate	3.63%	4.13%	3.62%	4.13%
Expected average long-term increase in compensation level	3.75	3.75	—	—
Expected average long-term rate of return on assets	6.78	6.78	5.80	5.80

(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 2018, as a result of lump-sum distributions during the 2018 plan year, SPS recorded a total pension settlement charge of $3.3 million the majority of which $0 million was not recognized due to the effects of regulation.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2018**	**2017**	**2018**	**2017**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 230.9	$ 237.0	$ (9.6)	$ (8.6)
Prior service credit	(1.2)	(1.3)	(1.8)	(2.2)
Total	$ 229.7	$ 235.7	$ (11.4)	$ (10.8)
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	$ 12.9	$ 13.9	$ —	$ —
Noncurrent regulatory assets	216.8	221.8	—	—
Current regulatory liabilities	—	—	(0.9)	(0.8)
Noncurrent regulatory liabilities	—	—	(10.5)	(10.0)
Total	$ 229.7	$ 235.7	$ (11.4)	$ (10.8)
Measurement date	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2017 - 2019 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $150 million in January 2019, of which $17 million was attributable to SPS;
- $150 million in 2018, of which $8 million was attributable to SPS;
- $162 million in 2017, of which $24 million was attributable to SPS; and,

For future years, Xcel Energy and SPS anticipate contributions will be made as necessary.

The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations 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:

- Expects to contribute approximately $11 million during 2019;
- $11 million during 2018;
- $20 million during 2017; and,
- Amounts attributable to SPS were immaterial.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2018	**2017**	**2018**	**2017**
Domestic and international equity securities	35%	34%	18 %	24 %
Long-duration fixed income securities	32	31	—	—
Short-to-intermediate fixed income securities	16	19	70	60
Alternative investments	15	14	8	9
Cash	2	2	4	7
Total	100%	100%	100 %	100 %

Plan Amendments — Xcel Energy, which includes SPS, amended the Xcel Energy Inc. Nonbargaining Pension Plan (South) in 2017 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.

In 2018, there were no plan amendments made which affected the benefit obligation.

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
2019	29.7	3.2	—	3.2
2020	30.0	3.1	—	3.1
2021	29.3	3.2	—	3.2
2022	30.8	3.2	—	3.2
2023	30.8	3.2	—	3.2
2024-2028	156.2	14.4	0.2	14.2

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 2018 and 2017.

8. Commitments and Contingencies

Legal

SPS is involved in various litigation matters that are being defended and handled 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 complex judgments about future events. Management maintains accruals for losses that are 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 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, arising from such current proceedings would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

SPP OATT Upgrade Costs — Under the SPP Open Access Transmission Tariff (OATT), costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately $13 million for these charges.

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 these charges was remanded to the FERC. SPS' recovery of these charges (from 2008 through 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC has granted a rehearing of further consideration in May 2018. The timing of the FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

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 could result in an increase in the annual transmission revenue requirement (ATRR) of $9.5 million per year, with $6 million allocated to SPS' retail customers.

The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone. In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On October 31, 2018, the FERC issued an order accepting the proposed charges as of November 1, 2018. In December 2018, the FERC hosted a settlement hearing over the matter. A hearing will be ordered if a settlement is not reached.

SPS Filing to Modify Wholesale Transmission Rates - In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to the depreciation rates for transmission plant. The new formula rate would provide flow-back of "excess" ADIT resulting from the TCJA and recover certain wholesale regulatory commission expenses.

The proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total being recovered in SPP regional transmission rates. SPS proposed that the formula rate changes be effective February 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of February 1, 2019, subject to refund and settlement procedures. The first settlement conference is expected in the first quarter of 2019.

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 its 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.

MGP, Landfill or Disposal Sites — SPS is currently investigating or remediating one MGP, landfill or other disposal site across its service territories, and these activities will continue through at least 2019. SPS accrued $0.1 million as of Dec. 31, 2018 and 2017, respectively, for this site. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting some portion of costs incurred.

Environmental Requirements — Water and Waste

Federal Clean Water Act (CWA) Waters of the United States (WOTUS) Rule — In 2015, the United States Environmental Protection Agency (EPA) and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". The Rule has been subject to significant litigation and is currently stayed in a portion of the country. SPS cannot estimate potential impacts until the legal and administrative processes are finalized, but expects costs will be recoverable through regulatory mechanisms.

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Federal CWA effluent limitations 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 (CCRs). In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, SPS estimates that ELG compliance will be immaterial.

The EPA, however, is conducting a rulemaking process to potentially revise the effluent limitations and pretreatment standards, which may impact compliance costs. SPS estimates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires sulfur dioxide (SO_2), nitrogen oxide (NO_X) and particulate matter (PM) 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 as described below.

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 United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The 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. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. 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. It is not known when the EPA will make a final decision on this proposal.

Reasonable Progress Rule: In January 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, with compliance 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 are needed at Tolk under the "reasonable progress" requirements. The EPA has not announced a schedule for acting 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 an exception. The EPA issued final designations which found the area near the Harrington plant as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020.

If the area near the Harrington plant is designated nonattainment in 2020, the Texas Commission on Environmental Quality (TCEQ) will need to develop an implementation plan, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. SPS cannot evaluate the impacts until the final designation is made and any required state plans are developed.

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SPS believes that should SO_2 control systems be required for a plant, 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 position or cash flows.

AROs — AROs have been recorded for SPS' assets.

SPS' AROs were as follows:

	Dec. 31, 2018			
(Millions of Dollars)	Balance Jan. 1, 2018	Accretion	Cash Flow Revisions (a)	Balance Dec. 31, 2018 (b)
Electric				
Steam production	$ 21.4	$ 1.3	$ 0.5	$ 23.2
Distribution	7.0	0.3	1.8	9.1
Common	0.1	—	—	0.1
Total liability	$ 28.5	$ 1.6	$ 2.3	$ 32.4

(a) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in electric distribution AROs were primarily related to increased labor costs.

There were no ARO amounts incurred or settled in 2018.

	Dec. 31, 2017			
(Millions of Dollars)	Balance Jan. 1, 2017	Accretion	Cash Flow Revisions (a)	Balance Dec. 31, 2017 (b)
Electric plant				
Steam production	$ 21.8	$ 1.3	$ (1.7)	$ 21.4
Distribution	6.8	0.2	—	7.0
Common	0.1	—	—	0.1
Total liability	$ 28.7	$ 1.5	$ (1.7)	$ 28.5

(a) In 2017, an asbestos ARO was revised for changes in timing of estimated cash flows.

(b) There were no ARO amounts incurred or settled in 2018.

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, 2018. Therefore, an ARO has not been recorded for these facilities.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Leases — SPS leases a variety of equipment and facilities. These leases, primarily for office space, generating facilities, vehicles, aircraft and power-operated equipment, are accounted for as operating leases.

Total expenses (including capacity payments) under operating lease obligations for SPS and the corresponding capacity payments for PPAs accounted for as operating leases for the year ended Dec. 31:

(Millions of Dollars)	2018	2017
Total expense	$ 59.0	$ 57.8
Capacity payments	51.1	51.4

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases.

Future commitments under operating leases are:

(Millions of Dollars)	Operating Leases	PPA (a) (b) Operating Leases	Total Operating Leases
2019	$ 5.2	$ 46.7	$ 51.9
2020	5.2	46.2	51.4
2021	5.1	46.2	51.3
2022	5.1	46.2	51.3
2023	5.1	46.2	51.3
Thereafter	56.3	450.8	507.1

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2033.

Non-Lease PPAs — SPS has entered into PPAs with other utilities and energy suppliers with expiration dates through 2033 for purchased power to meet system load and energy requirements and meet operating reserve obligations.
In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Capacity payments are contingent on the independent power producing entity (IPP) meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts, were payments for capacity of $57.6 million and $58.4 million in 2018 and 2017, respectively.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

At Dec. 31, 2018, 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
2019	$	20.3
2020		12.0
2021		12.2
2022		12.4
2023		12.6
Thereafter		5.7
Total	$	75.2

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 2019 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, 2018:

(Millions of Dollars)		Coal		Natural gas supply		Natural gas storage and transportation
2019	$	127.3	$	20.3	$	30.3
2020		83.9		—		30.3
2021		41.0		—		25.2
2022		41.2		—		19.3
2023		—		—		14.1
Thereafter		—		—		33.6
Total	**$**	293.4	**$**	20.3	**$**	152.8

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

9. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the year ended Dec. 31:

	2018				
(Millions of Dollars)	**Gains and Losses on Cash Flow Hedges**		**Defined Benefit Pension and Postretirement Items**		**Total**
Accumulated other comprehensive loss at Jan. 1	$ (0.8)		$ (0.7)		$ (1.5)
Losses reclassified from net accumulated other comprehensive loss:					
Interest rate derivatives (net of taxes of $0 and $0, respectively)	0.1	(a)	—		0.1
Amortization of net actuarial loss (net of taxes of $0 and $0, respectively)	—		—	(b)	—
Net current period other comprehensive income	0.1		—		0.1
Accumulated other comprehensive loss at Dec. 31	**$** (0.7)		**$** (0.7)		$ (1.4)

	2017				
(Millions of Dollars)	**Gains and Losses on Cash Flow Hedges**		**Defined Benefit Pension and Postretirement Items**		**Total**
Accumulated other comprehensive loss at Jan. 1	$ (0.7)		$ (0.6)		$ (1.3)
Losses reclassified from net accumulated other comprehensive loss:					
Interest rate derivatives (net of taxes of $0.1 and $0, respectively)	—	(a)	—		—
Amortization of net actuarial loss (net of taxes of $0 and $0, respectively)	—		0.1	(b)	0.1
Net current period other comprehensive income (loss)	—		0.1		0.1
Adoption of ASU No. 2018-02 (c)	(0.1)		(0.2)		(0.3)
Accumulated other comprehensive loss at Dec. 31	**$** (0.8)		**$** (0.7)		$ (1.5)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for further information.

In 2017, SPS implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within accumulated other comprehensive loss to retained earnings.

10. 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 the service 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, PSCo and SPS have established a utility money pool arrangement with the utility subsidiaries.

See Note 3 for further information.

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Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Significant affiliate transactions among the companies and related parties for the years ended Dec. 31:

(Millions of Dollars)	2018	2017
Operating expenses:		
Purchased power	$ —	$ 1.4
Other operating expenses — paid to Xcel Energy Services Inc.	195.1	196.6
Interest expense	**0.6**	—

Accounts receivable and payable with affiliates at Dec. 31 were:

	2018		**2017**	
(Millions of Dollars)	**Accounts Receivable**	**Accounts Payable**	**Accounts Receivable**	**Accounts Payable**
NSP-Minnesota	$ 4.7	$ —	$ 1.0	$ —
PSCo	—	0.7	—	0.3
Other subsidiaries of Xcel Energy Inc.	5.8	19.2	0.3	22.3
	$ 10.5	$ 19.9	$ 1.3	$ 22.6

11. Supplementary Cash Flow Data

	Twelve Months Ended Dec. 31	
(Millions of Dollars)	2018	2017
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (71.2)	$ (76.0)
Cash (paid) received for income taxes, net	(10.6)	41.5
Supplemental disclosure of non-cash investing transactions:		
Accrued Utility Plant additions	$ 71.5	$ 85.1
Inventory transfer additions in PPE	$ 22.5	$ 13.7
Allowance for equity funds used during construction	$ 19.1	$ 9.3

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)
1	Balance of Account 219 at Beginning of Preceding Year				(612,623)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(78,640)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(78,640)
5	Balance of Account 219 at End of Preceding Quarter/Year				(691,263)
6	Balance of Account 219 at Beginning of Current Year				(691,263)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				74,606
8	Current Quarter/Year to Date Changes in Fair Value				(47,797)
9	Total (lines 7 and 8)				26,809
10	Balance of Account 219 at End of Current Quarter/Year				(664,454)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	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 117, Line 78) (i)	Total Comprehensive Income (j)
1	(677,829)		(1,290,452)	[redacted]	
2	(97,376)		(176,016)		
3					
4	(97,376)		(176,016)	159,213,104	159,037,088
5	(775,205)		(1,466,468)	[redacted]	
6	(775,205)		(1,466,468)		
7	49,244		123,850		
8			(47,797)		
9	49,244		76,053	213,320,225	213,396,278
10	(725,961)		(1,390,415)	[redacted]	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Includes a (259,990) reclassification from Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	6,528,739,176	6,528,739,176
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	691,304,704	691,304,704
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	7,220,043,880	7,220,043,880
9	Leased to Others		
10	Held for Future Use	4,167,109	4,167,109
11	Construction Work in Progress	849,058,368	849,058,368
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	8,073,269,357	8,073,269,357
14	Accum Prov for Depr, Amort, & Depl	2,315,941,276	2,315,941,276
15	Net Utility Plant (13 less 14)	5,757,328,081	5,757,328,081
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,183,663,453	2,183,663,453
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	132,277,823	132,277,823
22	Total In Service (18 thru 21)	2,315,941,276	2,315,941,276
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	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,315,941,276	2,315,941,276

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
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					29
					30
					31
					32
					33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 21 Column: c

The amortization of other utility plant within account 111 includes the following:

Intangible Plant	$104,658,587
Transmission	21,160,536
Steam Production	4,116,669
Distribution	1,452,317
General	889,031
Other Production	683
Total	$132,277,823

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	213,477,776	15,998,783
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	213,477,776	15,998,783
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	17,070,833	7,212
9	(311) Structures and Improvements	235,853,620	5,124,073
10	(312) Boiler Plant Equipment	987,665,953	21,915,564
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	502,823,517	8,659,760
13	(315) Accessory Electric Equipment	79,642,962	4,549,021
14	(316) Misc. Power Plant Equipment	31,471,035	592,871
15	(317) Asset Retirement Costs for Steam Production	-775,689	521,613
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,853,752,231	41,370,114
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	116,726	91,571
38	(341) Structures and Improvements	14,286,887	115,009
39	(342) Fuel Holders, Products, and Accessories	6,071,842	
40	(343) Prime Movers	54,833,944	10,724
41	(344) Generators	176,638,178	909,487
42	(345) Accessory Electric Equipment	31,673,217	42,592
43	(346) Misc. Power Plant Equipment	4,669,321	76,209
44	(347) Asset Retirement Costs for Other Production	136,263	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	288,426,378	1,245,592
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,142,178,609	42,615,706

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	143,581,246	17,012,584
49	(352) Structures and Improvements	80,297,916	21,887,318
50	(353) Station Equipment	1,000,230,593	127,565,536
51	(354) Towers and Fixtures	8,243,671	-65,990
52	(355) Poles and Fixtures	1,051,696,154	112,571,151
53	(356) Overhead Conductors and Devices	392,678,011	55,035,925
54	(357) Underground Conduit	255,073	17,786
55	(358) Underground Conductors and Devices	489,716	
56	(359) Roads and Trails	517,736	
57	(359.1) Asset Retirement Costs for Transmission Plant	25,029	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,678,015,145	334,024,310
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	11,343,706	3,558,656
61	(361) Structures and Improvements	18,745,714	8,011,256
62	(362) Station Equipment	266,468,615	22,895,696
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	264,771,145	33,687,677
65	(365) Overhead Conductors and Devices	266,346,874	7,322,374
66	(366) Underground Conduit	24,880,849	456,704
67	(367) Underground Conductors and Devices	42,616,679	2,604,908
68	(368) Line Transformers	205,734,651	14,116,327
69	(369) Services	85,081,560	4,001,023
70	(370) Meters	66,842,880	2,438,494
71	(371) Installations on Customer Premises	13,066,807	15,263
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	25,738,865	2,184,038
74	(374) Asset Retirement Costs for Distribution Plant	5,621,098	1,846,270
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,297,259,443	103,138,686
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	1,185,297	
87	(390) Structures and Improvements	71,689,758	1,271,497
88	(391) Office Furniture and Equipment	78,135,426	9,261,727
89	(392) Transportation Equipment	103,819,391	8,754,371
90	(393) Stores Equipment	430,682	
91	(394) Tools, Shop and Garage Equipment	36,597,581	7,543,542
92	(395) Laboratory Equipment	11,003,373	266,420
93	(396) Power Operated Equipment	14,782,676	33,567
94	(397) Communication Equipment	105,358,139	13,299,847
95	(398) Miscellaneous Equipment	2,782,383	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	425,784,706	40,430,971
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	64,395	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	425,849,101	40,430,971
100	TOTAL (Accounts 101 and 106)	6,756,780,074	536,208,456
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)	6,756,780,074	536,208,456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
13,598,928			215,877,631		4
13,598,928			215,877,631		5
					6
					7
			17,078,045		8
272,454			240,705,239		9
7,010,201			1,002,571,316		10
					11
2,958,190			508,525,087		12
317,371			83,874,612		13
			32,063,906		14
			-254,076		15
10,558,216			1,884,564,129		16
					17
					18
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					35
					36
		-1,004	207,293		37
			14,401,896		38
			6,071,842		39
7,053			54,837,615		40
105,668			177,441,997		41
			31,715,809		42
			4,745,530		43
			136,263		44
112,721		-1,004	289,558,245		45
10,670,937		-1,004	2,174,122,374		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			160,593,830		48
291,910		-260,684	101,632,640		49
18,819,159		-805,900	1,108,171,070		50
			8,177,681		51
4,526,523		1,012,076	1,160,752,858		52
1,765,914		54,509	446,002,531		53
			272,859		54
			489,716		55
			517,736		56
			25,029		57
25,403,506		1	2,986,635,950		58
					59
2,620			14,899,742		60
62,277			26,694,693		61
2,565,145			286,799,166		62
					63
1,562,739			296,896,083		64
2,358,877			271,310,371		65
12,206			25,325,347		66
142,376			45,079,211		67
1,514,914			218,336,064		68
33,033			89,049,550		69
2,136,860			67,144,514		70
9,969,930		-3,110,631	1,509		71
					72
481,185		3,110,631	30,552,349		73
			7,467,368		74
20,842,162			1,379,555,967		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
82,088			1,103,209		86
			72,961,255		87
1,913,081		11,524	85,495,596		88
			112,573,762		89
			430,682		90
151,780			43,989,343		91
89,060			11,180,733		92
			14,816,243		93
191,278		-11,524	118,455,184		94
826			2,781,557		95
2,428,113			463,787,564		96
					97
			64,395		98
2,428,113			463,851,959		99
72,943,646		-1,003	7,220,043,881		100
					101
					102
					103
72,943,646		-1,003	7,220,043,881		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 58 Column: b

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 352 - Structures & Improvements	931,777	-	-	-	(207,806)	723,970
Account 353 - Station Equipment	29,809,004	7,884	(333,236)	-	-	29,483,652
Account 355 - Poles & Fixtures	247,874	12,600	-	-	-	260,474
Account 356 - Overhead Conductors & Devices	24,718	-	-	-	-	24,718

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
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45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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	2015	2019 +	4,167,109
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
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45				
46				
47	Total			4,167,109

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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	SPS Wind -Hale County	561,895,854
2	TUCO-Yoakum 345kV Line_UID 504	32,623,802
3	TX/NM Border-Hobbs 345kV Line_	29,111,346
4	Yoakum-TX/NM Border 345kV Line	28,553,205
5	Hale-Sub Serving Generation	13,696,638
6	Hale-Xmsn Serving Generation	11,115,570
7	Eddy County Dbl Bus Dbl Brkr 230kV	10,472,433
8	Canyon Service Center - New	6,886,278
9	ADMS SW SPS	6,445,571
10	SPS Wind - Sagamore	5,882,870
11	115Line Mustang-Shell Trans Po	5,613,720
12	Plant X Add BFR on All 115 kV	5,472,549
13	Shell Substation Sub Portion	5,457,148
14	Deaf Smith 230kV Breaker ADD S	4,405,143
15	Purch SPS Quantar Repeater HW	4,019,106
16	OPIE Potash-Livingston Ridge	3,908,041
17	Inst 230kV Sw Station XcelPortion	3,734,005
18	IMC1-Intrepid West 115kv Recd	3,423,907
19	ink basin substation	2,754,364
20	SPS ELR 115kV TX 2016	2,501,064
21	Inst 115kV Quincy Sw Station Xcel P	2,334,011
22	Hobbs 345kV Sub Reactor/Yoakum	2,239,959
23	Seminole Xfmr 2	2,059,187
24	Install Hunsley Substation - Land	2,029,703
25	Yoakum Sub Xmfr 345kV/230KV_UI	2,023,992
26	Kiowa-Eddy Co 345kV Line Pre C	1,994,271
27	Purch T&D MPLS - Unplanned (2017) S	1,858,335
28	Purc 28mva mobile XFER Delta Star	1,824,581
29	Plant X Rpl Brkr Switch WT Sub	1,809,153
30	CIP Substation Ph2 SW SPS -10659	1,741,723
31	Install Hillside #2 115/13.2kV	1,740,115
32	Bailey County-New Amherst 115k	1,663,743
33	TEXAS MAJOR STORM RECOVERY	1,621,301
34	HAR3C - Rpl CT Hot Water Deck	1,577,337
35	Purch LMR Radio HW NM	1,570,330
36	ESB Environment SW SPS-10646	1,549,280
37	SPS Major Line Refurb 69kV TX 2016	1,484,824
38	Mustang Sub Sub Portion Sub	1,334,686
39	SPS Transmission UAV	1,291,590
40	TX - OH Rebuild Blanket	1,191,672
41	Plant X Distribution Relay Equ	1,152,366
42	Yoakum 230/115 Xfmr 1 Upgrade	1,095,053
43	TOTAL	849,058,368

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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	TX - Pole Blanket	1,005,625
2		
3	Minor Projectsq	62,892,917
4		
5		
6		
7		
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42		
43	TOTAL	849,058,368

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), 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.

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	2,099,803,658	2,099,803,658		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	168,450,121	168,450,121		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,943	1,943		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	7,738,251	7,738,251		
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)	176,190,315	176,190,315		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	59,344,719	59,344,719		
13	Cost of Removal	29,624,907	29,624,907		
14	Salvage (Credit)	1,682,942	1,682,942		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	87,286,684	87,286,684		
16	Other Debit or Cr. Items (Describe, details in footnote):	-5,043,836	-5,043,836		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,183,663,453	2,183,663,453		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,120,387,291	1,120,387,291		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	86,199,848	86,199,848		
25	Transmission	421,745,016	421,745,016		
26	Distribution	361,116,419	361,116,419		
27	Regional Transmission and Market Operation				
28	General	194,214,879	194,214,879		
29	TOTAL (Enter Total of lines 20 thru 28)	2,183,663,453	2,183,663,453		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 16 Column: c

Net change in RWIP	$ (5,050,845)
(Gain)/Loss	6,905
Other	104
Total	$ (5,043,836)

Schedule Page: 219 Line No.: 25 Column: c

Transmission Serving Production	$ 15,963,900

Schedule Page: 219 Line No.: 29 Column: b

	"Non-Legal" ARO Balances
Steam Production	$ 102,547,822
Other Production	2,518,807
Transmission	23,626,311
Distribution	57,231,336
General	1,799,910
Total	$ 187,724,186

Schedule Page: 219 Line No.: 29 Column: c

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)
1	Balance Beginning of Year	$ 2,252,765,335	$ 2,252,765,335
2	Depreciation Provisions for Year, Charged to		
3	(403) Depreciation Expense	154,714,558	154,714,558
4	(403.1) Depreciation Expense for Asset Retirement Costs	-	-
5	(413) Exp of Elec Plt. Leas. To Others	-	-
6	Transportation Expenses-Clearing	7,485,736	7,485,736
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)	162,200,294	162,200,294
11	Net Charges for Plant Retired		
12	Book Cost of Plant Retired	59,344,719	59,344,719
13	Cost of Removal	29,624,907	29,624,907
14	Salvage (Credit)	1,682,942	1,682,942
15	Total Net Chrgs for Plant Ret. (Enter Total of lines 12 thru 14)	87,286,684	87,286,684
16	Other Debit or Cr. Items (Describe,	(4,848,388)	(4,848,388)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

	details in footnote):		
17			
18	Book Cost or Asset Retirement Costs Retired	-	-
19	Balance End of Year (Enter Totals of lines 1,10,15,16 and 18)	$ 2,322,830,557	$ 2,322,830,557
	Section B. Balances at End of Year According to Functional Classification		
20	Steam Production	$ 1,307,041,310	$ 1,307,041,310
21	Nuclear Production	-	-
22	Hydraulic Production-Conventional	-	-
23	Hydraulic Production-Pumped Storage	-	-
24	Other Production	99,339,518	99,339,518
25	Transmission	348,333,321	348,333,321
26	Distribution	359,842,881	359,842,881
27	Regional Transmission and Market Operation		-
28	General	208,273,527	208,273,527
29	Total (Enter Total of lines 20 thru 28)	$ 2,322,830,557	$ 2,322,830,557

Net change in RWIP	$ (5,050,845)
Gain/Loss	202,356
Other	101
Total	$ (4,848,388)

*Total agrees to line 16 in the schdedule above.

Transmission Serving Production Reserve	$ 16,618,097

*Footnote to line 25 in the schdedule above.

	"Non-Legal" ARO Balances
Steam Production	$ 165,843,903
Other Production	2,898,621
Transmission	(79,127,386)
Distribution	57,231,336
General	3,013,337
Total	$ 149,859,811

*Footnote to lines 20-28 in the schdedule above.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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 form investments, including such revenues form 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 difference 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

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)	Line No.
				1
				2
				3
				4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)	14,215,177	8,202,732	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)	9,550,325	10,473,965	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	10,966,393	9,982,557	Electric
8	Transmission Plant (Estimated)	131,968	121,150	Electric
9	Distribution Plant (Estimated)	824,865	360,782	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-190,450	-127,883	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	21,283,101	20,810,571	
13	Merchandise (Account 155)	244,327	188,238	
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 (Per Balance Sheet)	35,742,605	29,201,541	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 11 Column: b

Balance is compromised of miscellaneous inventory-related items (including purchase price variances, obsolence and suspense items).

Schedule Page: 227 Line No.: 11 Column: c

Balance is compromised of miscellaneous inventory- related items (including purchase price variances, obsolesence and suspense items).

Balance includes chemical inventory (ARKAY). Beginning balance of chemical inventory as of January 1 was $58,998 and ending balance as of December 31, 2018 is $ 85,067.

Balance includes chemical inventory (Mercury Sorbent). Beginning balance of chemical inventory as of January 1 was $79,754 and ending balance as of December 31, 2018 is $63,786.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	203,727.00		53,364.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	22,395.00	5,133		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	181,332.00	-5,133	53,364.00	
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	771.00		771.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	771.00			
40	Balance-End of Year			771.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	771.00	7		
45	Gains		7		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
53,364.00		53,364.00		1,440,828.00		1,804,647.00		1
								2
								3
				53,364.00		53,364.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						22,395.00	5,133	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
53,364.00		53,364.00		1,494,192.00		1,835,616.00	-5,133	29
								30
								31
								32
								33
								34
								35
771.00		771.00		20,817.00		23,901.00		36
				1,542.00		1,542.00		37
								38
				771.00		1,542.00		39
771.00		771.00		21,588.00		23,901.00		40
								41
								42
								43
				771.00	2	1,542.00	9	44
					2		9	45
								46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 228 Line No.: 1 Column: b

2017 and prior SO2 bank (ARP & CSAPR)	150,363
2018 ARP	53,364
	203,727

Schedule Page: 228 Line No.: 1 Column: d

2019 Annual ARP allowances 53,364

Schedule Page: 228 Line No.: 1 Column: f

2020 Annual ARP allowances 53,364

Schedule Page: 228 Line No.: 1 Column: h

2021 Annual ARP allowances 53,364

Schedule Page: 228 Line No.: 1 Column: j

Sum of all ARP Allowances years 2022 and forward to 2047 1,440,828

Schedule Page: 228 Line No.: 4 Column: j

This is the allocations added this year for 2048 53,364

Schedule Page: 228 Line No.: 18 Column: b

ARP charges (includes NM units)	22,395
CSAPR charges (Texas only in CSAPR program)	-
	22,395

Schedule Page: 228 Line No.: 18 Column: c

Amortization of previously deferred SO2 cost (Case No. 17-00255-UT) in FERC 509	$	5,133
	$	5,133

Schedule Page: 228 Line No.: 29 Column: c

Value of SO2 allowance inventory per books $ -

Schedule Page: 228 Line No.: 45 Column: m

Gain-Disposition of SO2 Allowances	$	61.94
SO2 Texas Retail Sharing		(34.57)
SO2 New Mexico Retail Sharing		(18.45)
		8.92

Value of SO2 allowance inventory $0	$	0.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	7,019.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	64.00		4,044.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:	657.00	124,830		
9					
10					
11					
12					
13					
14					
15	Total	657.00	124,830		
16					
17	Relinquished During Year:				
18	Charges to Account 509	4,581.00	117,357		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	3,159.00	7,473	4,044.00	
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2020 No. (f)	2020 Amt. (g)	2021 No. (h)	2021 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
						7,019.00		1
								2
								3
4,044.00						8,152.00		4
								5
								6
								7
						657.00	124,830	8
								9
								10
								11
								12
								13
								14
						657.00	124,830	15
								16
								17
						4,581.00	117,357	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
4,044.00						11,247.00	7,473	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 229 Line No.: 1 Column: b

2017 and prior bank (CSAPR & CSAPR Ozone)	2,975
Original Allocation for 2018 (CSAPR Ozone NOx)	4,044
Total	7,019

Schedule Page: 229 Line No.: 4 Column: b

Excess NUSA 2017 Seasonal NOx allowances	64
	64

Schedule Page: 229 Line No.: 4 Column: d

CSAPR Ozone Nox Group 2 2019 vintage	4,044

Schedule Page: 229 Line No.: 4 Column: f

CSAPR Ozone Nox Group 2 2020 vintage	4,044

Schedule Page: 229 Line No.: 8 Column: b

2017 and 2018 Vintage Ozone NOx Allowances Purchased	657

Schedule Page: 229 Line No.: 8 Column: c

2017 and 2018 Vintage Ozone NOx Allowances Purchased	$124,830.00

Schedule Page: 229 Line No.: 18 Column: b

Seasonal Nox emissions for 2018	4,581
	4,581

Schedule Page: 229 Line No.: 18 Column: c

2017 and 2018 Vintage Ozone NOx Allowances Purchased	$ 124,830
New Mexico deferral of current year NOx allowance purchase	(30,994)
Amortization of previously deferred NOx cost (Case No. 17-00255-UT) in FERC 509	23,521
	$ 117,357

Schedule Page: 229 Line No.: 29 Column: b

CSAPR Annual Allowances Banked	2,724

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

2018 Ozone NOx Allowances Banked	435
	3,159

Schedule Page: 229 Line No.: 29 Column: c

Value of NOx allowance inventory per books	$ -

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Recognised 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	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Recognised 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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	DPA-2018-Jan-854 Lea Co KinderMo	24,812	561.6	24,812	561.6
3	DPA-2018-Jan-854 Lea Co KinderMo			188	232
4	Trans IC DP-RBEC-Kemp			12,500	232
5	SISA for SPEC Milwaukee-Yuma	5,451	561.6	5,451	561.6
6	SISA for SPEC Milwaukee-Yuma			9,549	232
7	TCEC/SCMCM Cole Mode Study AQ-863	2,232	561.6	2,232	561.6
8	TCEC/SCMCM Cole Mode Study AQ-863			10,268	232
9	Oxy Permian Sub LI_SPP DPA-869	869	561.6	869	561.6
10	SPEC - Carlisle Tap NDP	3,281	561.6	3,281	561.6
11	SPEC - Carlisle Tap NDP			11,719	232
12	LPL DPA-2018-May-897	3,039	561.6	3,039	561.6
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 the 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	236,036,764	11,222,428	Various	17,232,206	230,026,986
2						
3	Pension and Employee Benefit Cap	(246,554)	2,237,057			1,990,503
4	- Texas PUC Docket #47527					
5						
6	AFUDC in Plant	23,887,530	3,995,027			27,882,557
7	- Amortized over plant life					
8						
9	Non-Nuclear Asset Retirement Obligations	24,201,472	1,532,213			25,733,685
10						
11	Prior Flow Thru and Excess ADIT	153,707		254	45,820	107,887
12						
13	DSM Texas Historical Docket #35763	1,673,346		908	1,673,346	
14	- Recovered in rates over 10 years					
15						
16	Texas Restructuring Meter	157,043		407.3	34,898	122,145
17	- A portion recovered in rates over 20 years					
18	Texas PUC Docket #25088					
19						
20	Texas Power Demand Factor	956,075		456	669,657	286,418
21	Docket #48498, Amortize Apr 2018 - Mar 2019					
22						
23	Texas Rate Revenue Refund	58,075		456	58,075	
24	Docket #43695					
25						
26	Transmission Formula - Attachment O True-up	15,074,186	5,832,115	Various	17,019,796	3,886,505
27						
28	Production Formula Rate True-up	1,240,925	152,663	447	1,393,588	
29						
30	New Mexico NOx and SO2 Expense	32,568	30,994	509	28,654	34,908
31						
32	DSM New Mexico Concurrent	151,774	11,669,642	Various	11,737,571	83,845
33	Docket #18-00139-UT					
34						
35	New Mexico RPS Rider	2,901,016	1,391,756	Various	4,292,772	
36	- Various amortizations					
37	Case #18-00201-UT					
38						
39	Power Purchased Contract Valuation Adjustments	1,400,630		244	405,773	994,857
40	- Amortized over life of the contracts					
41						
42	DSM Texas Energy Efficiency	77,709		254	77,709	
43	Texas PUC Docket #48324					
44	TOTAL	352,722,115	67,283,036		59,884,020	360,121,131

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	Nonplant Excess ADIT	44,685,283	14,771,888	283	3,614,851	55,842,320
3						
4	2016 TX Electric Rate Case Surcharge	280,566		Various	280,566	
5	Docket #47035					
6						
7	2017 TCRF Revenue Accrual		5,346,815			5,346,815
8	Docket #47527					
9						
10	Texas Z2 Transmission		6,547,145	407.3	1,231,989	5,315,156
11	Docket #47527					
12	5 Year Amortization					
13						
14	New Mexico Z2 Transmission		2,553,293	407.3	86,749	2,466,544
15	Case #17-00255-UT					
16	5 Year Amortization					
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						
43						
44	TOTAL	352,722,115	67,283,036		59,884,020	360,121,131

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 1 Column: e

Account charged:

184	13,971,206
926	3,261,000
	17,232,206

Schedule Page: 232 Line No.: 1 Column: f

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 follow based upon expected recovery in Rates:

Regulatory asset - Pension	$ 229,640,109
Regulatory asset - Non-qualified pension	386,877
	230,026,986

Schedule Page: 232 Line No.: 3 Column: b

The SPS pension tracker mechanism requires an entry to be made when pension expense differs from the baseline amount in base rates. In 2017, additional pension expense has been recorded, reducing the tracker balance to a credit position.
This item is recorded as a Regulatory Asset with a negative balance and right of offset to the larger Regulatory Asset (Line 1).

Schedule Page: 232 Line No.: 26 Column: e

Account charged:

421	439,043
456.1	11,779,053
565	4,801,700
	17,019,796

Schedule Page: 232 Line No.: 30 Column: e

The amount of $28,654 represents amortization of previously deferred NOx allowance costs under the New Mexico jurisdiction. Amortization authorized in Case No. 17-00255-UT. Amounts related to 2017 and 2018 NOx expense deferrals will be included in 2019 rate case to be filed in 2019.

2017 NOx	3,914
2018 NOx	30,994
	34,908

Schedule Page: 232 Line No.: 32 Column: e

Accounts charged:

431	20,818
908	11,716,752
	11,737,571

Schedule Page: 232 Line No.: 35 Column: e

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Accounts charged:

254	1,299,920
407.3	2,678,076
421	31,130
557	283,646
	4,292,772

Schedule Page: 232.1 Line No.: 2 Column: f

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Reserves (Net of Gross-Up)	Total
Electric	$ 45,326,586	$ 12,866,787	$(2,351,053)	$ 55,842,320
Total	$ 45,326,586	$ 12,866,787	$(2,351,053)	$ 55,842,320

*Total nonplant excess ADIT is $45,326,586. This amount would be included as an increase to rate base for purposes of calculating SPS formula rates, as applicable.

The Nonplant Excess Accumulated Deferred Income Taxes above include the following ungrossed amounts:

Bad Debts	270,153
CIP/DSM	134,978
Deferred Compensation Plan Reserve	32,326
Employee Incentive	395,566
Environmental Remediation	9,265
Federal Net Operating Loss Benefit	43,185,468
Fuel Tax Credit - Income Addback	795
Inventory Reserve	43,211
Non-Qualified Pension Plan	24,865
Performance Recognition Awards	4,954
Performance Share Plan	10,472
Post Employment Benefits - FAS 106	1,797,510
Post Employment Benefits - FAS 112	100,279
State Tax Deduction	27,601
Texas Margin Tax	(23,834)
Vacation Accrual	219,753
Total Electric	$ 46,233,362

Schedule Page: 232.1 Line No.: 4 Column: e

Accounts charged:

254	205,079
440.0	4,470
442	59,727
445	11,291
	280,566

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Sharing Unrealized MTM Prop	1,912,254	420,192			2,332,446
2	Margins					
3						
4	Long-term Income Tax and		462,597			462,597
5	Interest Receivable					
6						
7	Debt Issuance Expense		563,620	Various	497,499	66,121
8	Amortization over life of					
9	issued bonds					
10						
11	2015 Texas Elec Rate Case Cost	221,470	55,152	928	276,622	
12	Docket No. 43695					
13						
14	2016 Texas Elec Rate Case Cost	2,846,201	-417,081	928	1,026,746	1,402,374
15	Docket No. 45524					
16						
17	2016 Texas Fuel Reconciliation	625,713	-14	928		625,699
18	Docket No. 40625					
19						
20	2015 NM Retail Rate & Supreme	545,857		928	545,857	
21	Court Case					
22	Case Nos. 15-00139-UT &					
23	15-00296-UT					
24	2 Year amortization ending					
25	August 2018					
26						
27	2016 NM Retail Rate Case	1,076,136	-1,465	928	1,074,671	
28	Case No. 16-00269-UT					
29						
30	Prepaid Retiree Medical		285,036	Various	185,522	99,514
31						
32	Texas DSM Incentives	1,503,974	592,068	Various	923,023	1,173,019
33						
34	FIN 48/ASC740-10 Interest	516,094	96,669	Various	612,763	
35						
36	Z2 Transmission Expense	8,941,444	208,151	Various	9,149,595	
37						
38	Texas Severed Rate Case Costs	797,124		928	797,124	
39	Docket No. 44498					
40	2 Year amortization ending					
41	July 2018					
42						
43	2017 TX TCRF	180,009	-199	928		179,810
44	Docket No. 46877					
45						
46	2017 TX Electric Rate Case	1,080,028	1,277,829	928	907,857	1,450,000
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	21,922,318				10,509,661

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Docket No. 47527					
2						
3	2017 NM Supreme Court Case	724	56,421	928	56,694	451
4	Case No. S-1-SC-36466					
5						
6	2017 NM Retail Rate Case	468,993	1,055,081	928	373,177	1,150,897
7	Case No. 17-00255-UT					
8						
9	Prepaid Facility Fees	1,206,297	15,000	431	360,780	860,517
10						
11	TX Electric 2017 Surcharge		26,056	928	7,039	19,017
12	Doc No. 47035					
13						
14	2018 TX Fuel Reconciliation		331,049			331,049
15	Docket No. 48973					
16						
17	Other Texas Dockets		67,648			67,648
18						
19	SPS TX 2019 Retail Rate Case		188,068			188,068
20						
21	SPS NM 2018 E Supreme		96,670			96,670
22	Court Case					
23	Case No. S-1-SC-37308					
24						
25	SPS NM 2019 Retail Rate Case		3,764			3,764
26						
27						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	21,922,318				10,509,661

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: c

This account is used to record an estimated impact of JOA allocations and estimated rate payer sharing on a forward Mark-to-Market position. Credit balances are adjustments and are not amortizations nor write-offs.

Schedule Page: 233 Line No.: 1 Column: e

This account is used to record an estimated impact of JOA allocations and estimated rate payer sharing on a forward Mark-to-Market position. Credit balances are adjustments and are not amortizations nor write-offs.

Schedule Page: 233 Line No.: 7 Column: e

Account charged:

143	552
146	16,796
181	480,151
	497,499

Schedule Page: 233 Line No.: 14 Column: c

Unnatural Debit Balance ($417,081)

The credit to the rate case expense account represents a reversal of previously deferred amounts. As such, it is a reduction of the deferred balance separate from amounts that have been amortized or written off.

Schedule Page: 233 Line No.: 17 Column: c

Unnatural Debit Balance ($14)

The credit to the rate case expense account represents a reversal of previously deferred amounts. As such, it is a reduction of the deferred balance separate from amounts that have been amortized or written off.

Schedule Page: 233 Line No.: 27 Column: c

Unnatural Debit Balance ($1,465)

The credit to the rate case expense account represents a reversal of previously deferred amounts. As such, it is a reduction of the deferred balance separate from amounts that have been amortized or written off.

Schedule Page: 233 Line No.: 30 Column: e

Account charged:

143	11,083
146	46,087
228.3	128,353
	185,522

Schedule Page: 233 Line No.: 32 Column: e

Account charged:

182.3	770,863
456	152,160
	923,023

Schedule Page: 233 Line No.: 34 Column: e

Account charged:

171	$	547,837
232		64,926
	$	612,763

Schedule Page: 233 Line No.: 36 Column: e

Account charged:

407.3	$	49,158
182.3		9,100,436
	$	9,149,595

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 43 Column: c

Unnatural Debit Balance ($199)

The credit to the rate case expense account represents a reversal of previously deferred amounts. As such, it is a reduction of the deferred balance separate from amounts that have been amortized or written off.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Unrecognized Tax Benefits	94,584	133,176
3	Electric Nonplant	63,755,339	49,048,650
4	Electric Plant	80,103,108	84,867,647
5	Regulatory Differences - Excess Deferred Plant Taxes	-33,954,345	-32,698,931
6	Regulatory Differences - Deferred ITC	59,612	44,640
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	110,058,298	101,395,182
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	2,310,162	-2
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	112,368,460	101,395,180

Notes

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 234 Line No.: 8 Column: c

	12/31/2017	12/31/2018
Regulatory Difference - Effect of Rate Changes	($33,954,345)	($33,175,437)
Average Rate Assumption Method Deferral	-	476,506
	(33,954,345)	(32,698,931)
Regulatory Difference - Investment Tax Credit Grossup	59,612	44,640
TOTAL Electric Plant Related Only	($33,894,733)	($32,654,291)

The amortization of Excess ADIT (Electric Only) included in 410.1 is $1,112,754.

	12/31/2018
Electric Distribution Plant	$507,045
Electric General Plant	29,680
Electric Intangible Plant	432
Electric Production Plant	139,301
Electric Transmission Plant	436,296
TOTAL Electric Amortization	$1,112,754

The Excess ADIT above in column C include the ungrossed amounts presented below. These amounts will be amortized over the books lives of the underlying assets.:

Excess (Electric only)	Excess 12/31/2018	Gross up 12/31/2018	Total Regulatory 12/31/2018
Flow Through	$281,971	$80,043	$362,014
Other Basis Differences (Unprotected)	(26,125,284)	(7,412,167)	(33,537,451)
TOTAL	($25,843,313)	($7,332,124)	($33,175,437)

	12/31/2017	12/31/2018
Electric Distribution Plant	$35,578,063	$36,158,388
Electric General Plant	924,534	948,926
Electric Production Plant	7,405,271	8,624,128
Electric Transmission Plant	36,027,060	38,972,736
Electric Transmission-Production Plant	168,180	163,469
Regulatory Difference - Excess Deferred Taxes	(33,954,345)	(32,698,931)
Regulatory Difference - Deferred ITC	59,612	44,640
TOTAL Electric Plant	$46,208,375	$52,213,356

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

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)
1	Account 201: Common Stock	200	1.00	
2	All SPS Common Stock owned by its parent,			
3	Xcel Energy			
4				
5				
6				
7	Total Common	200		
8				
9	Account 204: Preferred Stock	10,000,000	1.00	
10				
11				
12				
13				
14				
15	Total Preferred	10,000,000		
16				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (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 non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
100	100					1
						2
						3
						4
						5
						6
100	100					7
						8
						9
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on 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.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Miscellaneous paid-in capital	1,579,192,171
2		
3		
4		
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40	TOTAL	1,579,192,171

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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
2		
3		
4		
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22	TOTAL	9,033,435

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2	3.70% Aug 15, 2047 First Mortgage Bonds	450,000,000	5,056,507
3			2,587,500 D
4	3.40% Aug 15, 2046 First Mortgage Bonds	300,000,000	3,511,006
5			507,000 D
6	4.40% Nov 15, 2048 First Mortgage Bonds	300,000,000	3,105,151
7			1,935,000 D
8	4.50% Aug 15, 2041 Secured First Mortgage Bonds	200,000,000	3,848,628
9			3,014,000 D
10	4.50% Aug 15, 2041 Secured First Mortgage Bonds	100,000,000	1,380,528
11			-10,058,000 P
12	4.50% Aug 15, 2041 Secured First Mortgage Bonds	100,000,000	1,307,249
13			4,088,000 D
14	3.30% Jun 15, 2024 Secured First Mortgage Bonds	150,000,000	1,445,554
15			495,000 D
16	3.30% Jun 15, 2024 Secured First Mortgage Bonds	200,000,000	2,028,826
17			-596,000 P
18	Total Account 221	1,800,000,000	23,655,949
19			
20	Account 224 - Other Long Term Debt		
21			
22	6.00% Oct 1, 2033 Unsecured Series C and D Senior Notes	100,000,000	1,237,091
23			810,000 D
24	6.00% Oct 1, 2036 Unsecured Series F Senior Notes	250,000,000	2,596,882
25			1,922,500 D
26			
27	Total Account 224	350,000,000	6,566,473
28			
29	Interest on Debt to Associated Companies		
30			
31			
32			
33	TOTAL	2,150,000,000	30,222,422

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
	/					1
08/09/2017	08/15/2047	08/09/2017	08/15/2047	450,000,000	16,650,000	2
						3
8/12/2016	8/15/2046	8/12/2016	8/15/2046	300,000,000	10,200,000	4
						5
11/05/2018	11/15/2048	11/05/2018	11/15/2048	300,000,000	2,053,333	6
						7
8/10/2011	8/15/2041	8/10/2011	8/15/2041	200,000,000	9,000,000	8
						9
6/12/2012	8/15/2041	6/12/2012	8/15/2041	100,000,000	4,500,000	10
						11
8/20/2013	8/15/2041	8/20/2013	8/15/2041	100,000,000	4,500,000	12
						13
6/09/2014	6/15/2024	6/09/2014	6/15/2024	150,000,000	4,950,000	14
						15
9/16/2015	6/15/2024	9/16/2015	6/15/2024	200,000,000	6,600,000	16
						17
				1,800,000,000	58,453,333	18
						19
						20
						21
10/6/2003	10/1/2033	10/6/2003	10/1/2033	100,000,000	6,063,162	22
						23
10/6/2006	10/1/2036	10/6/2006	10/1/2036	250,000,000	15,000,000	24
						25
						26
				350,000,000	21,063,162	27
						28
					1,071,156	29
						30
						31
						32
				2,150,000,000	80,587,651	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 6 Column: a

New Mexico Public Regulation Commission case no. 18-00232-UT. Order dated Sep. 5, 2018.

SPS issued $300 million of 4.40 percent First Mortgage Bond due Nov. 15, 2048. SPS used a portion of the net proceeds to repay short-term debt and general corporate purposes.

Schedule Page: 256 Line No.: 22 Column: i

Interest at stated rate	$6,000,000
Interest swap loss	$63,162
	$6,063,162

Schedule Page: 256 Line No.: 29 Column: i

Xcel Energy Services Inc	$504,026
Money Pool	$567,130
	$1,071,156

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)	213,320,225
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote for Details	16,667,622
6		
7	Reconciling Items for the Year: Total Income Tax Expense	38,893,292
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote for Details	302,629,313
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote for Details	-19,105,607
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote for Details	-489,917,135
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	62,487,710
28	Show Computation of Tax:	
29	Federal Income Tax @ 21%	13,122,419
30		
31	Other	-334,691
32		
33	TOTAL Net Federal Income Tax Accrual	12,787,728
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Taxable Income Not Reported On Books	
Provision for Contributions in Aid of Construction	16,667,622
Total to Page 261	16,667,622

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted For Return	
Avoided Cost Interest	16,405,150
Book Depreciation Provision	196,267,026
Clearing Account Book Expense	5,899,762
Book Unamortized Cost of Reacquired Debt	800,520
Contributions Carryover	407,993
Deferred Compensation Plan Reserve	662,658
Deferred Fuel Costs	11,715,991
Employee Stock Ownership Plan Dividends	689,761
Interest Income/Expense on Disputed Tax	121,492
Litigation Reserve	1,235,383
Lobbying Expenses	794,000
Meals and Entertainment	383,000
Penalties	32,701
Pension Expense	6,725,631
Performance Recognition Awards	707
Rate Case / Restructuring	11,311,625
Rate Refund Reserve	10,130,845
Recoverable Meters Provision	34,898
Regulatory Asset / Liability - Transmission Attach O	18,578,354
Renewable Energy Standard/Credit	5,277,256
Section 174 - Section 59(e) Adjustment	14,959,768
State Tax Deduction	192,792
Suite / Entertainment Tickets	2,000
Total to Page 261	302,629,313

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded On Books Not Included In Return	
Allowance for Funds During Construction (AFDC) - Equity	(19,093,073)
Deferred Revenue (ITC Grant Accounting)	(12,534)
Total to Page 261	(19,105,607)

Schedule Page: 261 Line No.: 20 Column: b

Deductions On Return Not Charged Against Book Income	
Allowable Depreciation	(193,933,514)
Allowance for Funds During Construction (AFDC) - Debt	(8,954,845)
Bad Debts	(733,415)
Employee Incentive	(241,753)
Environmental Remediation	(13,950)
Federal Net Operating Loss Benefit	(177,176,520)
Gain/(Loss) on Disposition of Assets (Book)	(73,373)
Gain/(Loss) on Disposition of Assets (Tax)	(1,633,671)
Internally Developed Software	(167,007)
Inventory Reserve	(68,090)
Mark-to-Market Adjustment	(420,191)
Non-Qualified Pension Plan	(67,833)
Pension & Benefits Capitalized	(1,272,179)
Performance Share Plan	(162,779)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Post Employment Benefit - Long Term Disability	(159,517)
Post Employment Benefit - Retiree Medical	(544,716)
Regulatory Asset - Miscellaneous	(6,868,998)
Regulatory Asset - New Mexico Nitric Oxide (NOX)	(2,340)
Regulatory Asset - Texas Surcharge	(5,294,592)
Repair Expenditures	(43,595,558)
Section 174 Expenditures	(19,400,000)
Tax Removal Cost Over Book	(29,049,728)
Vacation Accrual	(82,566)
Total to Page 261	(489,917,135)

Schedule Page: 261 Line No.: 33 Column: b

Southwestern Public Service Company is a member of an affiliated group which will file a consolidated federal income tax return for the year 2018. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	(85,716,992)
Northern States Power Company (Minnesota) and Subsidiaries	(15,614,605)
Northern States Power Company (Wisconsin) and Subsidiaries	7,902,487
Public Service Company of Colorado and Subsidiaries	80,987,999
Nicollet Holdings Company, LLC and Subsidiaries	930,173
Nicollet Projects Holdings Company, LLC and Subsidiaries	(1,416,427)
Xcel Energy Communications Group Inc. and Subsidiaries	(164,433)
Xcel Energy Markets Holdings Inc. and Subsidiaries	56,217
Xcel Energy International Inc.	25,228
Xcel Energy Retail Holdings Inc. and Subsidiaries	(606,576)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(578,355)
Xcel Energy Ventures Inc. and Subsidiaries	(129,396)
Xcel Energy Venture Holdings, Inc. and Subsidiaries	(484,103)
Xcel Energy Wholesale Group Inc. and Subsidiaries	(44,469,021)
Xcel Energy WYCO Inc.	5,385,236
WestGas Interstate, Inc.	28,633
Xcel Energy Services Inc.	13,671,640

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	Income (2141001)	3,632,263		12,266,829	10,821,022	4,183,824
3	Income Tax Adjustment			520,899		-520,899
4	2017 Federal Unemployment	596			596	
5	2018 Federal Unemployment			52,567	51,741	
6	2017 FICA (2046001)				544,126	
7	2018 FICA (2146001)	544,126		8,368,757	7,815,688	-46
8	SUBTOTAL	4,176,985		21,209,052	19,233,173	3,662,879
9						
10	STATE:					
11	2017 State Unemployment	1,885			1,885	
12	2018 State Unemployment			78,628	76,437	
13	SUBTOTAL	1,885		78,628	78,322	
14						
15	TEXAS:					
16	Income (2141011)	2,605,488		1,856,174	1,064,761	-518,996
17	Income Tax Adjustment			183,758		-183,758
18	Franchise					
19	Use (2145001)	817,034		7,569,165	6,777,385	
20	2017 Property Tax (2144001)	21,700,877		-1,253,941	20,446,936	
21	2018 Property Tax (2144001)			34,302,784	12,649,170	437,216
22	Gross Receipts (1244001)			6,463,444	6,463,444	
23	SUBTOTAL	25,123,399		49,121,384	47,401,696	-265,538
24						
25	NEW MEXICO:					
26	Income (2141011)		870,460	395,456	-1,265,299	375,195
27	Income Tax Adjustment					
28	Franchise					
29	Use (2145001)	1,163,312		4,873,574	6,956,984	
30	2017 Property Tax (2144001)	3,670,177		400,935	4,071,112	
31	2018 Property Tax (2144001)			8,164,044	4,414,024	715,956
32	SUBTOTAL	4,833,489	870,460	13,834,009	14,176,821	1,091,151
33						
34	OKLAHOMA:					
35	Income (2141011)	11,508		57,129		28
36	Income Tax Adjustment					
37	Franchise (1244001)			20,000	20,000	
38	Use (2145001)			98		
39	2017 Property Tax (2144001)					
40	2018 Property Tax (2144001)			594,455	594,455	
41	TOTAL	35,523,161	870,460	95,540,952	92,196,739	4,500,312

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	SUBTOTAL	11,508		671,682	614,455	28
2						
3	KANSAS:					
4	Income (2141011)	7,966		32,775	7,746	14,456
5	Income Tax Adjustment					
6	Franchise (386970.02)					
7	Use (2145001)			16,019	16,019	
8	2017 Property Tax (2144001)					
9	2018 Property Tax (2144001)			1,031,950	1,031,950	
10	SUBTOTAL	7,966		1,080,744	1,055,715	14,456
11						
12	OTHER:					
13	Miscellaneous Use Tax			306,944	306,944	
14	City Franchise Fees	1,367,929		9,238,509	9,329,613	-2,664
15	SUBTOTAL	1,367,929		9,545,453	9,636,557	-2,664
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	TOTAL	35,523,161	870,460	95,540,952	92,196,739	4,500,312

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
9,261,894		14,711,556			-2,444,727	2
		520,899				3
						4
826		56,436			-3,869	5
						6
553,023		8,491,968			-123,211	7
9,815,743		23,780,859			-2,571,807	8
						9
						10
						11
2,191		106,837			-28,209	12
2,191		106,837			-28,209	13
						14
						15
2,877,905		1,856,174				16
		183,758				17
						18
1,608,814		47,449			7,521,716	19
		-1,253,941				20
22,090,830		34,290,784			12,000	21
		6,463,444				22
26,577,549		41,587,668			7,533,716	23
						24
						25
1,165,490		423,161			-27,705	26
						27
						28
-920,098		8,133			4,865,441	29
		400,935				30
4,465,976		8,164,044				31
4,711,368		8,996,273			4,837,736	32
						33
						34
68,665		57,760			-631	35
						36
		20,000				37
98					98	38
						39
		594,455				40
42,497,226		85,761,172			9,779,780	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
68,763		672,215			-533	1
						2
						3
47,451		33,212			-437	4
						5
						6
					16,019	7
						8
		1,031,950				9
47,451		1,065,162			15,582	10
						11
						12
		313,649			-6,705	13
1,274,161		9,238,509				14
1,274,161		9,552,158			-6,705	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
42,497,226		85,761,172			9,779,780	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: f

Federal income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	$ 444,715
Federal income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	3,711,718
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	27,391
	$ 4,183,824

Schedule Page: 262 Line No.: 2 Column: l

Federal non-operating income tax - non-utility (409.2)	$ (2,444,727)
	$ (2,444,727)

Schedule Page: 262 Line No.: 3 Column: f

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$(757,406)
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	$236,507
	$(520,899)

Schedule Page: 262 Line No.: 5 Column: l

FICA taxes charged to capital, clearing and deferred accounts (107,184,186)	(3,938)
Federal Unemployment Non Utility (408.2)	69
	$ (3,869)

Schedule Page: 262 Line No.: 7 Column: f

FICA taxes charged to capital, clearing and deferred accounts (107,184,186)	$ (46)
	$ (46)

Schedule Page: 262 Line No.: 7 Column: l

FICA taxes charged to capital, clearing and deferred accounts (107,184,186)	$(133,393)
Payroll Taxes Non Utility (408.2)	$10,182
	$(123,211)

Schedule Page: 262 Line No.: 12 Column: l

State Unemployment charged to capital , clearing and deferred accounts (107,184,186)	$(28,358)
State Unemployment Non Utility (408.2)	$149
	$(28,209)

Schedule Page: 262 Line No.: 16 Column: f

Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	(518,996)
	$ (518,996)

Schedule Page: 262 Line No.: 17 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$ (349,649)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	165,891
	$ (183,758)

Schedule Page: 262 Line No.: 19 Column: l

Texas use tax accrued on taxable materials and services	$7,521,716
	$7,521,716

Schedule Page: 262 Line No.: 21 Column: f

Texas property tax on CWIP reclassified to a capital asset	437,216
	$ 437,216

Schedule Page: 262 Line No.: 21 Column: l

Property Taxes - Non Utility (408.2)	12,000
	$ 12,000

Schedule Page: 262 Line No.: 26 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$1,078
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	374,117
	$375,195

Schedule Page: 262 Line No.: 26 Column: l

State non-operating income tax - non-utility (409.2)	$(27,705)
	$(27,705)

Schedule Page: 262 Line No.: 29 Column: l

New Mexico use tax accrued on taxable materials and services.	$4,865,442
	$4,865,442

Schedule Page: 262 Line No.: 31 Column: f

New Mexico property tax on CWIP reclassified to a capital asset	$ 715,956
	$ 715,956

Schedule Page: 262 Line No.: 35 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	28
	$ 28

Schedule Page: 262 Line No.: 35 Column: l

State non-operating income tax - non-utility (409.2)	$ (631)
	$ (631)

Schedule Page: 262 Line No.: 38 Column: l

Oklahoma use tax accrued on taxable materials and services	$ 98
	$ 98

Schedule Page: 262.1 Line No.: 4 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$ 12
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	14,444
	$ 14,456

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 262.1 Line No.: 4 Column: l

State non-operating income tax - non-utility (409.2)	$	(437)
	$	(437)

Schedule Page: 262.1 Line No.: 7 Column: l

Kansas use tax accrued on taxable materials and services	$ 16,019
	$ 16,019

Schedule Page: 262.1 Line No.: 14 Column: f

City franchise fee adjustments - Franchise Fees (408.1) tax collections payable (241)	$	(2,664)
	$	(2,664)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Retail	209,706			411.4	52,421	
7							
8	TOTAL	209,706				52,421	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
157,285	41.5 Years		6
			7
157,285			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
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			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

OTHER DEFFERED 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	2,025,072	Various	140,884	803,541	2,687,729
2						
3	Remediation Costs	65,000	242	15,000		50,000
4						
5	Executive PSP Long Term	359,703	Various	274,526	134,703	219,880
6						
7	Long-term Income Tax and	5,639,233	Various	5,216,847	724,642	1,147,028
8	Interest Payable					
9						
10	Deferred Revenue - ITC Grant	219,347	417.1	12,535		206,812
11	25 year amortization beginning					
12	2010 and ending 2035					
13						
14	Miscellaneous Deferred Credit	4,690,169	158.1	3,526,205	3,521,721	4,685,685
15						
16	Customer Prepayments	968,417	Various	988,058	166,069	146,428
17	-Capital CIAC					
18						
19	Deferred Revenue for Tax	3,273,488	405	198,142	1,020,739	4,096,085
20	Liability CIAC					
21						
22						
23						
24						
25						
26						
27						
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37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	17,240,429		10,372,197	6,371,415	13,239,647

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 1 Column: c

Contra Account (c)	Amount (d)
131	$ 60,717
920	80,167
	$ 140,884

Schedule Page: 269 Line No.: 5 Column: c

Contra Account (c)	Amount (d)
232	$ 158,573
253	115,953
	$ 274,526

Normal reclasses occur within FERC 253 when balances are transferred from Deferred PSP liability account 2421051 to Deferred Comp liability account 2421026.

Schedule Page: 269 Line No.: 7 Column: c

Contra Account (c)	Amount (d)
236	$ 3,676,299
237	656,898
409.1	883,389
409.2	261
	$ 5,216,847

Schedule Page: 269 Line No.: 16 Column: c

Contra Account (c)	Amount (d)
107	$ 965,967
561.6	20,810
588	1,281
	$ 988,058

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	1,155,476	-28,421	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	1,155,476	-28,421	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	1,155,476	-28,421	
18	Classification of TOTAL			
19	Federal Income Tax	1,106,454	-27,249	
20	State Income Tax	49,022	-1,172	
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						1,127,055	4
							5
							6
							7
						1,127,055	8
							9
							10
							11
							12
							13
							14
							15
							16
						1,127,055	17
							18
						1,079,205	19
						47,850	20
							21

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 272 Line No.: 8 Column: b

All amounts in columns b - k are related to Electric Steam Production Plant

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFFERED 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,150,013,735	25,807,857	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,150,013,735	25,807,857	
6	Regulatory Difference - Prior	-574,442,594		
7	Regulatory Difference - AFUDC	23,887,530		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	599,458,671	25,807,857	
10	Classification of TOTAL			
11	Federal Income Tax	541,933,907	23,243,945	
12	State Income Tax	57,524,764	2,563,912	
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						1,175,821,592	2
							3
							4
						1,175,821,592	5
		254	872,516	254	5,723,616	-569,591,494	6
				182.3	3,995,027	27,882,557	7
							8
			872,516		9,718,643	634,112,655	9
							10
					9,499,103	574,676,955	11
			872,516		219,540	59,435,700	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 6 Column: b

Prior Flow Through

Schedule Page: 274 Line No.: 6 Column: k

The Excess ADIT 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)	Excess 12/31/2018	Gross up 12/31/2018	Total Regulatory 12/31/2018
Flow Through	($424,075)	($120,382)	($544,457)
Method Life (Protected)	(363,505,626)	(103,187,779)	(466,693,405)
Other Basis Differences (Unprotected)	(79,722,834)	(22,630,798)	(102,353,632)
TOTAL	($443,652,535)	($125,938,959)	($569,591,494)

The amortization of excess ADIT included above in 410.1 is $11,634,011.

	12/31/2018
Electric Distribution Plant	$2,157,362
Electric General Plant	2,007,697
Electric Intangible Plant	1,092,839
Electric Production Plant	4,235,071
Electric Transmission Plant	2,141,042
TOTAL Electric Amortization	$11,634,011

Schedule Page: 274 Line No.: 7 Column: b

AFUDC Equity

Schedule Page: 274 Line No.: 9 Column: k

	12/31/2017	410.1 & Adjustments	12/31/2018
Electric Distribution Plant	$265,820,176	($2,637,840)	$263,182,336
Electric General Plant	61,713,446	(1,921,988)	59,791,458
Electric Intangible Plant	970,870	378,025	1,348,895
Electric Production Plant	269,913,216	2,686,503	272,599,719
Electric Transmission Plant	541,854,048	29,402,261	571,256,309
Electric Transmission-Production Plant	4,740,119	(161,574)	4,578,545
Non-Utility	5,001,860	(1,937,530)	3,064,330
Regulatory Difference - Prior Flow Thru/Rate Change	(574,442,594)	4,851,100	(569,591,494)
Regulatory Difference - AFUDC Equity	23,887,530	3,995,027	27,882,557

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

TOTAL Electric Plant	$599,458,671	$34,653,984	$634,112,655

FERC Account	Description	Page No.	Plant-Related Ending Balance
282	Accumulated Deferred Income Taxes - Other Property	275	634,112,655
Less: Non-utility Accumulated Deferred Income Taxes			(3,064,330)
Unblended ADIT Adjustment Total Company - Wholesale Jurisdiction			(38,632,356)
Wholesale Jurisdiction Accumulated Deferred Income Taxes			592,415,969

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFFERED 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric Non-Plant	57,778,844	9,831,824	22,187,640
4	Electric Plant	25,295,204	1,301,782	
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	83,074,048	11,133,606	22,187,640
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Non-Operating	-244,625		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	82,829,423	11,133,606	22,187,640
20	Classification of TOTAL			
21	Federal Income Tax	78,784,117	10,503,158	21,361,035
22	State Income Tax	4,045,306	630,448	826,605
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
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)	Line No.
							1
							2
		254	17,898,591	various	29,055,628	56,580,065	3
						26,596,986	4
							5
							6
							7
							8
			17,898,591		29,055,628	83,177,051	9
							10
							11
							12
							13
							14
							15
							16
							17
						-244,625	18
			17,898,591		29,055,628	82,932,426	19
							20
			17,898,591		29,055,628	79,083,277	21
						3,849,149	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 3 Column: i

254 & 219.1

Schedule Page: 276 Line No.: 4 Column: b

	12/31/2017	410.1	12/31/2018
Electric General Plant	$228,217	($15,086)	$213,131
Electric Intangible Plant	25,066,987	1,316,868	26,383,855
TOTAL Electric Plant	$25,295,204	$1,301,782	$26,596,986

Schedule Page: 276 Line No.: 19 Column: k

Refer to FERC page 278 for SPS's regulatory liability related to nonplant excess ADIT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Deferred Investment Tax Credit	59,614	190	14,973		44,641
2						
3	Texas Fuel Costs Recovered via FCR	20,351,823	557	310,436,699	316,063,777	25,978,901
4						
5	New Mexico Fuel Costs - NMPRC	28,108,056	557	139,276,724	141,702,116	30,533,448
6	Rule 550 - Recovered via FPPCAC					
7						
8	DSM Texas Energy Efficiency		Various	4,731,971	4,883,633	151,662
9	Docket 48324					
10						
11	Attachment "O" Transmission Refund	13,327,843	Various	11,660,422	10,006,862	11,674,283
12						
13	2018 Production Formula True Up		447	11,919	7,815,227	7,803,308
14						
15	Retiree Medical Liability	10,849,172	Various	857,000	1,405,284	11,397,456
16						
17	Sale of Lubbock Distribution Assets:	2,476,407	407.4	53,949		2,422,458
18	Incremental Capital Expenditures and Other					
19	- Amortized over the life of the asset					
20	Docket #37901					
21						
22	SO2 Reserve	5,440	411.8	5,439	17	18
23	Docket #08-00354-UT					
24						
25	FAS 133-Electric Hedges	12,723,176			1,935,277	14,658,453
26						
27	New Mexico RPS Rider		Various	3,080,115	5,518,996	2,438,881
28	Case #18-00201-UT					
29						
30	Prior Flow Thru and Excess ADIT	540,641,955	Various	5,769,435	3,806,545	538,679,065
31						
32	Nonplant Excess ADIT	27,980,591	190	6,902,081	1,938,598	23,017,108
33						
34	New Mexico Tax Cuts and Jobs Act				10,190,215	10,190,215
35	Refund Case # 17-00255-UT					
36						
37						
38						
39						
40						
41	TOTAL	656,524,077		482,800,727	505,266,547	678,989,897

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 8 Column: d

456	$	3,632
182.3	$	77,709
908	$	770,863
456	$	13,240
Various	$	3,866,526
	$	4,731,971

DSM Program costs are deferred to account 1403001 and offset various FERC accounts through Settlements.

Schedule Page: 278 Line No.: 11 Column: d

431	$	85,587
456.1	$	10,015,204
565	$	1,559,630
	$	11,660,422

Schedule Page: 278 Line No.: 15 Column: d

228.3	$	299,000
926	$	558,000
	$	857,000

Schedule Page: 278 Line No.: 27 Column: d

182.3	$	1,299,920
557	$	1,780,195
	$	3,080,115

Schedule Page: 278 Line No.: 30 Column: d

182.3		45,820
282		5,723,615
	$	5,769,435

Schedule Page: 278 Line No.: 32 Column: b

Electric	$ 29,453,253
Reserve	(1,472,662)
	$ 27,980,591

The total related to nonplant excess ADIT is $29,453,253. This amount would be included as a decrease to rate base for purposes of calculating SPS formula rates, as applicable.

Schedule Page: 278 Line No.: 32 Column: f

	Excess Nonplant ADIT - Regulatory Liability*	Gross-Up	Reserves (Net of Gross-Up)	Total
Electric	$19,074,592	$5,414,675	$(1,472,159)	$23,017,108

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

FOOTNOTE DATA

Total	$19,074,592	$5,414,675	$(1,472,159)	$23,017,108

*Total nonplant excess ADIT is $19,074,592. This amount would be included as a decrease to rate base for purposes of calculating SPS formula rates, as applicable.

The Nonplant Excess Accumulated deferred Income Taxes above include the following ungrossed amounts:

Book Unamortized Cost of Reacquired Debt	$2,941,267
Pension Expense	$17,488,728
Rate Case / Restructuring Expense	$2,315,093
Regulatory Asset - New Mexico Nitric Oxide (NOX)	$4,492
State Tax Deduction	$175,345
Total Electric	$22,924,925

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	376,525,460	367,234,279
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	377,998,521	375,961,000
5	Large (or Ind.) (See Instr. 4)	474,205,317	516,786,467
6	(444) Public Street and Highway Lighting	7,043,700	7,806,757
7	(445) Other Sales to Public Authorities	39,101,436	40,238,124
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,274,874,434	1,308,026,627
11	(447) Sales for Resale	396,011,244	350,554,091
12	TOTAL Sales of Electricity	1,670,885,678	1,658,580,718
13	(Less) (449.1) Provision for Rate Refunds		3
14	TOTAL Revenues Net of Prov. for Refunds	1,670,885,678	1,658,580,715
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,660,527	1,942,215
17	(451) Miscellaneous Service Revenues	1,158,183	1,016,876
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	8,553,339	8,535,238
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-9,549,747	-9,124,066
22	(456.1) Revenues from Transmission of Electricity of Others	222,965,402	216,191,760
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	224,787,704	218,562,023
27	TOTAL Electric Operating Revenues	1,895,673,382	1,877,142,738

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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 pages 108-109, 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.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
3,645,138	3,355,918	307,894	305,897	2
				3
5,040,877	4,700,919	77,275	77,362	4
11,214,454	10,721,063	227	224	5
47,250	47,267	116	116	6
502,781	480,133	6,202	6,214	7
				8
				9
20,450,500	19,305,300	391,714	389,813	10
10,077,040	7,818,763	7	7	11
30,527,540	27,124,063	391,721	389,820	12
				13
30,527,540	27,124,063	391,721	389,820	14

Line 12, column (b) includes $ -5,684,803 of unbilled revenues.
Line 12, column (d) includes -11,705 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 2 Column: b

Current Year

		Billed Revenue	Unbilled Revenue	Total
Residential	**440**	379,117,026	(2,591,566)	**376,525,460**
Small C&l	**442**	379,546,597	(1,548,076)	**377,998,521**
Large C&l	**442**	477,079,551	(2,874,233)	**474,205,318**
PSHL	**444**	7,068,444	(24,745)	**7,043,699**
OSPA	**445**	39,397,553	(296,117)	**39,101,436**
Resale	**447**	394,361,311	1,649,934	**396,011,245**
		$1,676,570,482	(5,684,803)	**1,670,885,679**

This note applies to column (b), rows 2,4,5,6,7, and 11

Schedule Page: 300 Line No.: 2 Column: c

Previous Year

		Billed Revenue	Unbilled Revenue	Total
Residential	**440**	366,844,227	390,052	**367,234,279**
Small C&l	**442**	374,523,815	1,437,185	**375,961,000**
Large C&l	**442**	515,350,541	1,435,926	**516,786,467**
PSHL	**444**	7,649,351	157,406	**7,806,757**
OSPA	**445**	40,372,108	(133,984)	**40,238,124**
Resale	**447**	374,003,816	(23,449,725)	**350,554,091**
		$1,678,743,858	(20,163,140)	**1,658,580,718**

This note applies to column (c), rows 2,4,5,6,7, and 11

Schedule Page: 300 Line No.: 5 Column: b

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.

Schedule Page: 300 Line No.: 5 Column: c

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.

Schedule Page: 300 Line No.: 12 Column: b

Includes -5,684,803 unbilled revenues

Schedule Page: 300 Line No.: 12 Column: d

Includes (11,705) MWH relating to unbilled revenues.

Schedule Page: 300 Line No.: 13 Column: c

No provisions in 2017 or 2018.

Schedule Page: 300 Line No.: 17 Column: b

Account charged:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Customer Connections	$	883,167
Return Check Charge		199,303
Penalties		-
Other		75,713
	$	**1,158,183**

Schedule Page: 300 Line No.: 17 Column: c

Account charged:

Customer Connections	$	570,670
Return Check Charge		191,172
Penalties		236,532
Other		18,502
	$	**1,016,876**

Schedule Page: 300 Line No.: 21 Column: b

	Previous Year
Mutual Aid	$ 4,233,339
JOA Margin Sharing	3,478,491
Distrib Service Charge-Coops-Whl	1,116,077
CIP/DSM Incentive	(330,955)
Deferred Fuel Revenue	(8,052,470)
NM TCJA Accrual	(10,190,215)
MISC Other	195,986
	$ (9,549,747)

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).

Schedule Page: 300 Line No.: 21 Column: c

	Previous Year
JOA Margin Sharing	$ 2,678,632
PUC Docket Number 45524 Refund	1,309,748
Mutual Aid	1,048,940
Demand Power Factor Accrual	956,075
Distrib Service Charge-Coops-Whl	688,750
Deferred Fuel Revenue	(16,008,927)
MISC Other	202,716
	$ (9,124,066)

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).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)
1					
2					
3					
4					
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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 Residential Flood Lighting	100	12,842	33	3,030	0.1284
2	TX Residential Guard Lighting	6,061	1,491,732	7,936	764	0.2461
3	TX Res Ltg Space Heat	555,573	50,339,309	30,682	18,107	0.0906
4	TX Residential	1,951,855	210,900,288	173,280	11,264	0.1081
5	TX Residential Time of Use	665	67,617	42	15,833	0.1017
6	NM Res Area Lighting	5,024	1,090,033	6,335	793	0.2170
7	NM Residential Heating	494,923	45,833,469	29,711	16,658	0.0926
8	NM Residential Lighting	651,626	69,366,188	59,865	10,885	0.1065
9	NM Residential Heating Time of Us	67	5,390	3	22,333	0.0804
10	NM Residential Time of Use	102	10,158	7	14,571	0.0996
11	Residential Unbilled	-20,858	-2,591,566			0.1242
12	TOTAL RESIDENTIAL	3,645,138	376,525,460	307,894	11,839	0.1033
13						
14	NM Commercial Area Lighting	10,490	1,461,817	2,757	3,805	0.1394
15	TX Flood Lighting	11,232	1,404,525	1,197	9,383	0.1250
16	TX Guard Lighting	6,742	1,665,921	4,329	1,557	0.2471
17	NM General Service Time of Use	204	29,214	1	204,000	0.1432
18	TX General Serv Secondary Low Loa	1,257	289,082	1	1,257,000	0.2300
19	TX Gen Svc Experimental TOU	93,243	6,299,294	39	2,390,846	0.0676
20	NM Irrigation	78,266	6,674,500	1,012	77,338	0.0853
21	NM Large Gen Serv Trans - 115 kV	2,062,088	84,797,496	22	93,731,273	0.0411
22	NM Large Gen Backbone Svc	2,159	422,288	2	1,079,500	0.1956
23	TX Large Gen Serv Trans - 115 kV	5,441,752	213,888,111	46	118,298,957	0.0393
24	NM Large Gen Serv Trans - 69 kV	157,605	7,004,443	5	31,521,000	0.0444
25	TX Large Gen Serv Subtran - 69 kV	627,434	25,031,842	10	62,743,400	0.0399
26	NM Primary General	1,289,254	73,863,918	535	2,409,821	0.0573
27	NM Primary General Oil Well Pumpi	369,102	30,747,470	4,271	86,421	0.0833
28	NM Primary General Standby	450	15,379	4	112,500	0.0342
29	TX Primary General	1,654,335	85,801,637	510	3,243,794	0.0519
30	TX Primary General Oil Well Pumpi	375,321	22,942,296	3,153	119,036	0.0611
31	TX Primary Qualifying Fac	140	71,408	9	15,556	0.5101
32	SAS-12 WRB Refining	497,639	20,315,755	1	497,639,000	0.0408
33	SAS-4 Canadian River Water Auth	137,497	6,195,025	1	137,497,000	0.0451
34	SAS-8 JM Huber	32,440	1,332,710	1	32,440,000	0.0411
35	NM Secondary General	727,706	57,789,707	3,639	199,974	0.0794
36	NM Small General Service	157,530	14,580,010	11,666	13,503	0.0926
37	TX Small General Service	305,745	29,345,904	32,542	9,395	0.0960
38	TX Secondary General	2,137,017	160,880,423	11,747	181,920	0.0753
39	TX Trans QF Standby - 115kV	54,865	3,369,938	1	54,865,000	0.0614
40	TX Trans QF Standby - 69kV	425	406,034	1	425,000	0.9554
41	TOTAL Billed	20,449,854	1,282,209,170	391,714	52,206	0.0627
42	Total Unbilled Rev.(See Instr. 6)	646	-7,334,736	0	0	-11.3541
43	TOTAL	20,450,500	1,274,874,434	391,714	52,208	0.0623

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	SM/LG C&I Unbilled	23,393	-4,422,309			-0.1890
2	TOTAL COMMERCIAL &	16,255,331	852,203,838	77,502	209,741	0.0524
3						
4	TX SA-810 Street and Hwy Ltg	50	6,140	3	16,667	0.1228
5	TX SA-805 Amarillo Hwy Ltg	107	5,980	2	53,500	0.0559
6	TX Street Ltg Restricted Outdoor	33,744	4,728,724	92	366,783	0.1401
7	NM Street Lighting	13,354	2,327,601	19	702,842	0.1743
8	PS & HL Unbilled	-5	-24,745			4.9490
9	TOTAL PUBLIC STREET & HWY	47,250	7,043,700	116	407,328	0.1491
10						
11	TX Large Municipal	156,525	10,020,904	884	177,064	0.0640
12	TX Large School Service	162,774	14,572,749	716	227,338	0.0895
13	TX Small Municipal & School	21,112	2,072,658	2,855	7,395	0.0982
14	TX Large Municipal Primary	28,633	1,910,633	13	2,202,538	0.0667
15	TX Large School Primary	2,866	203,044	4	716,500	0.0708
16	NM Large Municipal & School	116,818	9,267,729	545	214,345	0.0793
17	NM Small Municipal & School	11,732	1,023,696	1,174	9,993	0.0873
18	NM Large Municipal & School TOU	4,207	326,140	11	382,455	0.0775
19	OSPA Unbilled	-1,886	-296,117			0.1570
20	TOTAL PUBLIC AUTHORITY	502,781	39,101,436	6,202	81,068	0.0778
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41	TOTAL Billed	20,449,854	1,282,209,170	391,714	52,206	0.0627
42	Total Unbilled Rev.(See Instr. 6)	646	-7,334,736	0	0	-11.3541
43	TOTAL	20,450,500	1,274,874,434	391,714	52,208	0.0623

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 21 Column: a

Schedule Page: 304.1 Line No.: 40 Column: c

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

NM Commercial Area Lighting	$	236,338
NM General Service Time of Use		4,476
NM Irrigation		1,695,067
NM Large Gen Serv Trans - 115 kV		42,939,968
NM Large Gen Serv Trans - 69 kV		3,295,005
NM Large Municipal & School		2,594,779
NM Large Municipal & School TOU		108,247
NM Primary General		28,349,533
NM Primary General Oil Well Pumping		8,467,130
NM Res Area Lighting		114,190
NM Residential Heating		11,191,834
NM Residential Heating Time of Use		1,307
NM Residential Lighting		14,497,067
NM Residential Time of Use		2,091
NM Secondary General		16,330,321
NM Small General Service		3,525,912
NM Small Municipal & School		264,712
NM Street Lighting		304,245
SAS-12 WRB Refining		9,969,558
SAS-4 Canadian River Water Auth		3,100,044
SAS-8 JM Huber		947,657
TX Flood Lighting		260,071
TX Gen Svc Experimental TOU		2,281,992
TX General Serv Secondary Low Load		29,248
TX Guard Lighting		156,177
TX Large Gen Serv Subtran - 69 kV		12,667,810
TX Large Gen Serv Trans - 115 kV		110,093,081
TX Large Municipal		3,599,994
TX Large Municipal Primary		645,160
TX Large School Primary		62,744
TX Large School Service		3,744,709
TX Primary General		36,665,912
TX Primary General Oil Well Pumping		8,384,058
TX Primary Qualifying Fac		764
TX Res Ltg Space Heat		12,666,948
TX Residential		43,572,136
TX Residential Flood Lighting		2,328
TX Residential Guard Lighting		140,212
TX Residential Time of Use		15,144
TX SA-805 Amarillo Hwy Ltg		2,504
TX SA-810 Street and Hwy Ltg		1,172
TX Secondary General		48,444,438
TX Small General Service		6,922,426
TX Small Municipal & School		485,284
TX Street Ltg Restricted Outdoor		787,680
TX Trans QF Standby - 115kV		910,159
TX Trans QF Standby - 69kV		21,695

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Total	$	440,503,327

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 326-327).
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.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Central Valley Elec Cooperative, Inc.	RQ	RS114	78	135	112
2	Farmers' Elec Cooperative Inc., of NM	RQ	RS115	41	65	50
3	Golden Spread Electric	RQ	RS135	0	0	0
4	Lea County Elec Cooperative, Inc.	RQ	RS116	139	205	164
5	Roosevelt County Elec Cooperative, Inc.	RQ	RS117	16	33	24
6	Tri-County Elec Cooperative	RQ	RS136	62	61	56
7	West Texas Municipal Power Agency	RQ	RS137	517	471	447
8	Southwest Power Pool	OS	V3	N/A	N/A	N/A
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
612,094	7,333,884	16,806,292	6,696,112	30,836,288	1
186,132	4,211,851	5,108,101	3,437,600	12,757,552	2
	510,000	-8,903	-404,101	96,996	3
870,432	13,148,541	23,823,596	10,830,412	47,802,549	4
88,493	1,416,842	2,478,129	1,444,006	5,338,977	5
382,453	5,799,925	10,477,797	3,192,670	19,470,392	6
2,973,735	49,448,287	81,240,506	29,227,070	159,915,863	7
4,963,701		109,560,785	10,231,842	119,792,627	8
					9
					10
					11
					12
					13
					14
5,113,339	81,869,330	139,925,518	54,423,769	276,218,617	
4,963,701	0	109,560,785	10,231,842	119,792,627	
10,077,040	**81,869,330**	**249,486,303**	**64,655,611**	**396,011,244**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 2 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 3 Column: j
Annual Formula True Up Estimates; GSEC was not a wholesale customer in 2018.

Schedule Page: 310 Line No.: 4 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 5 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 6 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 7 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 8 Column: b
SPP Market Transactions

Schedule Page: 310 Line No.: 8 Column: j
Transmission and Trading Revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,290,065	2,288,594
5	(501) Fuel	303,338,421	323,686,587
6	(502) Steam Expenses	10,894,158	10,130,024
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	10,203,419	10,446,776
10	(506) Miscellaneous Steam Power Expenses	13,365,874	12,411,817
11	(507) Rents	6,556,090	5,689,240
12	(509) Allowances	122,490	14,055
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	346,770,517	364,667,093
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,419,933	1,441,404
16	(511) Maintenance of Structures	5,469,723	5,212,439
17	(512) Maintenance of Boiler Plant	16,202,910	15,694,431
18	(513) Maintenance of Electric Plant	10,402,049	10,780,047
19	(514) Maintenance of Miscellaneous Steam Plant	11,082,554	11,524,959
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	44,577,169	44,653,280
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	391,347,686	409,320,373
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-Nuc. Power (Entr tot 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 (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	32,100	130,914
63	(547) Fuel	40,552,886	17,655,722
64	(548) Generation Expenses	575,073	418,920
65	(549) Miscellaneous Other Power Generation Expenses	347,615	369,686
66	(550) Rents	498,229	330,621
67	TOTAL Operation (Enter Total of lines 62 thru 66)	42,005,903	18,905,863
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	214,330	131,087
70	(552) Maintenance of Structures	405,846	406,896
71	(553) Maintenance of Generating and Electric Plant	1,537,201	2,532,725
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	248,064	118,627
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,405,441	3,189,335
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	44,411,344	22,095,198
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	479,246,323	494,888,677
77	(556) System Control and Load Dispatching	1,108,043	1,285,668
78	(557) Other Expenses	11,792,804	5,595,970
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	492,147,170	501,770,315
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	927,906,200	933,185,886
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	9,363,000	8,502,564
84			
85	(561.1) Load Dispatch-Reliability	214,751	139,876
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,243,101	3,223,494
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	4,019,222	3,984,407
89	(561.5) Reliability, Planning and Standards Development	52	225
90	(561.6) Transmission Service Studies	-72,607	304,851
91	(561.7) Generation Interconnection Studies	-49,144	-41,842
92	(561.8) Reliability, Planning and Standards Development Services	3,285,498	2,920,968
93	(562) Station Expenses	1,963,348	1,286,083
94	(563) Overhead Lines Expenses	850,039	203,420
95	(564) Underground Lines Expenses		1,482
96	(565) Transmission of Electricity by Others	165,000,832	162,100,277
97	(566) Miscellaneous Transmission Expenses	2,838,661	2,293,951
98	(567) Rents	2,059,747	2,319,546
99	TOTAL Operation (Enter Total of lines 83 thru 98)	192,716,500	187,239,302
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	25,020	130,045
102	(569) Maintenance of Structures		
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	1,956,421	2,643,560
108	(571) Maintenance of Overhead Lines	946,050	1,508,830
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,927,491	4,282,435
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	195,643,991	191,521,737

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	169,027	182,903
116	(575.2) Day-Ahead and Real-Time Market Facilitation	311,254	167,117
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	19,911	1,092
120	(575.6) Market Monitoring and Compliance	35,401	18,356
121	(575.7) Market Facilitation, Monitoring and Compliance Services	8,300,814	7,968,818
122	(575.8) Rents	37,079	
123	Total Operation (Lines 115 thru 122)	8,873,486	8,338,286
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 Op Expns (Total 123 and 130)	8,873,486	8,338,286
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,556,619	2,947,090
135	(581) Load Dispatching	329,085	468,294
136	(582) Station Expenses	1,717,218	1,410,475
137	(583) Overhead Line Expenses	2,098,203	1,289,326
138	(584) Underground Line Expenses	-272,844	627,209
139	(585) Street Lighting and Signal System Expenses	211,147	809,945
140	(586) Meter Expenses	3,107,875	2,376,838
141	(587) Customer Installations Expenses	878,960	1,065,867
142	(588) Miscellaneous Expenses	15,844,820	9,924,375
143	(589) Rents	2,630,873	2,737,496
144	TOTAL Operation (Enter Total of lines 134 thru 143)	29,101,956	23,656,915
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	12,051	52,053
147	(591) Maintenance of Structures	6,274	
148	(592) Maintenance of Station Equipment	892,474	1,729,446
149	(593) Maintenance of Overhead Lines	7,455,870	10,082,150
150	(594) Maintenance of Underground Lines	586,215	293,387
151	(595) Maintenance of Line Transformers	-856	50,938
152	(596) Maintenance of Street Lighting and Signal Systems	670,964	164,231
153	(597) Maintenance of Meters	14,607	13,114
154	(598) Maintenance of Miscellaneous Distribution Plant		77,615
155	TOTAL Maintenance (Total of lines 146 thru 154)	9,637,599	12,462,934
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	38,739,555	36,119,849
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	19,140	28,047
160	(902) Meter Reading Expenses	4,693,900	4,357,488
161	(903) Customer Records and Collection Expenses	6,932,491	8,921,723
162	(904) Uncollectible Accounts	4,423,764	4,982,305
163	(905) Miscellaneous Customer Accounts Expenses	314,588	92,563
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	16,383,883	18,382,126

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	19,790,029	18,034,301
169	(909) Informational and Instructional Expenses	601,363	450,036
170	(910) Miscellaneous Customer Service and Informational Expenses	6,262	
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	20,397,654	18,484,337
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	233,108	127,744
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	233,108	127,744
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	30,544,808	33,197,091
182	(921) Office Supplies and Expenses	18,871,416	19,401,999
183	(Less) (922) Administrative Expenses Transferred-Credit	17,374,866	16,072,428
184	(923) Outside Services Employed	10,387,950	10,069,743
185	(924) Property Insurance	3,403,516	2,236,448
186	(925) Injuries and Damages	5,364,869	2,422,752
187	(926) Employee Pensions and Benefits	34,419,385	33,947,821
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	9,883,923	6,451,138
190	(929) (Less) Duplicate Charges-Cr.	1,405,511	1,272,819
191	(930.1) General Advertising Expenses	1,258,364	1,230,199
192	(930.2) Miscellaneous General Expenses	1,237,523	1,245,004
193	(931) Rents	12,812,192	12,598,042
194	TOTAL Operation (Enter Total of lines 181 thru 193)	109,403,569	105,454,990
195	Maintenance		
196	(935) Maintenance of General Plant	195,450	290,827
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	109,599,019	105,745,817
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,317,776,896	1,311,905,782

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 5 Column: b

FERC 501 - Fuel includes $1,446,310.21 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 5 Column: c

FERC 501 - Fuel includes $964,584 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 12 Column: b

The amount of $122,490 includes $124,830 of NOx purchases, $23,521 amortization of previously deferred NOx allowance cost and $5,133 amortization of previously deferred SO2 cost (authorized in NMPRC Case No. 17-00255), offset by deferral of New Mexico share of 2018 NOx purchase of ($30,994).

Schedule Page: 320 Line No.: 12 Column: c

The amount of $14,055 includes $16,575 of NOx purchases and $1,394 of amortization of previously deferred NOx allowance cost under the New Mexico jurisdiction (amortization authorized in Case No. 12-003550-UT), offset by New Mexico deferral of 2017 NOx purchase of ($3,914).

Schedule Page: 320 Line No.: 76 Column: b

FERC 555 - Purchased Power includes $42,670 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 76 Column: c

FERC 555 - Purchased Power includes $145,736 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 78 Column: b

The total of this account includes deferred expenses related to Fuel and Renewable Energy Costs as follows:

Fuel	$ 5,727,279
RECs and other renewable energy costs	$ 3,909,570

Schedule Page: 320 Line No.: 78 Column: c

The total of this account includes deferred expenses related to Fuel and Renewable Energy Certificates (RECs) as follows:

Fuel	$	1,646,294
RECs		1,413,843

Schedule Page: 320 Line No.: 90 Column: b

Credit balance results because Pension, Insurance and Taxes on Company labor billed for performing the studies is booked to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is booked to Account No. 561.6

Schedule Page: 320 Line No.: 91 Column: b

Generation Interconnection Study Revenues exceeded cost for the period.

Schedule Page: 320 Line No.: 91 Column: c

Generation Interconnection Study Revenues exceeded cost for the period.

Schedule Page: 320 Line No.: 138 Column: b

Unnatural balance due to timing of line transformer installations.

Schedule Page: 320 Line No.: 187 Column: b

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

Name of Respondent Southwestern Public Service Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

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	$36,656,442
Pension Tracker	$(1,469,509)
Amortization	$(767,548)
Pension and Benefit Expense as Reported	$34,419,385

Schedule Page: 320 Line No.: 187 Column: c

Texas PUC Docket No. 38147 authorized deferral of expense to Account No. 182.3
Docket No. 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

Pension and Benefit Expense	$	33,641,703
Pension Tracker		(102,418)
Amortization		408,536
Pension and Benefit Expense as Reported	$	33,947,821

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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)
1	Aeolus Wind, LLC	LU	QF			
2	Borger Energy Associates	LU	PSA	224		
3	Caprock Wind LP	LU	REPA			
4	Chaves County Solar, LLC	LU	SEPA			
5	Cirrus Wind I LLC	LU	QF			
6	De Wind Company	LU	QF			
7	Lea Power Partners	LU	PSA	604		
8	Lubbock Power & Light	LU	PSA	33		
9	Mammoth Plains Wind Project Holdings	LU	REPA			
10	Mesalands Community College LP	LU	QF			
11	National Windmill Project, Inc.	LU	QF			
12	Net Metering	OS	N/A			
13	Oneta Power LLC	LU	PSA	400		
14	Orion Engineered Carbons LLC	LU	PSA			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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)
1	Palo Duro Wind LLC	LU	REPA			
2	Pantex Wind	LU	QF			
3	Pleasant Hills Wind Energy	LU	QF			
4	Ralls Wind Farm LLC	LU	QF			
5	Roosevelt Wind Ranch LLC	LU	REPA			
6	Roswell Solar, LLC	LU	SEPA			
7	San Juan Mesa Wind Project LLC	LU	REPA			
8	Sid Richardson Carbon Ltd	LU	PSA	3		
9	Southwest Power Pool	OS	SPP			
10	Spinning Spur Wind LLC	LU	REPA			
11	Sun Edison Solar SPS LLC	LU	SEPA			
12	Sunray Wind LLC	LU	QF			
13	Suzlon Wind Project VIII, LLC	LU	QF			
14	Texico WInd LP	LU	REPA			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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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.

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)	Average Monthly CP Demand (f)
1	West Texas A&M University	LU	QF			
2	Wildorado Wind LP	LU	REPA			
3	Lorenzo Wind LLC	LU	REPA			
4	Wildcat Ranch Wind Project LLC	LU	REPA			
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,434				22,012		22,012	1
1,478,679			22,657,538	30,048,886		52,706,424	2
330,327				10,746,479		10,746,479	3
191,403				6,747,383	144,567	6,891,950	4
94,631				2,029,408	-20,922	2,008,486	5
					-666	-666	6
4,103,932			50,857,085	73,290,023		124,147,108	7
9,251			287,682	257,391		545,073	8
866,679				16,848,191	578,763	17,426,954	9
2,999				43,202	-462	42,740	10
373				7,567	-60	7,507	11
4,861				113,510		113,510	12
852,550			34,804,050	25,283,302		60,087,352	13
65,380				1,321,219		1,321,219	14
16,137,416			108,750,534	409,979,820	-39,484,031	479,246,323	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,181,425				25,155,252	1,201,009	26,356,261	1
14,672				137,228	-11,046	126,182	2
54,675				1,090,198	-16,555	1,073,643	3
25,890				515,289	-6,868	508,421	4
1,065,097				22,316,540	69,029	22,385,569	5
192,725				6,706,362	154,564	6,860,926	6
407,056				13,467,134		13,467,134	7
25,624			144,179	334,376		478,555	8
3,545,171				108,717,905	-41,875,020	66,842,885	9
717,468				27,574,888	222,426	27,797,314	10
97,381				12,106,415		12,106,415	11
				90	-91	-1	12
10,036				143,004	-2,162	140,842	13
2,792				170,946		170,946	14
16,137,416			108,750,534	409,979,820	-39,484,031	479,246,323	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,869				59,849	-723	59,126	1
665,715				22,874,151		22,874,151	2
79,775				1,089,930	62,308	1,152,238	3
46,546				761,690	17,878	779,568	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
16,137,416			108,750,534	409,979,820	-39,484,031	479,246,323	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 4 Column: l
Curtailment Adjustment

Schedule Page: 326 Line No.: 5 Column: l
SPP market charge pass through

Schedule Page: 326 Line No.: 6 Column: l
SPP market charge pass through

Schedule Page: 326 Line No.: 9 Column: l
Curtailment Adjustment

Schedule Page: 326 Line No.: 10 Column: l
SPP market charge pass through

Schedule Page: 326 Line No.: 11 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 1 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 2 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 3 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 4 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 5 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 6 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 9 Column: b
SPP market charges

Schedule Page: 326.1 Line No.: 9 Column: l
SPP market charges and ASM revenue

Regulation & Frequency Response Service	(8,256,857)
Spinning Reserve Service	(7,513,909)
Supplemental Reserve Service	(132,950)
	$ (15,903,715)

Schedule Page: 326.1 Line No.: 10 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 12 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 13 Column: l
SPP market charge pass through

Schedule Page: 326.2 Line No.: 1 Column: l
SPP market charge pass through

Schedule Page: 326.2 Line No.: 3 Column: l
Curtailment Adjustment

Schedule Page: 326.2 Line No.: 4 Column: l
Curtailment Adjustment

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

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 Classifi-cation (d)
1	Southwest Power Pool	N/A	N/A	
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				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY: MegaWatt Hours Received (i)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (j)	Line No.
SPP OATT	Various	Various		11,828,159	11,828,159	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
			0	**11,828,159**	**11,828,159**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
221,604,658		1,360,744	222,965,402	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
221,604,658	**0**	**1,360,744**	**222,965,402**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: d

LFP, SFP, FNO, FNS, OS

Schedule Page: 328 Line No.: 1 Column: m

Radial Line Facilities & Meter Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Tarirff (d)	Total Revenue (e)
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	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Southwest Power Pool				162,439,191	2,230,590	295,045	164,964,826
2	Public Service Co of CO	FNS			18,201			18,201
3	Swisher	OS					17,805	17,805
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				162,457,392	2,230,590	312,850	165,000,832

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: b

FNS, LFP, SFP, OS

Schedule Page: 332 Line No.: 1 Column: g

Other Charges for Southwest Power Pool (SPP) include the following:

Direct Assignment Charges (Meter Readings, Radial Facilities, Other)	$197,448
Direct Assigned Upgrade Charges per Z2 Tariff	$91,597
SPP Annual Membership Fee	$6,000
	295,045

Schedule Page: 332 Line No.: 2 Column: a

Southwestern Public Service Company and Public Service Company of Colorado are subsidiaries of Xcel Energy, Inc.

Schedule Page: 332 Line No.: 3 Column: g

Other Charges for Swisher include the following:

Wheeling Charge	$16,245
Annual Equipment Rental Fee	$1,560
	$17,805

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	94,418
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Service Company Allocation of Shareholder Meetings	148,001
7	Shareholder Meetings	212
8	Service Company Allocation of Director Fees and Exp	433,069
9	Service Company Allocation of SEC Filing Expense	14,507
10	Service Company Allocation of Industry Association s	547,316
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		
43		
44		
45		
46	TOTAL	1,237,523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

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 8 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 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			24,607,394		24,607,394
2	Steam Production Plant	44,049,830	-193,006	352,362		44,209,186
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,319,281	6,785			7,326,066
7	Transmission Plant	61,450,246	782	2,197,586		63,648,614
8	Distribution Plant	33,572,931	186,164	143,974	-198,142	33,704,927
9	Regional Transmission and Market Operation					
10	General Plant	22,057,833	1,218	297,925		22,356,976
11	Common Plant-Electric					
12	TOTAL	168,450,121	1,943	27,599,241	-198,142	195,853,163

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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	310	1,563					
14	310	311			1.76		14.85
15	310	10,217			3.11		25.62
16	311	135,377		-7.96	2.45		23.07
17	312	785,375		-4.47	2.24		22.62
18	314	342,818		-4.65	2.09		24.16
19	315	47,628		-4.27	1.89		23.44
20	316	18,410		-7.44	2.07		20.85
21	317	3,044					
22	Subtotal Steam Prod-Cl	1,344,743					
23							
24	Steam Production-Gas						
25	310	2,793					
26	310	787					
27	310	1,331					
28	310	73					
29	311	102,903					
30	312	209,744					
31	314	162,856					
32	315	34,131					
33	316	13,357					
34	317	-3,559					
35	Subtotal Steam Prod-G	524,416					
36							
37	Other Production						
38	340	161					
39	340	1					
40	341	14,344					
41	342	6,072					
42	343	54,836					
43	344	177,040					
44	345	31,695					
45	346	4,707					
46	347	136					
47	Subtotal Other Prod	288,992					
48							
49	Transmission						
50	350	8,488					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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	350	143,599					
13	352	90,965					
14	353	1,054,201					
15	354	8,211					
16	355	1,106,225					
17	356	419,340					
18	357	264					
19	359	490					
20	359	518					
21	359.1	25					
22	Subtotal Transmission	2,832,326					
23							
24	Distribution						
25	360	3,865					
26	360	9,256					
27	361	22,720					
28	362	276,634					
29	364	280,834					
30	365	268,829					
31	366	25,103					
32	367	43,848					
33	368	212,035					
34	369	45,892					
35	369	41,174					
36	370	66,994					
37	371	6,534					
38	373	28,146					
39	374	6,544					
40	Subtotal Distribution	1,338,408					
41							
42	General						
43	389	1,098					
44	389	46					
45	390	68,271					
46	390	4,054					
47	391	15,725					
48	391	66,091					
49	392	2,647					
50	392	41,407					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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	392	8,001					
13	392	56,141					
14	393	431					
15	394	40,293					
16	395	11,092					
17	396	14,799					
18	397	62,617					
19	397	23,827					
20	397	43					
21	397	25,420					
22	398	2,782					
23	399.1	64					
24	Subtotal General	444,849					
25							
26	TOTAL	6,773,734					
27							
28							
29							
30							
31							
32							
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 1 Column: d

The Amortization of Limited Term Electric Plant within Account 404 includes the following:

Software $24,607,394

Schedule Page: 336 Line No.: 7 Column: b

Transmission Serving Production $ 623,542

Schedule Page: 336 Line No.: 12 Column: f

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	$ -	$ 24,572,017	$ 24,572,017
2	Steam Production Plant	39,253,766	264,507	39,518,273
3	Nuclear Production Plant			-
4	Hydraulic Production Plant-Conventional			-
5	Hydraulic Production Plant-Pumped Storage			-
6	Other Production Plant	8,077,325	-	8,077,325
7	Transmssion Plant	52,827,501	2,909,258	55,736,759
8	Distribution Plant	33,572,931	143,974	33,716,905
9	Regional Transmission and Market Operation			-
10	General Plant	20,983,035	297,856	21,280,891
11	Common Plant-Electric			-
12	Total	$ 154,714,558	$ 28,187,612	$ 182,902,170

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.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2019	2018/Q4

FOOTNOTE DATA

Column (d) line 12: Computer software is being amortized over its expected useful life.

Transmission Serving Production $ 581,472

The Amortization of Limited Term Electric Plant within Account 404 includes the following:
Software $ 24,572,017

NOTE: Amounts footnoted are based upon FERC ONLY RATES.

Schedule Page: 336 Line No.: 13 Column: a
310 Land Owned in Fee
Schedule Page: 336 Line No.: 14 Column: a
310.002 Land Rights
Schedule Page: 336 Line No.: 15 Column: a
310.003 Production Water Rights
Schedule Page: 336 Line No.: 25 Column: a
310 Land Owned in Fee
Schedule Page: 336 Line No.: 26 Column: a
310.002 Land Rights
Schedule Page: 336 Line No.: 27 Column: a
310.003 Production Water Rights
Schedule Page: 336 Line No.: 28 Column: a
310.004 Production Land Rights
Schedule Page: 336 Line No.: 38 Column: a
340 Other Production - Land Owned in Fee
Schedule Page: 336 Line No.: 39 Column: a
340 Other Production - Land Rights
Schedule Page: 336 Line No.: 50 Column: a
350 Transmission - Land Owned in Fee
Schedule Page: 336.1 Line No.: 12 Column: a
350 Transmission - Land Rights
Schedule Page: 336.1 Line No.: 25 Column: a
360 Distribution - Land Owned in Fee
Schedule Page: 336.1 Line No.: 26 Column: a
360 Distribution - Land Rights
Schedule Page: 336.1 Line No.: 34 Column: a
369.1 Overhead Services
Schedule Page: 336.1 Line No.: 35 Column: a
369.2 Underground Services
Schedule Page: 336.1 Line No.: 43 Column: a
389 General - Land Owned in Fee
Schedule Page: 336.1 Line No.: 44 Column: a
389 General - Land Rights
Schedule Page: 336.1 Line No.: 45 Column: a
390 Structures and Improvements
Schedule Page: 336.1 Line No.: 46 Column: a
390.7 Remodeling Lease Facilities
Schedule Page: 336.1 Line No.: 47 Column: a
391 Office Furniture and Equipment
Schedule Page: 336.1 Line No.: 48 Column: a
391.4 Network Equipment

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 336.1 Line No.: 49 Column: a

392.1 Transportation Equipment - Automobiles

Schedule Page: 336.1 Line No.: 50 Column: a

392.2 Transportation Equipment - Light Trucks

Schedule Page: 336.2 Line No.: 12 Column: a

392.3 Transportation Equipment - Trailers

Schedule Page: 336.2 Line No.: 13 Column: a

392.4 Transportation Equipment - Heavy Trucks

Schedule Page: 336.2 Line No.: 17 Column: a

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	$ 7,008,181	$ 108,196,000
396 Power Operated Equipment	730,070	14,799,000
Total	$ 7,738,251	$ 122,995,000

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.

Schedule Page: 336.2 Line No.: 18 Column: a

397 Communication Equipment

Schedule Page: 336.2 Line No.: 19 Column: a

397.1 Communication Equipment - Two Way

Schedule Page: 336.2 Line No.: 20 Column: a

397.2 Communication Equipment - AES

Schedule Page: 336.2 Line No.: 21 Column: a

397.3 Communication Equipment - EMS

Schedule Page: 336.2 Line No.: 26 Column: b

(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):
Page 337-337.1 Changes to Steam Production-Coal have occurred since filing in the 2017 FERC Form 1, due to approved rates from the SPS PUC Texas Case 47527 that became effective 1/1/2018 related to Tolk Steam Production-Coal. No other changes to the underlying factors presented in columns (c) through (g) have occurred since filing the 2016 FERC Form 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Public Utilities Commission of Texas:				
2	Gross Receipts Assessment	1,468,564		1,468,564	
3	Docket Nos. 42004 & 44498 - 2014 TX RC		797,124	797,124	797,124
4	Docket No. 43695 & 46328 - 2015 TX RC		226,336	226,336	221,470
5	Docket No. 45524 & 46328 - 2016 TX RC		1,026,746	1,026,746	2,846,202
6	Docket No. 46025 & 47588 - 2016 TX Fuel Rec				625,712
7	Docket No. 46877 & 47588 - 2017 TX TCRF				180,009
8	Docket No. 47527 & 47588 - 2017 TX RC		907,857	907,857	1,080,028
9	Docket No. 48718 - Fuel Refund 1/16-5/18		41,618	41,618	
10	Docket No. 48847 - ITS Fuel Factor Formulas		79,349	79,349	
11	Doc 46901		51,085	51,085	
12	Miscellaneous items < $25k		45,355	45,355	
13					
14	New Mexico Public Regulation Commission				
15	Assessment Charges	2,083,103		2,083,103	
16					
17	Case Nos. 15-00139-UT & 15-00296-UT		545,857	545,857	545,857
18	2015 NM Retail Rate & Supreme Court Case				
19	Case No. 16-00269-UT - 2016 NM RC		1,074,671	1,074,671	1,076,136
20	Case No. 17-00255-UT - 2017 NM RC		373,177	373,177	468,993
21	Case No. S-1-SC-36466 - 2017 NM SCC		56,694	56,694	724
22	Case No. 18-00201 - 2018 Ren Portfolio		222,911	222,911	
23	Case No. 18-00215 - 2018 Integrated		31,594	31,594	
24	Resource Plan For NM				
25	Case No. 18-00308 - Solar*Connect		78,660	78,660	
26	Case No. 18-00329 - Plant X &		92,022	92,022	
27	Cunningham Retire				
28	Miscellaneous items < $25k		92,853	92,853	
29					
30	Federal Energy Regulatory Commission:				
31	ER18-228		202,017	202,017	
32	2018 Prod Depr Formula Change				
33	ER19-404		82,200	82,200	
34	Annual Transmission Revenue Requirement				
35	ER19-675		164,230	164,230	
36	2019 FERC Trans Depr Rate Change				
37	ER18-675		31,000	31,000	
38	2019 FERC Distribution Delivery Rate				
39	Miscellaneous items < $25k		14,629	14,629	
40					
41	OTHER				
42	Mandated Regulatory Notices		91,624	91,624	
43	Miscellaneous Items < $25,000		2,647	2,647	
44					
45					
46	TOTAL	3,551,667	6,332,256	9,883,923	7,842,255

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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 column (f), (g), and (h) expenses incurred during 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							
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)	Line No.
							1
Electric	928	1,468,564					2
Electric	928	797,124		186	797,124		3
Electric	928	226,336	55,152	186	276,622		4
Electric	928	1,026,746	-417,081	186	1,026,747	1,402,374	5
			-13	186		625,699	6
			-199	186		179,810	7
Electric	928	907,857	1,277,829	186	907,857	1,450,000	8
Electric	928	41,618					9
Electric	928	79,349					10
Electric	928	51,085					11
Electric	928	45,355					12
							13
							14
Electric	928	2,083,103					15
							16
Electric	928	545,857		186	545,857		17
							18
Electric	928	1,074,671	-1,465	186	1,074,671		19
Electric	928	373,177	1,055,081	186	373,177	1,150,897	20
Electric	928	56,694	56,421	186	56,694	451	21
Electric	928	222,911					22
Electric	928	31,594					23
							24
Electric	928	78,660					25
Electric	928	92,022					26
							27
Electric	928	92,853					28
							29
							30
Electric	928	202,017					31
							32
Electric	928	82,200					33
							34
Electric	928	164,230					35
							36
Electric	928	31,000					37
							38
Electric	928	14,629					39
							40
							41
Electric	928	91,624					42
Electric	928	2,647					43
							44
							45
		9,883,923	2,025,725		5,058,749	4,809,231	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 & 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 & 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:
A. Electric R, D & D Performed Internally:
 (1) Generation
  a. hydroelectric
   i. Recreation fish and wildlife
   ii Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) Transmission
  a. Overhead
  b. Underground
 (3) Distribution
 (4) Regional Transmission and Market Operation
 (5) Environment (other than equipment)
 (6) Other (Classify and include items in excess of $50,000.)
 (7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B(1)	Electric Power Research Institute
2		
3	B(2)	Edision Electric Institute
4		
5	B(5)	Total
6		
7		
8		
9		
10		
11		
12		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred
3. Include in column (c) all R, D & 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 & 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 & 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 &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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
	247,785	Various	247,785		1
					2
	332,967	Various	332,967		3
					4
	580,752		580,752		5
					6
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					8
					9
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 352 Line No.: 1 Column: e

Accounts charged:

107	$52,641
506	300
921	18,806
923	2,877
930.2	173,161
	$247,785

Schedule Page: 352 Line No.: 3 Column: e

Accounts charged:

426.1	$7,470
426.4	41,587
921	9,350
930.2	274,560
	$332,967

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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	27,364,512		
4	Transmission	12,490,280		
5	Regional Market	520,837		
6	Distribution	14,676,945		
7	Customer Accounts	6,551,245		
8	Customer Service and Informational	1,902,253		
9	Sales	225,503		
10	Administrative and General	30,527,565		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	94,259,140		
12	Maintenance			
13	Production	21,105,400		
14	Transmission	973,117		
15	Regional Market			
16	Distribution	5,508,888		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	27,587,405		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	48,469,912		
21	Transmission (Enter Total of lines 4 and 14)	13,463,397		
22	Regional Market (Enter Total of Lines 5 and 15)	520,837		
23	Distribution (Enter Total of lines 6 and 16)	20,185,833		
24	Customer Accounts (Transcribe from line 7)	6,551,245		
25	Customer Service and Informational (Transcribe from line 8)	1,902,253		
26	Sales (Transcribe from line 9)	225,503		
27	Administrative and General (Enter Total of lines 10 and 17)	30,527,565		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	121,846,545	2,264,504	124,111,049
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			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
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)	121,846,545	2,264,504	124,111,049
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	34,404,347	18,840,994	53,245,341
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	34,404,347	18,840,994	53,245,341
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,555,932	1,947,350	5,503,282
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,555,932	1,947,350	5,503,282
77	Other Accounts (Specify, provide details in footnote):			
78	Regulatory Assets (Account No. 182.3)	760,664	9,682	770,346
79	Preliminary Survey and Investigation (Account No. 183)		-84,025	-84,025
80	Misc Deferred Debits (Account No. 186)	2,918	-11,839	-8,921
81	Nonutility (Account Nos. 416-417.1)	24,892	98	24,990
82	Misc Income and Deductions (Account Nos. 426.1-5)	108,288	2,138	110,426
83	Nonutility CWP and RWP	-1,924		-1,924
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	894,838	-83,946	810,892
96	TOTAL SALARIES AND WAGES	160,701,662	22,968,902	183,670,564

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 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 order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
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43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) 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)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			4,799,281			1,164,200
2	Reactive Supply and Voltage			119,838			140,049
3	Regulation and Frequency Response			3,667,325			8,411,784
4	Energy Imbalance						
5	Operating Reserve - Spinning			3,339,036			7,513,909
6	Operating Reserve - Supplement			581,987			132,950
7	Other						
8	Total (Lines 1 thru 7)			12,507,467			17,362,892

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 1 Column: b

Volume is not available for lines 1 through 7.

Schedule Page: 398 Line No.: 1 Column: c

Volume is not available for lines 1 through 7.

Schedule Page: 398 Line No.: 1 Column: d

Sch 1 Charges	780,059
SPP Administrative Fees - SSC&D	4,019,222
Total 'Scheduling, System Control & Dispatch'	4,799,281

Schedule Page: 398 Line No.: 1 Column: e

Volume is not available for lines 1 through 7.

Schedule Page: 398 Line No.: 1 Column: f

Volume is not available for lines 1 through 7.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

NAME OF SYSTEM:

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)
1	January	4,394	17	800	2,963	1,431				
2	February	4,075	5	800	2,714	1,361				
3	March	3,911	2	800	2,555	1,356				
4	Total for Quarter 1				8,232	4,148				
5	April	4,327	12	1800	2,687	1,640				
6	May	5,552	31	1800	3,340	2,212				
7	June	5,752	27	1800	3,457	2,295				
8	Total for Quarter 2				9,484	6,147				
9	July	6,159	19	1700	3,604	2,555				
10	August	5,784	7	1800	3,386	2,398				
11	September	5,009	1	1500	3,073	1,936				
12	Total for Quarter 3				10,063	6,889				
13	October	4,565	3	1700	3,027	1,538				
14	November	4,231	12	1900	2,860	1,371				
15	December	4,303	14	800	2,934	1,369				
16	Total for Quarter 4				8,821	4,278				
17	Total Year to Date/Year				36,600	21,462				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports 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)
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 Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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)	20,450,500
3	Steam	13,464,632	23	Requirements Sales for Resale (See instruction 4, page 311.)	5,113,339
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,963,701
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	17,553
7	Other	1,490,787	27	Total Energy Losses	547,742
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	31,092,835
9	Net Generation (Enter Total of lines 3 through 8)	14,955,419			
10	Purchases	16,137,416			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	11,828,159			
17	Delivered	11,828,159			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	31,092,835			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK: Megawatts (See Instr. 4) (d)	MONTHLY PEAK: Day of Month (e)	MONTHLY PEAK: Hour (f)
29	January	2,502,372	330,184	3,705	17	8
30	February	2,106,107	218,399	3,443	12	8
31	March	2,180,203	373,523	3,187	7	8
32	April	2,668,614	402,054	3,394	12	18
33	May	2,675,245	533,456	4,344	31	18
34	June	2,829,417	517,068	4,447	27	18
35	July	3,314,505	736,038	4,648	19	17
36	August	2,918,148	417,104	4,391	28	17
37	September	2,546,103	363,736	3,950	1	15
38	October	2,302,908	349,631	3,863	3	17
39	November	2,378,007	422,049	3,571	12	19
40	December	2,671,206	300,459	3,650	28	19
41	TOTAL	31,092,835	4,963,701			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	Plant Name: *Jones Gas* (b)			Plant Name: *Maddox Gas* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed	2011			1976		
4	Year Last Unit was Installed	2013			1983		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	365.40			98.35		
6	Net Peak Demand on Plant - MW (60 minutes)	397			71		
7	Plant Hours Connected to Load	2775			3204		
8	Net Continuous Plant Capability (Megawatts)	366			63		
9	When Not Limited by Condenser Water	366			63		
10	When Limited by Condenser Water	334			61		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	718099000			197102000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	11253702			1643938		
15	Equipment Costs	155631656			17739124		
16	Asset Retirement Costs	0			0		
17	Total Cost	166885358			19383062		
18	Cost per KW of Installed Capacity (line 17/5) Including	456.7196			197.0825		
19	Production Expenses: Oper, Supv, & Engr	7158			6333		
20	Fuel	20949354			5114189		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	150461			293845		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	170701			91186		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	49128			2		
30	Maintenance of Structures	127820			14267		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	269177			461803		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	21723799			5981625		
35	Expenses per Net KWh	0.0303			0.0303		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf			Mcf		
38	Quantity (Units) of Fuel Burned	8549839	0	0	2343914	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1048	0	0	1025	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.450	0.000	0.000	2.180	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.460	0.000	0.000	2.190	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.340	0.000	0.000	2.130	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.030	0.000	0.000	0.030	0.000	0.000
44	Average BTU per KWh Net Generation	12478686.0	0.000	0.000	12193.996	0.000	0.000

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Jones Station* (b)	Plant Name: *Moore County* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Outside Boiler
3	Year Originally Constructed	1971	1938
4	Year Last Unit was Installed	1974	1954
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	495.00	49.00
6	Net Peak Demand on Plant - MW (60 minutes)	487	0
7	Plant Hours Connected to Load	7884	0
8	Net Continuous Plant Capability (Megawatts)	486	46
9	When Not Limited by Condenser Water	486	46
10	When Limited by Condenser Water	486	46
11	Average Number of Employees	29	0
12	Net Generation, Exclusive of Plant Use - KWh	1682886000	0
13	Cost of Plant: Land and Land Rights	2274925	0
14	Structures and Improvements	16319594	0
15	Equipment Costs	116319291	0
16	Asset Retirement Costs	-1620300	0
17	Total Cost	133293510	0
18	Cost per KW of Installed Capacity (line 17/5) Including	269.2798	0.0000
19	Production Expenses: Oper, Supv, & Engr	478533	0
20	Fuel	35577908	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	1433626	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1822480	0
26	Misc Steam (or Nuclear) Power Expenses	1624993	0
27	Rents	712303	0
28	Allowances	15309	0
29	Maintenance Supervision and Engineering	258938	0
30	Maintenance of Structures	900648	0
31	Maintenance of Boiler (or reactor) Plant	757261	0
32	Maintenance of Electric Plant	616888	0
33	Maintenance of Misc Steam (or Nuclear) Plant	580193	0
34	Total Production Expenses	44779080	0
35	Expenses per Net KWh	0.0266	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil	Composite			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	Bbls				
38	Quantity (Units) of Fuel Burned	15913938	6763	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1029	135820	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.190	83.560	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.200	83.560	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.140	14.770	2.170	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.020	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	9751.074	0.000	0.000	0.000

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Cunningham Steam* (b)			Plant Name: *Maddox Steam* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outside Boiler			Outside Boiler		
3	Year Originally Constructed	1957			1967		
4	Year Last Unit was Installed	1965			1983		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	265.40			113.64		
6	Net Peak Demand on Plant - MW (60 minutes)	255			115		
7	Plant Hours Connected to Load	7549			5769		
8	Net Continuous Plant Capability (Megawatts)	251			112		
9	When Not Limited by Condenser Water	251			112		
10	When Limited by Condenser Water	251			112		
11	Average Number of Employees	46			0		
12	Net Generation, Exclusive of Plant Use - KWh	792484500			362332000		
13	Cost of Plant: Land and Land Rights	61235			25990		
14	Structures and Improvements	12439078			4909575		
15	Equipment Costs	59687043			40676690		
16	Asset Retirement Costs	118564			-671128		
17	Total Cost	72305920			44941127		
18	Cost per KW of Installed Capacity (line 17/5) Including	272.4413			395.4693		
19	Production Expenses: Oper, Supv, & Engr	64232			29761		
20	Fuel	18470000			8965263		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1405682			496372		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	472524			250750		
26	Misc Steam (or Nuclear) Power Expenses	865640			531957		
27	Rents	569756			338987		
28	Allowances	7209			3296		
29	Maintenance Supervision and Engineering	77999			2879		
30	Maintenance of Structures	178550			212115		
31	Maintenance of Boiler (or reactor) Plant	1918546			535088		
32	Maintenance of Electric Plant	1117667			216047		
33	Maintenance of Misc Steam (or Nuclear) Plant	350348			797133		
34	Total Production Expenses	25498153			12379648		
35	Expenses per Net KWh	0.0322			0.0342		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf			Mcf		
38	Quantity (Units) of Fuel Burned	8216124	0	0	3850792	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1028	0	0	1042	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.240	0.000	0.000	2.320	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.250	0.000	0.000	2.330	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.190	0.000	0.000	2.230	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.000	0.020	0.000	0.000
44	Average BTU per KWh Net Generation	10656.909	0.000	0.000	11071.352	0.000	0.000

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Cunningham Gas Turbs* (d)			Plant Name: *Plant X* (e)			Plant Name: *Tolk Station* (f)			Line No.
Gas Turbine			Steam			Steam			1
			Outside Boiler			Outside Boiler			2
1998			1952			1982			3
1998			1964			1985			4
253.80			434.40			1135.80			5
215			413			1046			6
4392			7894			8581			7
209			411			1067			8
209			411			1067			9
196			411			1067			10
0			0			96			11
575417000			1221177000			3810060000			12
0			1752767			10862393			13
588074			13296142			88135700			14
71902268			96577439			671779896			15
0			-1930863			2702781			16
72490342			109695485			773480770			17
285.6199			252.5218			681.0009			18
18604			236298			513790			19
14489297			29990559			90968996			20
0			0			0			21
0			671077			2325314			22
0			0			0			23
0			0			0			24
124675			848961			1845437			25
0			1370450			3298201			26
221385			658012			1532604			27
0			11109			34661			28
165202			104156			464363			29
254411			629921			2107246			30
0			1440623			4760777			31
675588			1076876			4595982			32
0			1182083			3477566			33
15949162			38220125			115924937			34
0.0277			0.0313			0.0304			35
Gas			Gas	Oil	Composite	Coal	Gas	Composite	36
Mcf			Mcf	Bbls		Tons	Mcf		37
6517557	0	0	13677773	-54	0	2234690	309990	0	38
1034	0	0	1030	0	0	8969	1025	0	39
2.220	0.000	0.000	2.190	-34.740	0.000	40.190	2.690	0.000	40
2.230	0.000	0.000	2.190	-34.740	0.000	40.320	2.690	0.000	41
2.160	0.000	0.000	2.130	10.090	2.130	2.270	2.620	2.270	42
0.030	0.000	0.000	0.000	0.000	0.020	0.000	0.000	0.020	43
11707.960	0.000	0.000	0.000	0.000	11541.267	0.000	0.000	10507.970	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Nichols Station* (d)			Plant Name: *Harrington Station* (e)			Plant Name: *Carlsbad Gas* (f)			Line No.
		Steam			Steam			Gas Turbine	1
		Conventional			Outside Boiler				2
		1960			1976			1977	3
		1968			1980			1977	4
		474.77			1080.00			16.32	5
		460			1019			0	6
		6933			8760			0	7
		457			1018			13	8
		457			1018			13	9
		457			1018			10	10
		0			131			0	11
		869805850			4725886000			0	12
		818610			1231654			0	13
		56816573			48788576			0	14
		109870978			532123584			0	15
		-1481552			1768281			0	16
		166024609			583912095			0	17
		349.6948			540.6593			0.0000	18
		92471			874980			0	19
		26586498			92722544			46	20
		0			0			0	21
		357467			4204622			0	22
		0			0			0	23
		0			0			0	24
		2378175			2585087			0	25
		1416534			4258100			0	26
		722546			2021883			0	27
		7913			42992			0	28
		190222			321377			0	29
		519961			921282			0	30
		988483			5802132			0	31
		919430			1859161			0	32
		945402			3749829			0	33
		35125102			119363989			46	34
		0.0404			0.0253			0.0000	35
Gas			Coal	Gas	Composite	Gas			36
Mcf			Tons	Mcf		Mcf			37
9893988	0	0	2827354	310360	0	0	0	0	38
1036	0	0	8965	1023	0	1036	0	0	39
2.680	0.000	0.000	32.390	2.440	0.000	0.000	0.000	0.000	40
2.690	0.000	0.000	32.510	2.440	0.000	0.000	0.000	0.000	41
2.590	0.000	0.000	1.830	2.380	1.840	0.000	0.000	0.000	42
0.030	0.000	0.000	0.000	0.000	0.020	0.000	0.000	0.000	43
11778.809	0.000	0.000	0.000	0.000	10670.859	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Quay County* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Gas Turbine			1
			2
2013			3
2013			4
27.00	0.00	0.00	5
21	0	0	6
15	0	0	7
23	0	0	8
23	0	0	9
17	0	0	10
0	0	0	11
169130	0	0	12
103888	0	0	13
916182	0	0	14
25485057	0	0	15
0	0	0	16
26505127	0	0	17
981.6714	0	0	18
5	0	0	19
56653	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
6092	0	0	25
36502	0	0	26
14957	0	0	27
0	0	0	28
0	0	0	29
9347	0	0	30
0	0	0	31
130633	0	0	32
0	0	0	33
254189	0	0	34
1.5029	0.0000	0.0000	35

									Line No.
Oil									36
Bbls									37
751	0	0	0	0	0	0	0	0	38
136236	0	0	0	0	0	0	0	0	39
75.390	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
75.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
18.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.340	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
18062.159	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
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)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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 the 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."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
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)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
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	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
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)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
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			11
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			22
			23
			24
			25
			26
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			31
			32
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			34
			35
			36
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 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.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	(J26-KS;01) CARPENTER	HITCHLAND	345.00	345.00	H-FRAME	12.09		1
2	(J26-OK;01) CARPENTER	HITCHLAND	345.00	345.00	H-FRAME	38.14		1
3	(J26-TX;01) CARPENTER	HITCHLAND	345.00	345.00	H-FRAME	0.47		1
4	(J25;01) CARPENTER	FINNEY SW STA	345.00	345.00	H-FRAME	67.29		1
5	(J23;01) KIOWA	ROADRUNNER	345.00	345.00	H-FRAME	40.30		1
6	(J22;01) CHINA DRAW	NORTH LOVING	345.00	345.00	H-FRAME	18.11		1
7	(J21;01) KIOWA	NORTH LOVING	345.00	345.00	H-FRAME	21.89		1
8	(J20;01) HOBBS	KIOWA	345.00	345.00	H-FRAME	47.19		1
9			345.00	345.00	SINGLE POLE	0.67		1
10	(J15-NM;01) CROSSROADS	TOLK STA	345.00	345.00	H-FRAME	20.04		1
11	(J15-TX;01) CROSSROADS	TOLK STA	345.00	345.00	H-FRAME	31.79		1
12	(J14;01) CROSSROADS	EDDY CO INTG	345.00	345.00	H-FRAME	106.05		1
13	(J13-OK;02) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE		29.03	1
14	(J13-TX;02) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE		0.28	1
15	(J12-OK;01) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE	29.03		1
16	(J12-TX;01) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE	0.28		1
17	(J11-OK;01) BORDER	TUCO	345.00	345.00	H-FRAME	2.08		1
18			345.00	345.00	SINGLE POLE	4.14		1
19	(J11-TX;01) BORDER	TUCO	345.00	345.00	3 POLE	0.87		1
20			345.00	345.00	SINGLE POLE	0.52		1
21			345.00	345.00	H-FRAME	21.73		1
22			345.00	345.00	SINGLE POLE	172.02		1
23			345.00	345.00	SINGLE POLE	0.01		1
24	(J06;01) HITCHLAND	POTTER CO SW STA	345.00	345.00	H-FRAME	102.59		1
25	(J05-KS;01) FINNEY SW STA	LAMAR 345KV SW STA	345.00	345.00	H-FRAME	78.76		1
26	(J04;01) FINNEY SW STA	HOLCOMB POWER PLANT	345.00	345.00	H-FRAME	0.75		1
27	(J01;01) OKLAUNION /	TUCO	345.00	345.00	H-FRAME	160.50		1
28	(R06;01) NEEDMORE	YOAKUM CO INTG	230.00	230.00	H-FRAME	13.72		1
29			230.00	230.00	K-FRAME	59.42		1
30			230.00	230.00	SPECIAL	1.12		1
31	(R05;01) NEEDMORE	TOLK STA	230.00	230.00	K-FRAME	13.60	0.06	1
32	(R04-NM;01) ANDREWS CO.	HOBBS GENERATING	230.00	345.00	H-FRAME	0.47		1
33			230.00	345.00	H-FRAME	22.73		1
34	(R04-TX;01) ANDREWS CO.	HOBBS GENERATING	230.00	345.00	H-FRAME	7.69		1
35	(K99;01) CARLISLE	WOLFFORTH INTG	230.00	230.00	SINGLE POLE	13.04		1
36					TOTAL	7,101.62	613.50	127

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(K98;01) CHANNING	XIT	230.00	230.00	SINGLE POLE	32.37		1
2	(K97;01) CHANNING	POTTER CO SW STA	230.00	230.00	SINGLE POLE	41.79		1
3	(K94;01) CIRRUS	GRASSLAND INTG	230.00	345.00	SINGLE POLE	10.09		1
4	(K93-NM;01) HOBBS	YOAKUM CO INTG	230.00	230.00	H-FRAME	23.11		1
5	(K93-TX;01) HOBBS	YOAKUM CO INTG	230.00	230.00	H-FRAME	24.72		1
6	(K92;01) CUNNINGHAM	HOBBS GENERATING	230.00	230.00	H-FRAME	3.02		1
7	(K91;01) NEWHART	PLANT X	230.00	230.00	H-FRAME		1.27	1
8			230.00	230.00	SINGLE POLE	38.50		1
9	(K90;01) NEWHART	POTTER CO SW STA	230.00	230.00	H-FRAME	67.64		1
10	(K88;1) NEWHART	SWISHER CO INTG	230.00	230.00	SINGLE POLE	21.31		1
11	(K87;01) AMARILLO SOUTH	RANDALL CO	230.00	230.00	SINGLE POLE	8.37		1
12	(K86;01) HARRINGTON STA	ROLLING HILLS	230.00	230.00	H-FRAME	5.33	0.13	1
13	(K85;01) POTTER CO SW	ROLLING HILLS	230.00	230.00	H-FRAME	4.80		1
14			230.00	230.00	SINGLE POLE	1.20		1
15	(K84;01) PLEASANT HILL	ROOSEVELT CO INTG	230.00	230.00	SINGLE POLE	19.54		1
16	(K83;01) OASIS	PLEASANT HILL	230.00	230.00	H-FRAME	7.20		1
17			230.00	230.00	SINGLE POLE	21.35		1
18	(K82;01) BRU	OXY BENNETT RANCH	230.00	230.00	3 POLE	0.10		1
19	(K79-TX;01) BRU	YOAKUM CO INTG	230.00	230.00	H-FRAME	1.88		1
20			230.00	230.00	K-FRAME	3.47		1
21	(K78;01) AMOCO WASSON	BRU	230.00	230.00	K-FRAME	6.51		1
22	(K76;01) HITCHLAND	OCHILTREE SUB	230.00	230.00	SINGLE POLE	38.14		1
23	(K75;01) HITCHLAND	MOORE CO	230.00	230.00	H-FRAME	62.10	0.60	1
24	(K74-OK;01) SWEETWATER	WHEELER CO.	230.00	230.00	H-FRAME	0.24		1
25	(K74-TX;01) SWEETWATER	WHEELER CO.	230.00	230.00	H-FRAME	13.96		1
26	(K73;01) GRAPEVINE INTG	WHEELER CO.	230.00	230.00	H-FRAME	36.87		1
27	(K69;01) MUSTANG INTG	SEMINOLE INTG	230.00	230.00	SINGLE POLE	18.07		1
28	(K68;01) PECOS	SEVEN RIVERS	230.00	230.00	H-FRAME	18.87		1
29			230.00	230.00	SINGLE POLE	1.81		1
30	(K67;01) PECOS	POTASH JUNCTION	230.00	230.00	H-FRAME	14.64		1
31	(K66;01) CHAVES CO	SAN JUAN MESA	230.00	230.00	H-FRAME	0.57		1
32			230.00	230.00	SINGLE POLE	51.16		1
33	(K65;01) OASIS	SAN JUAN MESA	230.00	230.00	H-FRAME	46.62		1
34	(K63;01) AMARILLO SOUTH	SWISHER CO INTG	230.00	230.00	H-FRAME	49.24		1
35			230.00	230.00	K-FRAME		5.64	1
36					TOTAL	7,101.62	613.50	127

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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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1			230.00	230.00	SINGLE POLE	0.99		1
2	(K62;01) AMARILLO SOUTH	NICHOLS STA	230.00	230.00	K-FRAME	9.25	10.37	1
3	(K60;01) EDDY CO INTG	SEVEN RIVERS	230.00	230.00	H-FRAME	24.34		1
4	(K59;01) BUSHLAND	POTTER CO SW STA	230.00	230.00	H-FRAME	0.95		1
5			230.00	230.00	K-FRAME	15.06	0.23	1
6			230.00	230.00	SINGLE POLE		1.20	1
7	(K56;01) MUSTANG INTG	YOAKUM CO INTG	230.00	230.00	H-FRAME	12.82	0.15	1
8			230.00	230.00	SINGLE POLE	0.90		1
9	(K55;01) AMOCO WASSON	MUSTANG INTG	230.00	230.00	H-FRAME	3.53		1
10	(K53;01) GRAPEVINE INTG	NICHOLS STA	230.00	230.00	K-FRAME	52.76		1
11	(K52;01) CUNNINGHAM	POTASH JUNCTION	230.00	230.00	H-FRAME	39.86		1
12	(K51;01) OASIS	ROOSEVELT CO INTG	230.00	230.00	H-FRAME	2.56		1
13			230.00	230.00	K-FRAME	7.12		1
14	(K47;01) GRASSLAND INTG	JONES PLANT	230.00	345.00	K-FRAME	26.72		1
15	(K46;01) PLANT X	SUNDOWN SW. STA.	230.00	230.00	H-FRAME		3.22	1
16			230.00	230.00	K-FRAME	45.03		1
17	(K45;02) PLANT X	TOLK STA	230.00	230.00	K-FRAME	10.11		1
18	(K44;01) EAST PLANT	HARRINGTON STA	230.00	230.00	SINGLE POLE	6.95	0.11	1
19	(K43;01) HARRINGTON STA	PRINGLE	230.00	230.00	K-FRAME	58.94	0.25	1
20	(K42;01) TOLK STA	TUCO	230.00	230.00	H-FRAME	4.34		1
21			230.00	230.00	K-FRAME	50.02		1
22	(K39;01) CARLISLE	MCDONALD (LP&L)	230.00	230.00	2 POLE	0.18		1
23	(K38;01) CHAVES CO	EDDY CO INTG	230.00	230.00	H-FRAME	2.16		1
24			230.00	230.00	K-FRAME	50.44		1
25	(K37;01) LAMB CO INTG	TOLK STA	230.00	230.00	K-FRAME	35.09		1
26	(K34;01) AMOCO	AMOCO SW. STA.	230.00	230.00	Unknown	0.03		1
27	(K33;01) AMOCO SW. STA.	YOAKUM CO INTG	230.00	230.00	H-FRAME	36.96		1
28	(K32;01) HARRINGTON STA	POTTER CO SW STA	230.00	230.00	K-FRAME	11.08	0.13	1
29	(K31;01) MOORE CO	POTTER CO SW STA	230.00	230.00	K-FRAME	47.90		1
30	(K30-NM;02) ROOSEVELT	TOLK STA	230.00	230.00	K-FRAME	9.59		1
31	(K30-TX;02) ROOSEVELT CO	TOLK STA	230.00	230.00	H-FRAME	8.78		1
32			230.00	230.00	K-FRAME	21.63		1
33	(K27;01) PLANT X	TOLK STA	230.00	230.00	K-FRAME	9.64		1
34	(K24;01) CARLISLE	TUCO	230.00	230.00	H-FRAME	1.55		1
35			230.00	230.00	K-FRAME	25.60		1
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(K23;01) CUNNINGHAM	EDDY CO INTG	230.00	230.00	K-FRAME	58.81		1
2	(K21;01) DEAF SMITH	PLANT X	230.00	230.00	H-FRAME	2.64		1
3			230.00	230.00	K-FRAME	44.23		1
4	(K19;01) HARRINGTON STA	RANDALL CO	230.00	230.00	K-FRAME	10.17	0.13	1
5			230.00	230.00	Unknown	1.34		1
6	(K18-NM;01) ROOSEVELT	TOLK STA	230.00	230.00	K-FRAME	11.23		1
7	(K18-TX;01) ROOSEVELT CO	TOLK STA	230.00	230.00	K-FRAME	28.02	0.04	1
8	(K17;02) HARRINGTON STA	NICHOLS STA	230.00	230.00	K-FRAME	0.95	0.13	1
9	(K16;01) HARRINGTON STA	NICHOLS STA	230.00	230.00	H-FRAME	1.06		1
10	(K15;01) JONES PLANT	LUBBOCK EAST	230.00	230.00	TOWER	2.55	3.72	1
11	(K14;02) JONES PLANT	LUBBOCK SOUTH	230.00	230.00	TOWER	0.16	5.28	1
12	(K11;01) BUSHLAND	DEAF SMITH INTERCHANGE	230.00	230.00	SINGLE POLE	33.52		1
13	(K10;01) LUBBOCK SOUTH	WOLFFORTH INTG	230.00	230.00	H-FRAME	14.78		1
14	(K08;01) JONES PLANT	LUBBOCK SOUTH	230.00	230.00	TOWER	5.39		1
15	(K07;01) JONES PLANT	TUCO	230.00	230.00	H-FRAME	20.89		1
16			230.00	230.00	TOWER	8.76		1
17	(K06;01) HUTCHINSON CO	SUNDOWN SW. STA.	230.00	230.00	H-FRAME	1.30		1
18			230.00	230.00	K-FRAME	29.15		1
19	(K03;01) AMOCO SW. STA.	SUNDOWN SW. STA.	230.00	230.00	K-FRAME	5.31		1
20	(K02;01) SUNDOWN SW.	WOLFFORTH INTG	230.00	230.00	H-FRAME	8.09		1
21			230.00	230.00	K-FRAME	16.49		1
22	(K01;01) SWISHER CO INTG	TUCO	230.00	230.00	K-FRAME	39.57		1
23								
24	SUMMARY OF 115 KV		115.00	345.00	Overhead	0.19		
25			115.00	230.00	Overhead	4.05		
26			115.00	115.00	Overhead	3,087.05	247.12	
27	SUMMARY OF 69 KV		69.00	69.00	Overhead	1,186.44	300.13	
28			69.00	115.00	Overhead	38.17	4.28	
29			69.00	69.00	Underground	4.74		
30								
31								
32								
33								
34								
35								
36					TOTAL	7,101.62	613.50	127

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
6-795 ACSR		746,643	746,643					1
6-795 ACSR	871,770	3,919,636	4,791,406					2
6-795 ACSR								3
6-795 ACSR	1,157,018	6,964,929	8,121,947					4
6-795 ACSR	852,435	45,032,541	45,884,976					5
6-795 ACSS	2,240,588	18,575,530	20,816,118					6
6-795 ACSS	1,485,856	22,503,068	23,988,924					7
6-795 ACSS	11,543,660	38,481,955	50,025,615					8
6-795 ACSS								9
6-795 ACSR	241,431	2,424,802	2,666,233					10
6-795 ACSR	445,174	4,249,391	4,694,565					11
6-795 ACSR	1,368,108	15,317,874	16,685,982					12
6-1590 ACSR	54,107	6,964,051	7,018,158					13
6-1590 ACSR		150,186	150,186					14
6-1590 ACSR	1,859,566	40,145,041	42,004,606					15
6-1590 ACSR	34,262	1,743,136	1,777,398					16
6-795 ACSS	259,826	4,718,648	4,978,474					17
6-795 ACSS								18
6-795 ACSS	22,509,754	171,136,448	193,646,202					19
6-795 ACSS								20
6-795 ACSS								21
6-795 ACSS								22
6-795 ACSS								23
6-795 ACSR	4,624,961	35,742,291	40,367,252					24
6-795 ACSR	3,941,720	42,882,621	46,824,341					25
6-795 ACSR		2,428,690	2,428,690					26
6-795 ACSR	2,428,536	25,893,053	28,321,589					27
3-795 ACSR	334,131	10,209,219	10,543,350					28
3-795 ACSR								29
3-795 ACSR								30
3-795 ACSR	61,477	2,446,432	2,507,910					31
3-795 ACSR	1,287,269	5,654,409	6,941,678					32
6-795 ACSR								33
6-795 ACSR	23,704	2,984,573	3,008,277					34
3-795 ACSR	2,776,482	8,867,865	11,644,347					35
	139,982,599	1,622,473,524	1,762,456,122	850,039	946,050	2,059,747	3,855,836	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
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9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
3-795 ACSR	37,277	623,112	660,389					1
3-795 ACSR	66,461	787,383	853,844					2
6-795 ACSR	-1	-4,930	-4,931					3
3-795 ACSR		1,140,197	1,140,197					4
3-795 ACSR	684,550	4,125,632	4,810,181					5
3-795 ACSR		305,378	305,378					6
3-795 ACSR	407,271	5,020,073	5,427,343					7
3-795 ACSR								8
3-795 ACSR	286,505	6,288,996	6,575,501					9
3-795 ACSR	891,615	10,915,732	11,807,347					10
3-795 ACSR	1,108,488	7,128,655	8,237,144					11
3-795 ACSR		1,138,599	1,138,599					12
3-795 ACSR	233,588	8,509,174	8,742,763					13
3-795 ACSR								14
3-795 ACSR	1,305,733	12,606,046	13,911,778					15
3-795 ACSR	886,966	13,979,684	14,866,650					16
3-795 ACSR								17
3-795 ACSR								18
3-795 ACSR								19
3-795 ACSR								20
3-795 ACSR								21
3-795 ACSR	1,809,214	18,432,877	20,242,091					22
3-795 ACSR	2,565,040	28,946,409	31,511,449					23
3-795 ACSR								24
3-795 ACSR		1,150,540	1,150,540					25
3-795 ACSR		2,390,467	2,390,467					26
3-795 ACSR	880,706	8,383,885	9,264,591					27
3-795 ACSR	464,861	7,176,410	7,641,271					28
3-795 ACSR								29
3-795 ACSR	943,425	4,865,979	5,809,404					30
3-795 ACSR		1,524,820	1,524,820					31
3-795 ACSR								32
3-795 ACSR		589,226	589,226					33
3-795 ACSR	192,413	3,762,121	3,954,533					34
3-795 ACSR								35
	139,982,599	1,622,473,524	1,762,456,122	850,039	946,050	2,059,747	3,855,836	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
3-795 ACSR								1
3-795 ACSR		768,502	768,502					2
3-795 ACSR	373,453	6,280,883	6,654,336					3
3-795 ACSR		151,855	151,855					4
3-795 ACSR								5
3-795 ACSR								6
3-795 ACSR		186,646	186,646					7
3-795 ACSR								8
3-795 ACSR		80,690	80,690					9
3-795 ACSR	299,576	5,445,810	5,745,386					10
3-795 ACSR	35,679	7,767,507	7,803,186					11
3-795 ACSR	385,284	8,482,427	8,867,711					12
3-795 ACSR								13
6-795 ACSR	1,003,850	4,014,434	5,018,284					14
3-795 ACSR	112,864	4,868,427	4,981,292					15
3-795 ACSR								16
3-1011.3 ACCCULS	10,937	3,883,429	3,894,367					17
3-795 ACSR	74,484	1,818,565	1,893,049					18
3-795 ACSR	691,754	5,466,548	6,158,302					19
3-795 ACSR	80,573	4,882,089	4,962,663					20
3-795 ACSR								21
3-795 ACSR								22
3-795 ACSR	262,396	5,275,737	5,538,133					23
3-795 ACSR								24
3-795 ACSR	194,338	4,499,286	4,693,624					25
3-795 ACSR	86,442	2,528,471	2,614,913					26
3-795 ACSR	104,491	3,191,790	3,296,281					27
3-795 ACSR	71,645	502,725	574,370					28
3-795 ACSR	344,824	4,613,256	4,958,080					29
3-795 ACSR	87,871	646,978	734,849					30
3-795 ACSR	144,944	5,087,899	5,232,842					31
3-795 ACSR								32
3-795 ACCR		-8,522,896	-8,522,896					33
3-795 ACSR	510,050	3,940,495	4,450,546					34
3-795 ACSR								35
	139,982,599	1,622,473,524	1,762,456,122	850,039	946,050	2,059,747	3,855,836	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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3-795 ACSR	10,840	6,820,744	6,831,584					1
3-795 ACSR		5,855,193	5,855,193					2
3-795 ACSR								3
3-795 ACSR	241	740,616	740,857					4
3-795 ACSR								5
3-795 ACSR	10,898	510,118	521,016					6
3-795 ACSR	32,221	3,793,091	3,825,311					7
3-795 ACSS		41,452	41,452					8
3-795 ACCC		121,547	121,547					9
3-795 ACSR	40,416	722,252	762,667					10
3-795 ACSR		281,393	281,393					11
3-795 ACSR		1,256,372	1,256,372					12
3-795 ACSR	177,182	4,994,088	5,171,270					13
3-795 ACSR	98,926	1,230,909	1,329,835					14
3-795 ACSR	205,589	2,560,662	2,766,251					15
3-795 ACSR								16
3-795 ACSR	50,912	3,638,662	3,689,574					17
3-795 ACSR								18
3-795 ACSR	143,180	4,062,886	4,206,066					19
3-795 ACSR		260,013	260,013					20
3-795 ACSR								21
3-795 ACSR	908,602	12,610,310	13,518,912					22
								23
	56,704,708	669,542,465	726,247,173					24
								25
								26
	3,557,482	157,599,701	161,157,183					27
								28
								29
								30
								31
								32
								33
								34
				850,039	946,050	2,059,747	3,855,836	35
	139,982,599	1,622,473,524	1,762,456,122	850,039	946,050	2,059,747	3,855,836	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	(J20;01) HOBBS	KIOWA	47.19	H-FRAME	6.00	1	1
2	(J20;01) HOBBS	KIOWA	0.67	SINGLE POLE	6.00	1	1
3	(J21;01) KIOWA	NORTH LOVING	21.94	H-FRAME	6.00	1	1
4	(J22;01) CHINA DRAW	NORTH LOVING	18.11	H-FRAME	6.00	1	1
5	(J23;01) KIOWA	ROADRUNNER	40.11	H-FRAME	6.00	1	1
6	(U02;01) GREYHOUND	PORTALES INTERCHANGE	8.56	SINGLE POLE	8.00	1	1
7	(U13;01) ROSWELL INTER.	ROSWELL CITY	2.00	SINGLE POLE	9.00	1	1
8	(W38;01) RED BLUFF	WIPP	0.62	SINGLE POLE	23.00	1	1
9	(W40;01) CANON WEST	DEAF SMITH INTERCHANGE	1.51	SINGLE POLE	22.00	1	1
10	(W66;01) GREYHOUND	PORTALES INTERCHANGE	7.35	SINGLE POLE	10.00	1	1
11	(W82;01) HEREFORD NE	LA PLATA	7.34	SINGLE POLE	10.00	1	1
12	(W92;01) ATOKA	EAGLE CREEK	25.25	SINGLE POLE	9.00	1	1
13	(W95;01) CUSTER MTN.	ROADRUNNER	10.89	SINGLE POLE	8.00	1	1
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44	TOTAL		191.54		129.00	13	13

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
6-795	ACSS	26/7	345	8,126,437	31,583,931	6,898,024		46,608,392	1
6-795	ACSS	26/7	345						2
6-795	ACSS	26/7	345		18,233,942	4,269,126		22,503,068	3
6-795	ACSS	26/7	345		14,386,511	4,189,019		18,575,530	4
6-795	ACSR	26/7	345			579,667		579,667	5
3-477	ACSS	26/7	115		4,051,553	643,022		4,694,575	6
3-477	ACSS	26/7	115		1,370,177	633,841		2,004,018	7
3-397.5	ACSR	26/7	115		-54,662	-26,013		-80,675	8
3-477	ACSS	26/7	115	100,713	6,402,361	2,352,446		8,855,520	9
3-477	ACSS	26/7	115	48,537	6,328,496	1,207,455		7,584,488	10
3-477	ACSS	26/7	115		3,395,398	1,150,337		4,545,735	11
3-477	ACSS	26/7	115	385,804	9,498,107	4,757,661		14,641,572	12
3-477	ACSS	26/7	115		2,941,119	849,091		3,790,210	13
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				8,661,491	98,136,933	27,503,676		134,302,100	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 1 Column: a

Construction which impacted less than 0.5 miles of an Operating Circuit are not included in this report

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	34TH STREET PUMP-T1W,T1E,T1	UNATTENDED DISTRIB	13.20	2.40	
2	34TH STREET-TR01	UNATTENDED DISTRIB	115.00	13.20	
3	3RD & WESTERN-T1	UNATTENDED DISTRIB	13.20	4.16	
4	8TH & BONHAM-T1	UNATTENDED DISTRIB	13.20	4.16	
5	8TH & BONHAM-T2	UNATTENDED DISTRIB	13.20	4.16	
6	ADAIR-T1	UNATTENDED DISTRIB	69.00	12.50	
7	ADOBE CREEK-T1	UNATTENDED DISTRIB	69.00	12.50	
8	ADOBE CREEK-T2	UNATTENDED DISTRIB	69.00	4.16	
9	AIKEN RURAL-T1	UNATTENDED DISTRIB	69.00	12.50	
10	ALLMON-T1	UNATTENDED DISTRIB	69.00	12.50	
11	ALLRED-T1	UNATTENDED DISTRIB	69.00	12.50	
12	AMARILLO SOUTH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
13	AMFRAC-T1	UNATTENDED DISTRIB	115.00	2.40	
14	AMHERST-T1	UNATTENDED DISTRIB	69.00	2.40	
15	AMOCO YELLOWHOUSE-T1	UNATTENDED DISTRIB	69.00	12.50	
16	ANDREWS COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
17	ANDREWS COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
18	ANTON WEST-T1	UNATTENDED DISTRIB	69.00	12.50	12.50
19	ARROWHEAD-T1	UNATTENDED DISTRIB	115.00	13.20	
20	ARROWHEAD-T1	UNATTENDED DISTRIB	115.00	13.20	
21	ARTESIA 13TH STREET-T1	UNATTENDED DISTRIB	69.00	4.16	
22	ARTESIA CITY OR TOWN-T1	UNATTENDED DISTRIB	69.00	4.16	
23	ARTESIA COUNTRY CLUB-T1	UNATTENDED TRANSM	12.50	69.00	
24	ARTESIA SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
25	ARTESIA-T1	UNATTENDED TRANSM	115.00	69.00	
26	ARTESIA-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	ATLANTIC-T1W,T1E,T1	UNATTENDED DISTRIB	23.00	2.40	
28	ATOKA-T1	UNATTENDED TRANSM	115.00	69.00	13.20
29	BAILEY COUNTY PUMP-T1	UNATTENDED DISTRIB	69.00	12.50	
30	BAILEY COUNTY-T1	UNATTENDED DISTRIB	69.00	12.50	
31	BAILEY COUNTY-T1E	UNATTENDED DISTRIB	69.00	12.50	
32	BAILEY COUNTY-T1W	UNATTENDED DISTRIB	69.00	12.50	
33	BAILEY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	
34	BAILEY COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	13.20
35	BAINER-T1W,T1E,T1	UNATTENDED DISTRIB	69.00	2.40	
36	BARWISE-T1	UNATTENDED DISTRIB	69.00	12.50	
37	BATTLE AXE-T1	UNATTENDED DISTRIB	115.00	13.20	
38	BATTLE AXE-T2	UNATTENDED DISTRIB	115.00	13.20	
39	BENNETT-T1	UNATTENDED DISTRIB	115.00	13.20	
40	BLACKHAWK-T1	UNATTENDED TRANSM	115.00	69.00	13.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BLACKHAWK-T2	UNATTENDED TRANSM	115.00	69.00	13.20
2	BLODGETT-T1	UNATTENDED DISTRIB	12.50	2.40	
3	BOARDMAN-T1	UNATTENDED DISTRIB	69.00	12.50	
4	BOLTON PUMP-T1	UNATTENDED DISTRIB	12.50	2.40	
5	BONBRIGHT-T1	UNATTENDED DISTRIB	12.50	2.40	
6	BONBRIGHT-T2	UNATTENDED DISTRIB	12.50	2.40	
7	BOOKER-T1	UNATTENDED DISTRIB	69.00	34.50	
8	BOOKER-T2	UNATTENDED DISTRIB	69.00	4.16	
9	BORGER ISOM-T1	UNATTENDED DISTRIB	13.20	4.16	
10	BORGER NORTH-T1	UNATTENDED DISTRIB	12.50	4.16	
11	BORGER WEST-T1	UNATTENDED DISTRIB	115.00	13.20	
12	BOWERS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
13	BOWERS-T2	UNATTENDED TRANSM	115.00	69.00	13.20
14	BOWERS-T3	UNATTENDED TRANSM	115.00	69.00	13.20
15	BRASHER-T1	UNATTENDED DISTRIB	115.00	13.20	
16	BRISCOE COUNTY-T1	UNATTENDED DISTRIB	69.00	23.00	
17	BROWNFIELD SWITCHING-T1	UNATTENDED DISTRIB	69.00	23.00	
18	BUCKEYE-T1	UNATTENDED DISTRIB	115.00	12.50	
19	BUFFALO-T1	UNATTENDED DISTRIB	69.00	12.50	
20	BURNETT-T1	UNATTENDED DISTRIB	69.00	13.20	
21	BUSHLAND-T1	UNATTENDED TRANSM	230.00	115.00	13.20
22	BUSH-T1	UNATTENDED DISTRIB	115.00	13.80	
23	BYRD-T1	UNATTENDED DISTRIB	115.00	4.16	
24	CAMEX TRANSPETCO-T1	UNATTENDED DISTRIB	69.00	4.16	
25	CAMEX TRANSPETCO-T2	UNATTENDED DISTRIB	69.00	4.16	
26	CAMEX TRANSPETCO-T3	UNATTENDED DISTRIB	69.00	13.20	
27	CAMPBELL ST-T1	UNATTENDED DISTRIB	115.00	12.50	
28	CANADIAN-T1	UNATTENDED DISTRIB	69.00	4.16	
29	CANNON AFB-T1	UNATTENDED DISTRIB	115.00	13.20	
30	CANYON EAST-T1	UNATTENDED DISTRIB	115.00	13.20	
31	CANYON WEST-TR01	UNATTENDED DISTRIB	115.00	13.20	
32	CAPITAN-T1	UNATTENDED DISTRIB	115.00	13.20	
33	CARLISLE-T1	UNATTENDED TRANSM	230.00	115.00	13.20
34	CARLISLE-T2	UNATTENDED TRANSM	115.00	69.00	13.20
35	CARLISLE-T3	UNATTENDED DISTRIB	115.00	23.00	
36	CARLSBAD CAVERN-T1W,T1E,T1	UNATTENDED DISTRIB	12.50	2.40	
37	CARLSBAD WATERFIELD-T1	UNATTENDED DISTRIB	69.00	23.00	
38	CARLSBAD-T1	UNATTENDED TRANSM	115.00	69.00	13.20
39	CARLSBAD-T2	UNATTENDED TRANSM	115.00	69.00	
40	CARLSBAD-T3	UNATTENDED DISTRIB	69.00	13.20	

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CARSON CO-T1	UNATTENDED DISTRIB	115.00	13.80	
2	CASTRO COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
3	CASTRO COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	
4	CEDAR LAKE EAST-T1W,T1E,T1	UNATTENDED DISTRIB	69.00	12.50	
5	CENTRE STREET-T1	UNATTENDED DISTRIB	69.00	13.20	
6	CHANNING-T1	UNATTENDED DISTRIB	230.00	34.50	19.90
7	CHANNING-T2	UNATTENDED DISTRIB	230.00	34.50	19.90
8	CHAVES COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
9	CHAVES COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
10	CHAVES COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	
11	CHERRY STREET-T1	UNATTENDED DISTRIB	115.00	13.20	
12	CHINADRAW-SVC	UNATTENDED TRANSM	115.00	69.00	
13	CHINADRAW-TR01	UNATTENDED DISTRIB	115.00	13.20	
14	CHINADRAW-TR02	UNATTENDED DISTRIB	115.00	13.20	
15	CLIFFSIDE-T1	UNATTENDED DISTRIB	69.00	4.16	
16	CLOSE CITY-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
17	CLOVIS CITY-T1	UNATTENDED DISTRIB	23.00	4.16	
18	CLOVIS EAST-T1	UNATTENDED DISTRIB	115.00	13.20	
19	CLOVIS NORTH-T1	UNATTENDED DISTRIB	115.00	12.50	
20	CLOVIS PARK EAST-T1	UNATTENDED DISTRIB	23.00	4.16	
21	CLOVIS WEST-T1	UNATTENDED DISTRIB	115.00	13.20	
22	CLOVIS WEST-T2	UNATTENDED DISTRIB	69.00	23.00	
23	COBLE-T1	UNATTENDED DISTRIB	69.00	12.50	
24	COBURN CREEK-T1	UNATTENDED DISTRIB	115.00	13.20	
25	COCHRAN COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
26	COCHRAN COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	CONE-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
28	CONWAY-T1	UNATTENDED DISTRIB	115.00	13.20	
29	COOPER RANCH-T1	UNATTENDED DISTRIB	115.00	13.20	
30	CORTEZ-T1	UNATTENDED DISTRIB	115.00	4.16	2.40
31	COTTONWOOD-T1	UNATTENDED DISTRIB	69.00	12.50	
32	COULTER-T1	UNATTENDED DISTRIB	115.00	13.80	
33	COULTER-T2	UNATTENDED TRANSM	115.00	69.00	
34	COUNTY LINE-T1	UNATTENDED DISTRIB	69.00	12.50	2.40
35	COX-T1	UNATTENDED TRANSM	115.00	69.00	13.20
36	CRMWA #1-T1	UNATTENDED DISTRIB	115.00	4.16	
37	CRMWA #22-T1	UNATTENDED DISTRIB	69.00	4.16	
38	CRMWA #23-T1	UNATTENDED DISTRIB	69.00	13.80	
39	CRMWA #2-T1	UNATTENDED DISTRIB	115.00	4.16	
40	CRMWA #3-T1	UNATTENDED DISTRIB	115.00	4.16	

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS

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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.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CRMWA #4-T1	UNATTENDED DISTRIB	115.00	4.16	
2	CROSBY COUNTY INTERCHANGE-T1	UNATTENDED TRANSM	115.00	69.00	13.20
3	CROSBY COUNTY INTERCHANGE-T2	UNATTENDED TRANSM	115.00	69.00	13.20
4	CROSBYTON-T1	UNATTENDED DISTRIB	23.00	4.16	
5	CROUSE-HINDS-T1	UNATTENDED DISTRIB	115.00	13.80	
6	CUNNINGHAM-T1	UNATTENDED TRANSM	230.00	115.00	13.20
7	CURRY COUNTY-T1	UNATTENDED DISTRIB	69.00	2.40	
8	CURRY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
9	CURRY COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	13.20
10	DALHART-T1	UNATTENDED DISTRIB	69.00	2.40	
11	DALHART-T2	UNATTENDED TRANSM	115.00	69.00	13.20
12	DALHART-T3	UNATTENDED DISTRIB	69.00	12.50	
13	DALHART-T4	UNATTENDED DISTRIB	69.00	34.50	
14	DALLAM COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
15	DAMRON-T1	UNATTENDED DISTRIB	69.00	13.20	
16	DAMRON-T2	UNATTENDED DISTRIB	13.20	2.40	
17	DARROUZETT-T1W,T1E,T1	UNATTENDED DISTRIB	34.50	4.16	
18	DAWN-T1	UNATTENDED DISTRIB	115.00	13.20	
19	DEAF SMITH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
20	DEAF SMITH-T2	UNATTENDED TRANSM	230.00	115.00	13.20
21	DEAF SMITH-T3	UNATTENDED DISTRIB	115.00	13.80	
22	DENVER CITY EAST-T1	UNATTENDED DISTRIB	69.00	7.20	
23	DENVER CITY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
24	DENVER CITY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
25	DEXTER INTERCHANGE-T1	UNATTENDED DISTRIB	69.00	34.50	
26	DEXTER-T1	UNATTENDED DISTRIB	69.00	4.16	
27	DIAMONDBACK-T1	UNATTENDED TRANSM	115.00	69.00	13.20
28	DIEKEMPER-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	4.16	
29	DIMMITT EAST-T1	UNATTENDED DISTRIB	69.00	13.20	
30	DIMMITT SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
31	DOLLARHIDE-T1	UNATTENDED DISTRIB	115.00	12.50	
32	DOSS-T1	UNATTENDED DISTRIB	69.00	23.00	
33	DOSS-T2	UNATTENDED DISTRIB	69.00	12.50	
34	DOSS-T3	UNATTENDED TRANSM	115.00	69.00	
35	DRINKARD-T1	UNATTENDED DISTRIB	115.00	12.50	
36	DUMAS 19TH STREET-T1	UNATTENDED DISTRIB	115.00	34.50	
37	DUMAS 19TH STREET-T2	UNATTENDED DISTRIB	115.00	12.50	
38	DUMAS EAST-T1	UNATTENDED DISTRIB	34.50	12.50	
39	DUMAS HELIUM-T1	UNATTENDED DISTRIB	34.50	12.50	
40	DUMAS NORTH-T1	UNATTENDED DISTRIB	34.50	2.40	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	DUMAS SOUTH-T1	UNATTENDED DISTRIB	34.50	2.40	
2	DUVAL #3-T1	UNATTENDED DISTRIB	69.00	4.16	
3	EAGLE CREEK-T1	UNATTENDED TRANSM	115.00	69.00	13.20
4	EAST PLANT-T1	UNATTENDED DISTRIB	115.00	13.20	
5	EAST PLANT-T2	UNATTENDED TRANSM	230.00	115.00	13.20
6	EAST PLANT-T3	UNATTENDED TRANSM	115.00	69.00	13.20
7	EAST PLANT-T4	UNATTENDED TRANSM	115.00	69.00	
8	EAST PLANT-T5W,T5E,T5	UNATTENDED DISTRIB	13.20	2.40	
9	EAST SANGER-T1	UNATTENDED DISTRIB	115.00	12.50	
10	EDDY COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
11	EDDY COUNTY-T2	UNATTENDED DISTRIB	230.00	8.50	
12	EDDY COUNTY-T3	UNATTENDED TRANSM	345.00	230.00	
13	EDDY COUNTY-T4	UNATTENDED TRANSM	230.00	115.00	13.20
14	EFDC GRAIN POWER PORTALES NM-T1	UNATTENDED DISTRIB	69.00	4.16	
15	ELBERT-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
16	ELLWOOD-T1	UNATTENDED DISTRIB	69.00	12.50	
17	ESTACADO-T1	UNATTENDED DISTRIB	115.00	13.20	
18	ESTACADO-T2	UNATTENDED DISTRIB	115.00	13.20	
19	ETTER RURAL-T1	UNATTENDED DISTRIB	115.00	34.50	
20	ETTER RURAL-T2	UNATTENDED DISTRIB	115.00	34.50	
21	EUNICE-T1	UNATTENDED DISTRIB	115.00	13.20	
22	EXELL-T1	UNATTENDED DISTRIB	115.00	12.50	
23	FAIN-T1	UNATTENDED DISTRIB	115.00	12.50	
24	FARMERS-T1	UNATTENDED DISTRIB	115.00	13.20	
25	FARWELL-T1	UNATTENDED DISTRIB	69.00	2.40	
26	FIESTA-T1	UNATTENDED DISTRIB	115.00	12.50	
27	FLANAGAN-T1	UNATTENDED DISTRIB	69.00	12.50	
28	FLOYD COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
29	FLOYD COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
30	FLOYDADA CITY-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
31	FLOYDADA CITY-T2S,T2N,T2	UNATTENDED DISTRIB	23.00	2.40	
32	FLOYDADA CITY-T3	UNATTENDED DISTRIB	24.00	13.80	
33	FLOYDADA SOUTH-T1	UNATTENDED DISTRIB	69.00	23.00	
34	FOLLETT-T1S,T1,T1N	UNATTENDED DISTRIB	34.50	4.16	
35	FRIONA CITY-T1	UNATTENDED DISTRIB	23.00	2.40	
36	FRIONA RURAL-T1	UNATTENDED DISTRIB	115.00	23.00	
37	FRITCH-T1	UNATTENDED DISTRIB	115.00	13.20	
38	GAINES COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
39	GAINES COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
40	GARZA-T1	UNATTENDED DISTRIB	69.00	23.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	GARZA-T2	UNATTENDED DISTRIB	69.00	23.00	
2	GARZA-T3	UNATTENDED DISTRIB	69.00	2.40	
3	GOODPASTURE-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	12.50	
4	GRAHAM-T1	UNATTENDED TRANSM	115.00	69.00	13.20
5	GRAHAM-T2	UNATTENDED TRANSM	115.00	69.00	13.20
6	GRAPEVINE-T1	UNATTENDED TRANSM	230.00	115.00	13.20
7	GRASSLAND-T1	UNATTENDED TRANSM	230.00	115.00	13.20
8	GRAY COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
9	GREEN HEIGHTS-T1	UNATTENDED DISTRIB	12.50	2.40	
10	GRUVER-T1	UNATTENDED DISTRIB	34.50	12.50	
11	HAGERMAN TOWN-T1	UNATTENDED DISTRIB	23.00	4.16	
12	HAGERMAN WEST RURAL-T1	UNATTENDED DISTRIB	34.50	2.40	
13	HALE CENTER-T1	UNATTENDED DISTRIB	69.00	13.20	
14	HALE COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
15	HALE COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
16	HAPPY CITY-T1	UNATTENDED DISTRIB	69.00	12.50	
17	HAPPY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
18	HAPPY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
19	HARTLEY-T1S,T1N,T1	UNATTENDED DISTRIB	34.50	2.40	
20	HART-T1	UNATTENDED DISTRIB	115.00	13.20	
21	HASTINGS-T1	UNATTENDED DISTRIB	115.00	13.20	
22	HENDRICKS-T1	UNATTENDED DISTRIB	69.00	23.00	
23	HEREFORD CITY-T1	UNATTENDED DISTRIB	69.00	13.80	
24	HEREFORD NORTH EAST-T1	UNATTENDED TRANSM	115.00	69.00	13.20
25	HEREFORD NORTH EAST-T2	UNATTENDED TRANSM	115.00	69.00	13.20
26	HEREFORD SOUTH-T1	UNATTENDED TRANSM	115.00	69.00	
27	HEREFORD-T1	UNATTENDED TRANSM	115.00	69.00	13.20
28	HERRING-T1	UNATTENDED DISTRIB	115.00	34.50	
29	HIGG EAST-T1	UNATTENDED DISTRIB	115.00	13.20	
30	HIGGINS-T1W,T1E,T1	UNATTENDED DISTRIB	34.50	4.16	
31	HIGHLAND PARK-T1	UNATTENDED DISTRIB	115.00	13.80	
32	HITCHLAND-T1	UNATTENDED TRANSM	345.00	230.00	
33	HITCHLAND-T2	UNATTENDED TRANSM	230.00	115.00	13.20
34	HITCHLAND-T3	UNATTENDED TRANSM	345.00	230.00	
35	HOBBS GENERATING-T1	UNATTENDED TRANSM	230.00	115.00	13.20
36	HOBBS GENERATING-T2	UNATTENDED TRANSM	230.00	115.00	13.20
37	HOBBS NE-T1	UNATTENDED DISTRIB	115.00	12.50	
38	HOBBS NORTH-T1	UNATTENDED DISTRIB	115.00	12.50	
39	HOBBS NORTH-T2	UNATTENDED DISTRIB	115.00	12.50	
40	HOBBS SOUTH-T1	UNATTENDED DISTRIB	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HOBBS SOUTH-T2	UNATTENDED DISTRIB	115.00	13.20	
2	HOBGOOD-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	2.40	
3	HOCKLEY COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
4	HOCKLEY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
5	HOPI-T1	UNATTENDED DISTRIB	115.00	13.20	
6	HOWARD-T1	UNATTENDED DISTRIB	115.00	13.20	
7	HOWARD-T2	UNATTENDED TRANSM	115.00	69.00	13.20
8	HOWARD-T3	UNATTENDED TRANSM	115.00	69.00	13.20
9	HUTCHINSON COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
10	HUTCHINSON COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
11	HUTCHINSON COUNTY-T3	UNATTENDED TRANSM	230.00	115.00	13.20
12	HVDC TIE-T2	UNATTENDED TRANSM	230.00	115.00	
13	HVDC TIE-T3	UNATTENDED DISTRIB	345.00	34.50	
14	IDALOU-T1	UNATTENDED DISTRIB	23.00	4.16	
15	IMC #4-T1	UNATTENDED DISTRIB	69.00	13.20	
16	INDUSTRIAL-T1	UNATTENDED DISTRIB	69.00	13.20	
17	IRICK-T1	UNATTENDED DISTRIB	69.00	13.20	
18	JAL-T1	UNATTENDED DISTRIB	115.00	13.80	
19	JAYBEE-T1	UNATTENDED DISTRIB	69.00	12.50	
20	KERRICK PUMP-T1S,T1N,T1	UNATTENDED DISTRIB	34.50	2.40	
21	KILGORE-T1	UNATTENDED DISTRIB	115.00	13.20	
22	KINGSMILL-T1	UNATTENDED DISTRIB	115.00	12.50	15.00
23	KINGSMILL-T2	UNATTENDED TRANSM	115.00	69.00	13.20
24	KINGSMILL-T3	UNATTENDED DISTRIB	69.00	13.80	
25	KINNEY-T1W,T1E,T1	UNATTENDED DISTRIB	69.00	2.40	
26	KISER-T1	UNATTENDED TRANSM	115.00	69.00	13.20
27	KITE-T1	UNATTENDED DISTRIB	69.00	13.20	
28	KRESS RURAL-T1	UNATTENDED DISTRIB	115.00	13.20	
29	KRESS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
30	LAKE MEREDITH-T1	UNATTENDED DISTRIB	115.00	4.16	
31	LAMB COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
32	LAMB COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
33	LAMB COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	13.20
34	LAMTON-T1	UNATTENDED TRANSM	115.00	69.00	13.20
35	LARIAT-T1	UNATTENDED DISTRIB	69.00	12.50	
36	LAWRENCE PARK-T1	UNATTENDED DISTRIB	69.00	13.80	
37	LAWRENCE PARK-T2	UNATTENDED DISTRIB	69.00	13.80	
38	LEA NATIONAL-T1	UNATTENDED DISTRIB	115.00	12.50	
39	LEA ROAD-T1	UNATTENDED DISTRIB	115.00	12.50	
40	LEGACY-T1	UNATTENDED TRANSM	115.00	69.00	13.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LEHMAN-T1	UNATTENDED DISTRIB	115.00	12.50	
2	LEVELLAND CITY-T1	UNATTENDED DISTRIB	69.00	12.50	
3	LEVELLAND CITY-T2W,T2E,T2	UNATTENDED DISTRIB	12.50	2.40	
4	LEVELLAND CITY-T3W,T3E,T3	UNATTENDED DISTRIB	69.00	2.40	
5	LEVELLAND EAST-T1	UNATTENDED DISTRIB	69.00	12.50	
6	LIPSCOMB CO-T1	UNATTENDED DISTRIB	115.00	34.50	
7	LIPSCOMB CO-T2	UNATTENDED DISTRIB	115.00	13.20	
8	LITTLEFIELD CITY-T1	UNATTENDED DISTRIB	69.00	4.16	
9	LITTLEFIELD SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
10	LITTLEFIELD WEST-T1	UNATTENDED DISTRIB	69.00	12.50	
11	LITTLEFIELD WEST-T1W,T1E	UNATTENDED DISTRIB	69.00	7.20	
12	LIVINGSTON RIDGE-T1	UNATTENDED DISTRIB	69.00	12.50	
13	LOCKNEY CITY-T1	UNATTENDED DISTRIB	23.00	12.50	
14	LOCKNEY RURAL-T1	UNATTENDED DISTRIB	69.00	23.00	
15	LOCKNEY RURAL-T2W,T2E,T2	UNATTENDED DISTRIB	69.00	12.50	
16	LOCKNEY WEST-T1	UNATTENDED DISTRIB	23.00	7.20	
17	LORENZO-T1	UNATTENDED DISTRIB	23.00	4.16	
18	LOVING SOUTH-T1	UNATTENDED DISTRIB	69.00	13.20	
19	LUBBOCK EAST-T1	UNATTENDED TRANSM	230.00	115.00	13.20
20	LUBBOCK EAST-T2	UNATTENDED TRANSM	115.00	69.00	13.20
21	LUBBOCK EAST-T3	UNATTENDED TRANSM	115.00	69.00	13.20
22	LUBBOCK SOUTH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
23	LUBBOCK SOUTH-T2	UNATTENDED TRANSM	115.00	69.00	13.20
24	LUBBOCK SOUTH-T3	UNATTENDED TRANSM	230.00	115.00	13.20
25	LYNN COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
26	LYNN COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	LYNN COUNTY-T3	UNATTENDED DISTRIB	115.00	23.00	
28	LYONS-T1	UNATTENDED DISTRIB	69.00	13.80	
29	MAGNOLIA PUMP STATION-T1	UNATTENDED DISTRIB	24.00	2.40	
30	MALJAMAR #1-T1	UNATTENDED DISTRIB	115.00	12.50	
31	MALJAMAR 2-T1	UNATTENDED DISTRIB	115.00	12.50	
32	MALLET-T1	UNATTENDED DISTRIB	69.00	12.50	
33	MANHATTAN-T1	UNATTENDED DISTRIB	115.00	13.20	
34	MARKET STREET-T1	UNATTENDED DISTRIB	69.00	12.50	
35	MCCLELLAN PUMP-T1	UNATTENDED DISTRIB	115.00	13.20	
36	MCCULLOUGH-T1	UNATTENDED DISTRIB	69.00	13.20	
37	MCLEAN RURAL-T1	UNATTENDED DISTRIB	115.00	13.20	
38	MID AMERICA #3-T1	UNATTENDED DISTRIB	69.00	2.40	
39	MID-AMERICA #2-T1	UNATTENDED DISTRIB	69.00	2.40	
40	MIDDLETON-T1	UNATTENDED DISTRIB	69.00	12.50	

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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.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MILLEN-T1	UNATTENDED DISTRIB	115.00	7.20	
2	MITCHELL STREET-T1	UNATTENDED DISTRIB	23.00	4.16	
3	MONROE-T1	UNATTENDED DISTRIB	69.00	23.00	
4	MONUMENT-T1	UNATTENDED DISTRIB	115.00	12.50	
5	MOORE COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
6	MOORE COUNTY-T2	UNATTENDED DISTRIB	115.00	13.20	
7	MORTON-T1	UNATTENDED DISTRIB	69.00	4.16	
8	MOSS-T1	UNATTENDED DISTRIB	69.00	23.00	
9	MULESHOE VALLEY-T1	UNATTENDED DISTRIB	115.00	13.20	
10	MULESHOE WEST-T1	UNATTENDED DISTRIB	69.00	12.50	
11	MURPHY-T1	UNATTENDED DISTRIB	115.00	23.00	
12	MUSTANG-T1	UNATTENDED TRANSM	230.00	115.00	13.20
13	NAVAJO #1-T1	UNATTENDED DISTRIB	69.00	2.40	
14	NAVAJO #2-T1	UNATTENDED DISTRIB	115.00	4.16	
15	NAVAJO #3-T1	UNATTENDED DISTRIB	115.00	4.16	
16	NAVAJO #4-T1	UNATTENDED DISTRIB	69.00	2.40	
17	NAVAJO #5-T1	UNATTENDED DISTRIB	115.00	4.16	
18	NAVAJO-MALAGA-T1	UNATTENDED DISTRIB	69.00	4.16	
19	NEWHART-T1	UNATTENDED TRANSM	230.00	115.00	13.20
20	NICHOLS-T7	UNATTENDED TRANSM	230.00	115.00	13.20
21	NICHOLS-T8	UNATTENDED TRANSM	230.00	115.00	13.20
22	NM POTASH #2-T1	UNATTENDED DISTRIB	69.00	13.80	
23	NORRIS ST-T1	UNATTENDED DISTRIB	115.00	13.20	
24	NORTH CANAL-T1	UNATTENDED DISTRIB	115.00	12.50	
25	NORTH LOVING-T1	UNATTENDED DISTRIB	115.00	13.20	
26	NORTHWEST-T1	UNATTENDED TRANSM	115.00	69.00	
27	OASIS-T1	UNATTENDED TRANSM	230.00	115.00	13.20
28	OCHILTREE-T1	UNATTENDED TRANSM	230.00	115.00	
29	OCHOA-T1	UNATTENDED DISTRIB	115.00	13.20	
30	OCOTILLO-T1	UNATTENDED DISTRIB	115.00	13.20	
31	OLTON-T1	UNATTENDED DISTRIB	69.00	7.20	
32	ONG-T1	UNATTENDED DISTRIB	13.20	4.16	
33	OSAGE PUMP-T1W,T1E,T1	UNATTENDED DISTRIB	13.20	2.40	
34	OSAGE PUMP-T2S,T2N,T2	UNATTENDED DISTRIB	13.20	2.40	
35	OSAGE-T1	UNATTENDED DISTRIB	115.00	13.20	
36	OWENS-CORNING-T1	UNATTENDED DISTRIB	115.00	13.80	
37	OWENS-CORNING-T2	UNATTENDED DISTRIB	115.00	13.80	
38	PACIFIC-T1	UNATTENDED DISTRIB	115.00	12.50	
39	PALO DURO-T1	UNATTENDED DISTRIB	115.00	13.20	
40	PARMER COUNTY-T1	UNATTENDED DISTRIB	115.00	23.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PCA-T1	UNATTENDED TRANSM	115.00	69.00	13.20
2	PCA-T2	UNATTENDED DISTRIB	69.00	13.20	
3	PEARL-T1	UNATTENDED DISTRIB	115.00	12.50	
4	PECOS-T1	UNATTENDED TRANSM	230.00	115.00	
5	PECOS-T2	UNATTENDED DISTRIB	115.00	13.20	
6	PERIMETER-T1	UNATTENDED DISTRIB	115.00	13.20	
7	PERRYTON SOUTH-T2	UNATTENDED DISTRIB	115.00	12.50	
8	PERRYTON-T1	UNATTENDED DISTRIB	115.00	12.50	
9	PERRYTON-T4S,T4N,T4	UNATTENDED TRANSM	115.00	69.00	
10	PHILLIPS PUMP #1-T1	UNATTENDED DISTRIB	69.00	2.40	
11	PHILLIPS PUMP #2-T1	UNATTENDED DISTRIB	69.00	2.40	
12	PIERCE STREET-T1	UNATTENDED DISTRIB	115.00	13.20	
13	PLAINVIEW CITY-T1W,T1E,T1,T1	UNATTENDED DISTRIB	69.00	2.40	
14	PLAINVIEW CITY-T2W,T2E,T2	UNATTENDED DISTRIB	69.00	2.40	
15	PLAINVIEW EAST-T1	UNATTENDED DISTRIB	69.00	12.50	
16	PLAINVIEW NORTH-T1	UNATTENDED DISTRIB	115.00	13.20	
17	PLAINVIEW SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
18	PLAINVIEW WESTRIDGE-T1	UNATTENDED DISTRIB	69.00	7.20	
19	PLAINVIEW WEST-T1	UNATTENDED DISTRIB	69.00	12.50	
20	PLANT X-T1	UNATTENDED TRANSM	230.00	115.00	13.20
21	PLANT X-T19	UNATTENDED DISTRIB	115.00	12.50	
22	PLEASANT HILL-T1	UNATTENDED TRANSM	230.00	115.00	13.20
23	PORTALES #1-T1	UNATTENDED DISTRIB	69.00	4.16	
24	PORTALES #2-T1	UNATTENDED DISTRIB	69.00	12.50	7.20
25	PORTALES #2-T2	UNATTENDED DISTRIB	69.00	4.16	
26	PORTALES INTERCHANGE-T1	UNATTENDED TRANSM	115.00	69.00	13.20
27	PORTALES INTERCHANGE-T2	UNATTENDED TRANSM	115.00	69.00	13.20
28	PORTALES SOUTH-T1	UNATTENDED DISTRIB	69.00	4.16	
29	PORTALES WATERFIELD-T1	UNATTENDED DISTRIB	115.00	13.20	
30	POTASH JUNCTION-T1	UNATTENDED TRANSM	230.00	115.00	13.20
31	POTASH JUNCTION-T2	UNATTENDED TRANSM	115.00	69.00	13.20
32	POTASH JUNCTION-T3	UNATTENDED TRANSM	115.00	69.00	13.20
33	POTTER COUNTY-T1	UNATTENDED TRANSM	345.00	230.00	13.20
34	POTTER COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	
35	POTTER COUNTY-T3	UNATTENDED TRANSM	230.00	115.00	13.20
36	PRENTICE-T1	UNATTENDED DISTRIB	115.00	12.50	
37	PRICE-T1	UNATTENDED DISTRIB	69.00	12.50	
38	PRINGLE OIL FIELD-T1	UNATTENDED DISTRIB	34.50	12.50	
39	PRINGLE-T1	UNATTENDED TRANSM	230.00	115.00	13.20
40	PRINGLE-T2	UNATTENDED DISTRIB	115.00	34.50	

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	PUCKETT WEST-T1	UNATTENDED DISTRIB	115.00	13.20	
2	PULLMAN-T1	UNATTENDED DISTRIB	115.00	13.20	
3	RALLS-T1W,T1E,T1	UNATTENDED DISTRIB	23.00	2.40	
4	RANDALL COUNTY-T1	UNATTENDED DISTRIB	230.00	13.20	
5	RANDALL COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
6	RIAC EAST-T1	UNATTENDED DISTRIB	13.20	4.16	
7	RIAC WEST-T1	UNATTENDED DISTRIB	34.50	2.40	
8	RILEY-T1	UNATTENDED DISTRIB	69.00	7.20	
9	RIVERVIEW-T2	UNATTENDED DISTRIB	115.00	13.20	
10	RIVERVIEW-T3	UNATTENDED TRANSM	115.00	69.00	
11	ROADRUNNER-T1	UNATTENDED TRANSM	230.00	115.00	13.20
12	ROADRUNNER-T2 SVC	UNATTENDED TRANSM	345.00	115.00	13.20
13	ROBERTS COUNTY-T1 NEW	UNATTENDED DISTRIB	69.00	7.20	
14	ROLLING HILLS-T1	UNATTENDED TRANSM	230.00	115.00	13.20
15	ROOSEVELT COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
16	ROSWELL CITY-T1	UNATTENDED DISTRIB	115.00	13.20	
17	ROSWELL CITY-T2	UNATTENDED DISTRIB	115.00	13.20	
18	ROSWELL-T1	UNATTENDED TRANSM	115.00	69.00	13.20
19	ROSWELL-T2	UNATTENDED TRANSM	115.00	69.00	13.20
20	ROUND UP-T1S,T1N,T1	UNATTENDED DISTRIB	13.20	2.40	
21	ROXANNA-T1	UNATTENDED DISTRIB	69.00	13.20	
22	RUSSELL POOL-T1	UNATTENDED DISTRIB	115.00	12.50	
23	RUSSELL POOL-T2	UNATTENDED DISTRIB	115.00	13.20	
24	SAGE BRUSH-T1	UNATTENDED DISTRIB	115.00	23.00	
25	SAMSON-T1	UNATTENDED DISTRIB	115.00	12.50	
26	SAN JACINTO-T1S,T1N,T1	UNATTENDED DISTRIB	13.20	2.40	
27	SAND DUNES-T1	UNATTENDED DISTRIB	115.00	13.20	
28	SEAGRAVES INTERCHANGE-T1	UNATTENDED TRANSM	115.00	69.00	13.20
29	SEMINOLE CITY-T1	UNATTENDED DISTRIB	23.00	2.40	
30	SEMINOLE INTG-T1	UNATTENDED TRANSM	230.00	115.00	13.20
31	SEMINOLE INTG-T2	UNATTENDED TRANSM	230.00	115.00	13.20
32	SEMINOLE INTG-T3	UNATTENDED DISTRIB	115.00	23.00	
33	SEVEN RIVERS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
34	SEVEN RIVERS-T2	UNATTENDED TRANSM	230.00	115.00	13.80
35	SHALLOWATER-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
36	SHAMROCK PUMP-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	2.40	
37	SHELL C2 COMPRESSOR-T1	UNATTENDED DISTRIB	115.00	4.16	
38	SHELL C3-T1	UNATTENDED DISTRIB	115.00	12.50	
39	SHERMAN COUNTY-T1	UNATTENDED DISTRIB	115.00	34.50	
40	SILVERTON CITY-T1	UNATTENDED DISTRIB	23.00	2.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SLATON-T1	UNATTENDED DISTRIB	69.00	23.00	
2	SLATON-T2	UNATTENDED DISTRIB	69.00	4.16	
3	SLAUGHTER-T1	UNATTENDED DISTRIB	69.00	2.40	
4	SMITH-T1	UNATTENDED DISTRIB	69.00	4.16	
5	SNEED-T1	UNATTENDED DISTRIB	34.50	12.50	
6	SONCY-T1	UNATTENDED DISTRIB	69.00	13.80	
7	SOUTH GEORGIA-T1	UNATTENDED TRANSM	115.00	69.00	
8	SOUTH GEORGIA-T2	UNATTENDED DISTRIB	115.00	13.80	
9	SOUTH GEORGIA-T3	UNATTENDED DISTRIB	115.00	12.50	
10	SOUTH PLAINS-T1W,T1E,T1	UNATTENDED DISTRIB	23.00	4.16	
11	SOUTHEAST-T1	UNATTENDED DISTRIB	115.00	13.20	
12	SOUTHLAND-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	2.40	
13	SPEARMAN CITY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
14	SPEARMAN CITY-T2	UNATTENDED DISTRIB	115.00	4.16	
15	SPEARMAN INTG-T1	UNATTENDED TRANSM	115.00	69.00	13.20
16	SPEARMAN INTG-T2	UNATTENDED DISTRIB	69.00	34.50	
17	SPRING CREEK-T1	UNATTENDED DISTRIB	69.00	13.80	
18	SPRING DRAW-T1	UNATTENDED DISTRIB	115.00	13.20	
19	SPRINGLAKE-T1	UNATTENDED DISTRIB	69.00	12.50	
20	STINNETT-T1	UNATTENDED DISTRIB	34.50	12.50	
21	STRATA-T1	UNATTENDED DISTRIB	69.00	12.50	
22	STRATFORD-T1	UNATTENDED DISTRIB	34.50	2.40	
23	STRATFORD-T2	UNATTENDED DISTRIB	34.50	12.50	
24	SUDAN RURAL-T1	UNATTENDED DISTRIB	69.00	12.50	
25	SULPHUR SPRINGS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
26	SULPHUR SPRINGS-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	SUNDOWN-T1	UNATTENDED TRANSM	230.00	115.00	13.20
28	SUNRAY-T1W,T1E,T1	UNATTENDED DISTRIB	34.50	7.20	
29	SUNSET-T1	UNATTENDED DISTRIB	115.00	13.20	
30	SUNSET-T2	UNATTENDED DISTRIB	115.00	13.20	
31	SWISHER COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
32	TAHOKA CITY-T1	UNATTENDED DISTRIB	23.00	2.40	
33	TASCOSA-T1	UNATTENDED DISTRIB	34.50	13.20	
34	TEAGUE-T1	UNATTENDED DISTRIB	115.00	12.50	
35	TENNECO-T1	UNATTENDED DISTRIB	69.00	12.50	
36	TERRY COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
37	TERRY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
38	TEXACO-T1	UNATTENDED DISTRIB	69.00	12.50	
39	TEXAS FARMS-T1	UNATTENDED DISTRIB	115.00	13.20	
40	TMC-T1	UNATTENDED DISTRIB	69.00	12.50	

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TOKIO-T1	UNATTENDED DISTRIB	69.00	12.50	
2	TOLK-T1	UNATTENDED TRANSM	345.00	230.00	13.20
3	TUCO-T1	UNATTENDED TRANSM	345.00	230.00	13.20
4	TUCO-T12	UNATTENDED TRANSM	115.00	69.00	13.20
5	TUCO-T2	UNATTENDED TRANSM	230.00	115.00	13.20
6	TUCO-T3	UNATTENDED TRANSM	115.00	69.00	13.20
7	TUCO-T4	UNATTENDED TRANSM	115.00	69.00	13.20
8	TUCO-T5	UNATTENDED DISTRIB	69.00	12.50	
9	TUCO-T6 SVC	UNATTENDED DISTRIB	230.00	13.20	
10	TUCO-T7	UNATTENDED TRANSM	230.00	115.00	
11	TUCO-T8	UNATTENDED TRANSM	345.00	230.00	13.20
12	TWEEDY-T1	UNATTENDED DISTRIB	115.00	13.20	
13	TYLER-T1W,T1E,T1	UNATTENDED DISTRIB	13.20	2.40	
14	UNITED SALT-T1	UNATTENDED DISTRIB	69.00	12.50	
15	URTON-T1	UNATTENDED DISTRIB	115.00	13.20	
16	VAN BUREN-T1	UNATTENDED DISTRIB	69.00	13.20	
17	VAN BUREN-T2	UNATTENDED DISTRIB	69.00	13.20	
18	VEGA-T1	UNATTENDED DISTRIB	69.00	13.20	
19	VICKERS-T1	UNATTENDED DISTRIB	69.00	23.00	
20	WADE-T1	UNATTENDED DISTRIB	115.00	13.20	
21	WARD-T1	UNATTENDED DISTRIB	115.00	12.50	
22	WASSON-T1	UNATTENDED DISTRIB	69.00	2.40	
23	WATERFIELD-T1	UNATTENDED DISTRIB	69.00	13.20	
24	WAVERLY-T1	UNATTENDED DISTRIB	23.00	4.16	
25	WEATHERLY-T1	UNATTENDED DISTRIB	69.00	13.80	
26	WELLMAN-T1	UNATTENDED DISTRIB	69.00	12.50	
27	WEST BENDER-T1	UNATTENDED DISTRIB	115.00	7.20	
28	WHEELER COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
29	WHERRY HOUSING-T1	UNATTENDED DISTRIB	69.00	12.50	
30	WHITAKER-T1	UNATTENDED DISTRIB	115.00	13.80	
31	WHITE CITY-T1	UNATTENDED DISTRIB	7.20	2.40	
32	WHITEFACE-T1	UNATTENDED DISTRIB	69.00	12.50	
33	WHITEHEAD-T1	UNATTENDED DISTRIB	69.00	4.16	
34	WHITHARREL-T1	UNATTENDED DISTRIB	69.00	4.16	
35	WHITTEN-T1	UNATTENDED DISTRIB	115.00	12.50	
36	WILDORADO-T1	UNATTENDED DISTRIB	69.00	12.50	
37	WILLS OIL-T1E, T1	UNATTENDED DISTRIB	69.00	7.20	
38	WILLS OIL-T1W	UNATTENDED DISTRIB	69.00	12.50	
39	WILSON-T1	UNATTENDED DISTRIB	23.00	2.40	
40	WIPP-T1	UNATTENDED DISTRIB	115.00	13.80	

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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.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WIPP-T2	UNATTENDED DISTRIB	115.00	13.80	
2	WOLFFORTH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
3	WOODDRAW-T1	UNATTENDED DISTRIB	115.00	13.20	
4	XIT-T1	UNATTENDED TRANSM	230.00	115.00	13.20
5	YANCY-T1	UNATTENDED DISTRIB	69.00	2.40	
6	YOAKUM COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
7	YOAKUM COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
8	ZAVALLA-T1	UNATTENDED DISTRIB	69.00	12.50	
9	ZIA-T1	UNATTENDED DISTRIB	115.00	13.20	
10	529				
11					
12	Count TTL Transformer Banks	529			
13	Count TTL Transformers In Service	602			
14	TTL MVA In Service	27,432			
15	Count TTL Substations with Transformers	394			
16	Count TTL Substations without Transformers	65			
17	Count TTL Substations	459			
18	Count TTL Spares	39			
19					
20					
21	Spare Transformers				
22	10 MVA MOBILE-T1	N/A	69.00	13.20	
23	16 MVA MOBILE-T1	N/A	69.00	12.50	
24	20 MVA NEW MOBILE-T1	N/A	115.00	25.00	
25	20 MVA OLD MOBILE-T1	N/A	115.00	25.00	
26	3 MVA MOBILE-T1	N/A	25.00	12.50	
27	56 MVA MOBILE	N/A	115.00	69.00	13.20
28	Booker-S490008	N/A	69.00	35.00	
29	Chaves-	N/A	230.00	115.00	
30	Clovis Yard-	N/A	69.00	5.00	
31	Clovis Yard-SHT-5301-0101	N/A	69.00	5.00	
32	EAST PLANT-201741	N/A	115.00	5.00	
33	EAST PLANT-207971	N/A	69.00	35.00	
34	EAST PLANT-2720511	N/A	35.00	13.00	
35	EAST PLANT-3461025	N/A	35.00	13.00	
36	EAST PLANT-58224618211	N/A	115.00	14.00	
37	EAST PLANT-6151201	N/A	69.00	13.00	
38	EAST PLANT-6352677	N/A	14.00	2.50	
39	EAST PLANT-7018874	N/A	13.00	5.00	
40	EAST PLANT-86201	N/A	35.00	13.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EAST PLANT-9405401326	N/A	69.00	35.00	
2	EAST PLANT-C4234411	N/A	69.00	5.00	
3	EAST PLANT-C500502	N/A	69.00	25.00	
4	EAST PLANT-M16218813	N/A	69.00	13.00	
5	FOLLETT-3330738	N/A	35.00	7.50	
6	Harrington Poleyard-5352PH099	N/A	230.00	115.00	13.00
7	Harrington Poleyard-8727009	N/A	345.00	230.00	
8	Harrington Poleyard-E4468	N/A	115.00	69.00	13.00
9	Harrington Poleyard-E4469	N/A	115.00	69.00	13.00
10	Hobbs Gen-LLL5856-2	N/A	230.00	138.00	13.00
11	Navajo #4 Yard- B313935	N/A	69.00	5.00	
12	North Subs Opns-	N/A	35.00	5.00	
13	North Subs Opns-	N/A	25.00	5.00	
14	North Subs Opns-	N/A	14.00	5.00	
15	Plainview City-8976856	N/A	69.00	2.50	
16	RIVERVIEW PLANT-1699300	N/A	14.00	2.50	
17	RIVERVIEW PLANT-26038-1	N/A	13.00	2.50	
18	RIVERVIEW PLANT-921156	N/A	35.00	13.00	
19	RIVERVIEW PLANT-C-859906	N/A	35.00	2.50	
20	Sage Brush-13951	N/A	115.00	25.00	
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1	3					1
37	1					2
3	1					3
3	1					4
3	1					5
14	1					6
13	1					7
11	1					8
3	1					9
11	1					10
22	1					11
252	1					12
8	1					13
4	1					14
3	1					15
168	1					16
168	1					17
2	1					18
28	1					19
28	1					20
11	1					21
5	1					22
13	1					23
14	1					24
40	1					25
40	1					26
1	3					27
40	1					28
3	1					29
1	1					30
1	1					31
1	1					32
50	1					33
50	1					34
1	1					35
3	1					36
50	1					37
50	1					38
17	1					39
75	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
75	1					1
3	1					2
224	1					3
4	1					4
1	1					5
	1					6
8	1					7
4	1					8
5	1					9
4	1					10
28	1					11
84	1					12
84	1					13
84	1					14
28	1					15
3	1					16
6	1					17
13	1					18
13	1					19
11	1					20
150	1					21
28	1					22
14	1					23
7	1					24
11	1					25
28	1					26
28	1					27
13	1					28
	1					29
28	1					30
28	1					31
28	1					32
168	1					33
40	1					34
20	1					35
	3					36
4	1					37
40	1					38
40	1					39
20	1					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
13	1					1
75	1					2
75	1					3
1	3					4
25	1					5
28	1					6
28	1					7
250	1					8
252	1					9
44	1					10
28	1					11
110	1					12
28	1					13
28	1					14
11	1					15
1	3					16
6	1					17
28	1					18
25	1					19
6	1					20
28	1					21
22	1					22
14	1					23
28	1					24
40	1					25
40	1					26
	3					27
22	1					28
14	1					29
5	1					30
14	1					31
25	1					32
75	1					33
19	1					34
84	1					35
8	1					36
4	1					37
25	1					38
5	1					39
5	1					40

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SUBSTATIONS (Continued)

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6	1					1
84	1					2
40	1					3
6	1					4
20	1					5
	1					6
20	1					7
44	1					8
40	1					9
5	1					10
40	1					11
22	1					12
9	1					13
40	1					14
10	1					15
5	1					16
	3					17
9	1					18
250	1					19
168	1					20
8	1					21
13	1					22
50	1					23
50	1					24
4	1					25
4	1					26
67	1					27
1	3					28
20	1					29
14	1					30
22	1					31
22	1					32
20	1					33
50	1					34
22	1					35
20	1					36
28	1					37
6	1					38
4	1					39
6	1					40

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3	1					1
6	1					2
40	1					3
28	1					4
252	1					5
84	1					6
84	1					7
2	3					8
22	1					9
168	1					10
100	1					11
560	1					12
250	1					13
13	1					14
	3					15
8	1					16
28	1					17
28	1					18
20	1					19
25	1					20
28	1					21
13	1					22
11	1					23
28	1					24
3	1					25
28	1					26
11	1					27
84	1					28
75	1					29
1	3					30
1	3					31
1	1					32
6	1					33
1	2					34
3	1					35
20	1					36
25	1					37
40	1					38
40	1					39
6	1					40

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14	1					1
5	1					2
1	3					3
84	1					4
84	1					5
250	1					6
250	1					7
75	1					8
2	1					9
4	1					10
2	1					11
4	1					12
15	1					13
40	1					14
40	1					15
6	1					16
84	1					17
84	1					18
1	3					19
14	1					20
28	1					21
13	1					22
20	1					23
84	1					24
84	1					25
40	1					26
40	1					27
17	1					28
28	1					29
2	3					30
47	1					31
560	1					32
250	1					33
560	1					34
150	1					35
200	1					36
28	1					37
22	1					38
28	1					39
22	1					40

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SUBSTATIONS (Continued)

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22	1					1
2	3					2
84	1					3
84	1					4
28	1					5
14	1					6
40	1					7
84	1					8
75	1					9
150	1					10
150	1					11
272	1					12
273	1					13
2	1					14
7	1					15
20	1					16
6	1					17
20	1					18
5	1					19
2	3					20
14	1					21
75	1					22
84	1					23
20	1					24
1	3					25
84	1					26
22	1					27
14	1					28
56	1					29
10	1					30
252	1					31
75	1					32
75	1					33
84	1					34
3	1					35
28	1					36
28	1					37
14	1					38
13	1					39
50	1					40

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SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
22	1					2
2	3					3
2	3					4
22	1					5
28	1					6
7	1					7
1	1					8
8	1					9
1	1					10
1	2					11
28	1					12
3	1					13
14	1					14
3	3					15
3	1					16
2	1					17
28	1					18
150	1					19
84	1					20
84	1					21
252	1					22
84	1					23
250	1					24
40	1					25
27	1					26
14	1					27
20	1					28
3	1					29
14	1					30
13	1					31
6	1					32
25	1					33
13	1					34
11	1					35
25	1					36
9	1					37
5	1					38
4	1					39
14	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
5	1					2
10	1					3
28	1					4
225	1					5
17	1					6
5	1					7
10	1					8
14	1					9
14	1					10
50	1					11
250	1					12
8	1					13
22	1					14
22	1					15
22	1					16
22	1					17
11	1					18
250	1					19
250	1					20
150	1					21
11	1					22
22	1					23
28	1					24
28	1					25
84	1					26
225	1					27
168	1					28
28	1					29
29	1					30
8	1					31
4	1					32
3	3					33
3	3					34
28	1					35
25	1					36
25	1					37
22	1					38
8	1					39
8	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
84	1					1
22	1					2
5	1					3
168	1					4
28	1					5
27	1					6
13	1					7
12	1					8
6	3					9
3	1					10
3	1					11
28	1					12
1	3					13
1	3					14
22	1					15
14	1					16
14	1					17
22	1					18
22	1					19
252	1					20
6	1					21
250	1					22
8	1					23
14	1					24
7	1					25
84	1					26
84	1					27
8	1					28
13	1					29
250	1					30
84	1					31
84	1					32
500	1					33
252	1					34
250	1					35
28	1					36
25	1					37
28	1					38
225	1					39
28	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1					1
25	1					2
3	3					3
225	1					4
250	1					5
6	1					6
8	1					7
8	1					8
25	1					9
40	1					10
250	1					11
448	1					12
6	1					13
250	1					14
252	1					15
28	1					16
28	1					17
40	1					18
40	1					19
	3					20
14	1					21
12	1					22
25	1					23
50	1					24
22	1					25
3	3					26
28	1					27
75	1					28
3	1					29
150	1					30
150	1					31
28	1					32
44	1					33
150	1					34
	3					35
2	3					36
13	1					37
13	1					38
20	1					39
2	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k)	Line No.
14	1					1
4	1					2
4	1					3
5	1					4
4	1					5
37	1					6
84	1					7
25	1					8
28	1					9
1	3					10
28	1					11
2	3					12
11	1					13
11	1					14
84	1					15
13	1					16
9	1					17
28	1					18
8	1					19
6	1					20
28	1					21
3	1					22
4	1					23
5	1					24
45	1					25
45	1					26
100	1					27
3	3					28
25	1					29
28	1					30
250	1					31
3	1					32
7	1					33
14	1					34
7	1					35
84	1					36
84	1					37
20	1					38
9	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
6	1					1
560	1					2
560	1					3
84	1					4
252	1					5
84	1					6
84	1					7
13	1					8
90	1					9
225	1					10
560	1					11
22	1					12
2	3					13
1	1					14
22	1					15
25	1					16
25	1					17
14	1					18
14	1					19
7	1					20
5	1					21
2	1					22
8	1					23
4	1					24
14	1					25
5	1					26
22	1					27
250	1					28
4	1					29
25	1					30
3	1					31
14	1					32
4	1					33
3	1					34
13	1					35
13	1					36
1	2					37
1	1					38
1	1					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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22	1					1
168	1					2
28	1					3
250	1					4
2	1					5
150	1					6
150	1					7
13	1					8
13	1					9
27432	602					10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
10		1				22
16		1				23
20		1				24
20		1				25
3		1				26
56		1				27
8		1				28
150		1				29
4		1				30
7		1				31
6		1				32
20		1				33
11		1				34
5		1				35
20		1				36
6		1				37
3		1				38
4		1				39
1		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
6		1				1
8		1				2
6		1				3
28		1				4
		1				5
250		1				6
560		1				7
84		1				8
84		1				9
150		1				10
5		1				11
4		1				12
4		1				13
4		1				14
1		1				15
2		1				16
2		1				17
3		1				18
2		1				19
50		1				20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Services provided by Xcel Energy Services, Inc.	Xcel Energy Services Inc.	See Footnote	
3				
4				
5				
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services	233	-595,000,000
7	Repayments from Utility Money Pool Arrangement	Xcel energy Services	145	-285,000,000
8	Capital Contributions from Parent	Xcel Energy, Inc.	207	-336,587,000
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23	Investment in Utility Money Pool Arrangement	Xcel Energy Services	145	350,000,000
24	Repayment under Utility Money Pool Arrangement	Xcel Energy Services	233	595,000,000
25	Dividends on Common Stock	Xcel Energy, Inc.	438	130,776,625
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column: c

Service Function Group	Updated FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	113,071
	181-190-Deferred Debits	2,460
	408-409-Taxes	639,353
	417-421-Other Income	(48,524)
	426.1-426.5-Other Income Deductions	4,927
	427-432-Interest Charges	1,695
	500-514-Steam Power Generation	275,456
	546-557-Other Power Generation	124,695
	560-573-Transmission Expenses	1,252
	580-598-Distribution Expenses	468
	920-935-Administrative and General Expense	9,459,186
Accounting, Financial Reporting & Taxes Total		10,574,039
Aviation Services	408-409-Taxes	9,486
	426.1-426.5-Other Income Deductions	141
	920-935-Administrative and General Expense	797,785
Aviation Services Total		807,412
Business Systems	107-CWIP	23,980,542
	108-Accum Dep	37,934
	408-409-Taxes	566,602
	426.1-426.5-Other Income Deductions	(2,324)
	500-514-Steam Power Generation	881,173
	546-557-Other Power Generation	98,451
	560-573-Transmission Expenses	2,701,136
	580-598-Distribution Expenses	690,875
	901-905-Customer Accounts Expenses	1,535,346
	908-910-Customer Service and Informational Expenses	921
	911-916-Sales Expense	424

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Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

	920-935-Administrative and General Expense	34,821,592
Business Systems Total		65,312,672
Claims Services	408-409-Taxes	12,813
	920-935-Administrative and General Expense	269,274
Claims Services Total		282,087
Corporate Communications	181-190-Deferred Debits	286,759
	408-409-Taxes	48,940
	426.1-426.5-Other Income Deductions	1,641,829
	546-557-Other Power Generation	436,508
	560-573-Transmission Expenses	248
	580-598-Distribution Expenses	(1,212)
	908-910-Customer Service and Informational Expenses	108,803
	920-935-Administrative and General Expense	1,018,678
Corporate Communications Total		3,540,553
Corporate Strategy & Business Development	408-409-Taxes	22,775
	426.1-426.5-Other Income Deductions	6,248
	908-910-Customer Service and Informational Expenses	190
	920-935-Administrative and General Expense	421,052
Corporate Strategy & Business Development Total		450,265
Customer Service	107-CWIP	26
	181-190-Deferred Debits	122,068
	408-409-Taxes	171,521
	426.1-426.5-Other Income Deductions	1,049
	901-905-Customer Accounts Expenses	3,906,734
	908-910-Customer Service and Informational Expenses	84,610
	920-935-Administrative and General Expense	700,604
Customer Service Total		4,986,612
Employee Communications	408-409-Taxes	4,983
	426.1-426.5-Other Income Deductions	3

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

	920-935-Administrative and General Expense	117,260
Employee Communications Total		122,246
Energy Delivery - Engineering/Design	107-CWIP	18,486,483
	108-Accum Dep	695,478
	408-409-Taxes	657,882
	426.1-426.5-Other Income Deductions	11,607
	500-514-Steam Power Generation	30
	546-557-Other Power Generation	1
	560-573-Transmission Expenses	4,491,951
	580-598-Distribution Expenses	249,482
	901-905-Customer Accounts Expenses	60
	920-935-Administrative and General Expense	2,367,386
Energy Delivery - Engineering/Design Total		26,960,360
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	726,971
	108-Accum Dep	1,329
	130-176-Current and Accrued Assets	(1,352)
	408-409-Taxes	51,283
	426.1-426.5-Other Income Deductions	2,491
	560-573-Transmission Expenses	1,467,900
	580-598-Distribution Expenses	2,374,535
	901-905-Customer Accounts Expenses	140
	908-910-Customer Service and Informational Expenses	240
	920-935-Administrative and General Expense	557,331
Energy Delivery Construction, Operations & Maintenance (COM) Total		5,180,868
Energy Markets - Fuel Procurement	107-CWIP	6,092
	408-409-Taxes	45,153
	426.1-426.5-Other Income Deductions	12
	500-514-Steam Power Generation	697,159

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

	546-557-Other Power Generation	48,726
	560-573-Transmission Expenses	3,284
	575.1-575.8-Regional Market Expenses	938
	920-935-Administrative and General Expense	250,529
Energy Markets - Fuel Procurement Total		1,051,893
Energy Markets Regulated Trading & Marketing	107-CWIP	16
	408-409-Taxes	217,422
	426.1-426.5-Other Income Deductions	20,116
	500-514-Steam Power Generation	446
	546-557-Other Power Generation	2,356,234
	560-573-Transmission Expenses	92,034
	575.1-575.8-Regional Market Expenses	534,570
	908-910-Customer Service and Informational Expenses	13,576
	920-935-Administrative and General Expense	1,329,651
Energy Markets Regulated Trading & Marketing Total		4,564,065
Energy Supply Business Resources	107-CWIP	378,376
	108-Accum Dep	65,614
	408-409-Taxes	407,666
	426.1-426.5-Other Income Deductions	3,423
	500-514-Steam Power Generation	7,295,783
	546-557-Other Power Generation	314,569
	560-573-Transmission Expenses	8,428
	580-598-Distribution Expenses	37,837
	920-935-Administrative and General Expense	2,453,327
Energy Supply Business Resources Total		10,965,023
Energy Supply Engineering & Environmental	107-CWIP	4,425,766
	108-Accum Dep	846,303
	408-409-Taxes	195,286
	426.1-426.5-Other Income Deductions	213

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Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

	500-514-Steam Power Generation	880,777
	546-557-Other Power Generation	75,631
	560-573-Transmission Expenses	26,342
	580-598-Distribution Expenses	12,218
	920-935-Administrative and General Expense	1,402,835
Energy Supply Engineering & Environmental Total		7,865,371
Executive Management Services	107-CWIP	350,341
	408-409-Taxes	42,539
	426.1-426.5-Other Income Deductions	94,938
	500-514-Steam Power Generation	(10,299)
	546-557-Other Power Generation	(7,231)
	560-573-Transmission Expenses	(28,941)
	580-598-Distribution Expenses	(736)
	920-935-Administrative and General Expense	2,018,478
Executive Management Services Total		2,459,089
Facilities & Real Estate	107-CWIP	192,565
	108-Accum Dep	10,058
	408-409-Taxes	52,552
	426.1-426.5-Other Income Deductions	25,164
	500-514-Steam Power Generation	4,843,749
	546-557-Other Power Generation	395,474
	560-573-Transmission Expenses	1,645,629
	575.1-575.8-Regional Market Expenses	26,053
	580-598-Distribution Expenses	1,558,923
	920-935-Administrative and General Expense	6,758,492
Facilities & Real Estate Total		15,508,659
Finance & Treasury	107-CWIP	406,400
	108-Accum Dep	24,573
	181-190-Deferred Debits	24,015
	408-409-Taxes	97,800
	417-421-Other Income	(235,506)
	426.1-426.5-Other Income Deductions	24,177
	427-432-Interest Charges	1,071,157
	546-557-Other Power Generation	165,449
	560-573-Transmission Expenses	(123,858)
	580-598-Distribution Expenses	(44,151)
	901-905-Customer Accounts Expenses	287
	908-910-Customer Service and Informational Expenses	987

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

	920-935-Administrative and General Expense	5,454,128
Finance & Treasury Total		6,865,458
Fleet	107-CWIP	681,402
	108-Accum Dep	1,043
	500-514-Steam Power Generation	14,780
	546-557-Other Power Generation	148
	560-573-Transmission Expenses	21,503
	580-598-Distribution Expenses	453,209
	901-905-Customer Accounts Expenses	47,770
	908-910-Customer Service and Informational Expenses	5,330
	911-916-Sales Expense	344
	920-935-Administrative and General Expense	18,341
Fleet Total		1,243,870
Government Affairs	408-409-Taxes	13,063
	426.1-426.5-Other Income Deductions	160,664
	920-935-Administrative and General Expense	234,660
Government Affairs Total		408,387
Human Resources	107-CWIP	10,353
	108-Accum Dep	11,773
	181-190-Deferred Debits	240,391
	231-245-Current and Accrued Liabilities	3,927,655
	408-409-Taxes	218,160
	426.1-426.5-Other Income Deductions	22,081
	500-514-Steam Power Generation	(167,816)
	560-573-Transmission Expenses	102,885
	580-598-Distribution Expenses	472,871
	908-910-Customer Service and Informational Expenses	33,359
	920-935-Administrative and General Expense	6,724,199
Human Resources Total		11,595,911
Internal Audit	408-409-Taxes	18,135
	426.1-426.5-Other Income Deductions	27

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

	920-935-Administrative and General Expense	388,593
Internal Audit Total		406,755
Investor Relations	408-409-Taxes	5,612
	426.1-426.5-Other Income Deductions	376
	920-935-Administrative and General Expense	327,246
Investor Relations Total		333,234
Legal	107-CWIP	21,531
	108-Accum Dep	86
	408-409-Taxes	119,403
	426.1-426.5-Other Income Deductions	7,132
	560-573-Transmission Expenses	49,791
	920-935-Administrative and General Expense	2,571,236
Legal Total		2,769,179
Marketing & Sales	181-190-Deferred Debits	1,088,516
	408-409-Taxes	32,532
	426.1-426.5-Other Income Deductions	3,245
	901-905-Customer Accounts Expenses	18
	908-910-Customer Service and Informational Expenses	192,051
	920-935-Administrative and General Expense	2,000,965
Marketing & Sales Total		3,317,327
Payment & Reporting	107-CWIP	731
	408-409-Taxes	9,914
	920-935-Administrative and General Expense	322,148
Payment & Reporting Total		332,793
Payroll	107-CWIP	(18,097)
	108-Accum Dep	(1,079)
	181-190-Deferred Debits	(1,044)
	408-409-Taxes	16,812
	426.1-426.5-Other Income Deductions	(423)
	560-573-Transmission Expenses	5,644

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

	580-598-Distribution Expenses	1,814
	920-935-Administrative and General Expense	248,290
Payroll Total		251,917
Rates & Regulation	181-190-Deferred Debits	1,831,526
	408-409-Taxes	95,849
	426.1-426.5-Other Income Deductions	11
	546-557-Other Power Generation	1,660
	560-573-Transmission Expenses	1,823
	580-598-Distribution Expenses	(10,525)
	908-910-Customer Service and Informational Expenses	10,001
	920-935-Administrative and General Expense	1,921,886
Rates & Regulation Total		3,852,231
Receipts Processing	408-409-Taxes	16,443
	426.1-426.5-Other Income Deductions	983
	901-905-Customer Accounts Expenses	82,866
	920-935-Administrative and General Expense	131,404
Receipts Processing Total		231,696
Supply Chain	107-CWIP	2,446,101
	108-Accum Dep	19,812
	181-190-Deferred Debits	4,853
	231-245-Current and Accrued Liabilities	(2,060)
	408-409-Taxes	4,609
	426.1-426.5-Other Income Deductions	538
	500-514-Steam Power Generation	162,755
	546-557-Other Power Generation	12,455
	560-573-Transmission Expenses	28,937
	575.1-575.8-Regional Market Expenses	85
	580-598-Distribution Expenses	81,835
	901-905-Customer Accounts Expenses	7,861
	908-910-Customer Service and Informational Expenses	1,389
	920-935-Administrative and General Expense	69,274

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Supply Chain Total	2,838,444
Grand Total	195,078,416

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INDEPENDENT ACCOUNTANTS' REVIEW REPORT

To the Board of Directors of
Southwestern Public Service Company
Amarillo, Texas

We have reviewed the historical dollar amounts included in rate 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"), included in the Rate Filing Package of Southwestern Public Service Company ("SPS") as of and for the 12 months ended March 31, 2019, submitted pursuant to 530 of the New Mexico Public Regulation Commission ("NMPRC"). SPS' management is responsible for the Schedules. Our responsibility is to express a conclusion on the Schedules 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 Schedules in order for them to be in accordance with the criteria. A review is substantially less in scope than an examination, the objective of which is to obtain reasonable assurance about whether the Schedules are in accordance with the criteria, 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.

Our review procedures did not extend to adjustments, estimated amounts, non-accounting, or non-financial information included in the Schedules, 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 order for them to be in accordance with Rule 530 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 Rule 530, and is not intended to be, and should not be, used by anyone other than the specified parties.

Deloitte & Touche LLP

June 28, 2019