Section 1: 8-K (8-K)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) Feb. 7, 2018

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
001-3034	XCEL ENERGY INC. (a Minnesota corporation) 414 Nicollet Mall Minneapolis, Minnesota 55401 (612) 330-5500	41-0448030
000-31387	NORTHERN STATES POWER COMPANY (a Minnesota corporation) 414 Nicollet Mall Minneapolis, Minnesota 55401 (612) 330-5500	41-1967505
001-03140	NORTHERN STATES POWER COMPANY (a Wisconsin corporation) 1414 W. Hamilton Avenue Eau Claire, Wisconsin 54701 (715) 737-2625	39-0508315
001-3280	PUBLIC SERVICE COMPANY OF COLORADO (a Colorado corporation) 1800 Larimer, Suite 1100 Denver, Colorado 80202 (303) 571-7511	84-0296600
001-03789	SOUTHWESTERN PUBLIC SERVICE COMPANY (a New Mexico corporation) 790 South Buchanan Street Amarillo, Texas 79101 (303) 571-7511	75-0575400

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (17 CFR §230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (17 CFR §240.12b-2).
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. £

Item 2.02. Results of Operations and Financial Condition

On Feb. 7, 2018, Xcel Energy released earnings results for 2017.

See additional information in the Earnings Release furnished as exhibit 99.01.

Item 9.01. Financial Statements and Exhibits

(d) Exhibits

Exhibit No.	**Description**
99.01	Earnings Release of Xcel Energy dated Feb. 7, 2018.

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 hereunto duly authorized.

Feb. 7, 2018

Xcel Energy Inc.
(a Minnesota corporation)
Northern States Power Company
(a Minnesota corporation)
Northern States Power Company
(a Wisconsin corporation)
Public Service Company of Colorado
(a Colorado corporation)
Southwestern Public Service Company
(a New Mexico corporation)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer

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Section 2: EX-99.01 (EXHIBIT 99.01)

Exhibit 99.01

Feb. 7, 2018

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
2017 YEAR END EARNINGS REPORT

- GAAP 2017 earnings per share were $2.25 compared with $2.21 per share in 2016.
- Ongoing 2017 earnings per share were $2.30 compared with $2.21 per share in 2016.
- Enactment of the Tax Cuts and Jobs Act had a negative impact of $0.05 per share in 2017.
- Xcel Energy reaffirms 2018 GAAP and ongoing earnings guidance of $2.37 to $2.47 per share.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2017 GAAP earnings of $1,148 million, or $2.25 per share and ongoing earnings of $1,171 million or $2.30 per share, compared with GAAP and ongoing earnings of $1,123 million, or $2.21 per share in 2016.

GAAP and ongoing earnings were higher as a result of increased electric and natural gas margins to recover infrastructure investments, reduced operating and maintenance expenses, a lower effective tax rate and higher allowance for funds used during construction. These positive factors were partially offset by increased depreciation expense, interest charges and property taxes. GAAP earnings for 2017 also included the negative impact of the recently enacted Tax Cuts and Jobs Act (TCJA).

“We once again delivered on our objectives in 2017, achieved our earnings and dividend targets, while keeping average bills to our customers flat-to-down for the fourth consecutive year,” said Ben Fowke, chairman, president and CEO of Xcel Energy. “We continue to execute our Steel-for-Fuel strategy by advancing wind projects that deliver great value to customers. We anticipate making further progress on our strategy in 2018 with the proposed Colorado Energy Plan whose preliminary bid responses have proven to be very promising for our customers.”

“Looking ahead,” Fowke continued, “we plan to work with regulators to bring the benefits of tax reform to our customers as we continue to drive a transition to cleaner energy and pursue investment opportunities in advanced grid technologies and continued electrification. These advancements will allow us to offer more innovative services to customers while continuing to deliver on our EPS and dividend growth objectives.”

Earnings Adjusted for Certain Items (Ongoing Earnings)

The following table provides a reconciliation of ongoing earnings per share (EPS) to generally accepted accounting principles (GAAP) EPS:

Diluted Earnings Per Share	Three Months Ended Dec. 31 2017	Three Months Ended Dec. 31 2016	Twelve Months Ended Dec. 31 2017	Twelve Months Ended Dec. 31 2016
GAAP diluted EPS	**$ 0.37**	**$ 0.45**	**$ 2.25**	**$ 2.21**
Estimated impact of the TCJA [a]	0.05	—	0.05	—
Ongoing diluted EPS	**$ 0.42**	**$ 0.45**	**$ 2.30**	**$ 2.21**

(a) See Notes 5 and 7.

At 9:00 a.m. CST today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial in 5 to 10 minutes prior to the start and follow the operator's instructions.

US Dial-In:	(888) 203-7667
International Dial-In:	(719) 325-2109
Conference ID:	6701954

The conference call also will be simultaneously broadcast and archived on Xcel Energy's website at www.xcelenergy.com. To access the presentation, click on Investor Relations. If you are unable to participate in the live event, the call will be available for replay from 1:00 p.m. CST on Feb. 7 through 11:00 p.m. CST on Feb. 9.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	6701954

Except for the historical statements contained in this release, the matters discussed herein, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including our 2018 EPS guidance, the TCJA's impact to customers, rate base, valuation of deferred tax assets and liabilities, cash flow, credit metrics, long-term earnings per share and dividend growth rate, and potential regulatory options, 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 in Xcel Energy's Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2016 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 Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) 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 Xcel Energy 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 Xcel Energy; 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.

For more information, contact:

Paul Johnson, Vice President, Investor Relations	(612) 215-4535
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For news media inquiries only, please call Xcel Energy Media Relations	(612) 215-5300
Xcel Energy internet address: www.xcelenergy.com	

This information is not given in connection with any sale, offer for sale or offer to buy any security.

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

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
	2017	2016	2017	2016
Operating revenues				
Electric	$ 2,256	$ 2,291	$ 9,676	$ 9,500
Natural gas	520	485	1,650	1,531
Other	20	19	78	76
Total operating revenues	2,796	2,795	11,404	11,107
Operating expenses				
Electric fuel and purchased power	906	963	3,757	3,718
Cost of natural gas sold and transported	279	263	823	733
Cost of sales — other	9	11	34	36
Operating and maintenance expenses	597	562	2,303	2,326
Conservation and demand side management program expenses	67	67	273	245
Depreciation and amortization	378	332	1,479	1,303
Taxes (other than income taxes)	134	131	545	532
Total operating expenses	2,370	2,329	9,214	8,893
Operating income	426	466	2,190	2,214
Other income, net	9	1	23	8
Equity earnings of unconsolidated subsidiaries	7	10	30	42
Allowance for funds used during construction — equity	21	15	75	60
Interest charges and financing costs				
Interest charges — includes other financing costs of $6, $6, $24, and $25, respectively	165	162	663	647
Allowance for funds used during construction — debt	(9)	(7)	(35)	(27)
Total interest charges and financing costs	156	155	628	620
Income before income taxes	307	337	1,690	1,704
Income taxes	118	110	542	581
Net income	$ 189	$ 227	$ 1,148	$ 1,123
Weighted average common shares outstanding:				
Basic	509	509	509	509
Diluted	509	509	509	509
Earnings per average common share:				
Basic	$ 0.37	$ 0.45	$ 2.26	$ 2.21
Diluted	0.37	0.45	2.25	2.21
Cash dividends declared per common share	$ 0.36	$ 0.34	$ 1.44	$ 1.36

Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary as well as the return on equity (ROE) of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary, but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS and ongoing ROE for Xcel Energy and by subsidiary are financial measures not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing ROE is calculated by dividing the net income or loss attributable to the controlling interest of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average common stockholders' or stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. These non-GAAP financial measures should not be considered as alternatives to measures calculated and reported in accordance with GAAP.

Note 1. Earnings Per Share Summary

The following tables summarize diluted EPS for Xcel Energy:

	Three Months Ended Dec. 31			
	2017			2016
Diluted Earnings (Loss) Per Share	**GAAP Diluted EPS**	**Impact of TCJA [a]**	**Ongoing Diluted EPS**	**GAAP and Ongoing Diluted EPS**
NSP-Minnesota	$ 0.15	$ 0.05	$ 0.20	$ 0.21
Public Service Company of Colorado (PSCo)	0.19	(0.03)	0.16	0.17
Southwestern Public Service Company (SPS)	0.06	(0.01)	0.05	0.06
NSP-Wisconsin	0.04	—	0.04	0.03
Equity earnings of unconsolidated subsidiaries [b]	0.05	(0.04)	0.01	0.01
Regulated utility [c]	$ 0.49	$ (0.03)	$ 0.46	$ 0.48
Xcel Energy Inc. and other	(0.12)	0.07	(0.05)	(0.04)
Total [c]	$ 0.37	$ 0.05	$ 0.42	$ 0.45

	Twelve Months Ended Dec. 31			
	2017			2016
Diluted Earnings (Loss) Per Share	**GAAP Diluted EPS**	**Impact of TCJA [a]**	**Ongoing Diluted EPS**	**GAAP and Ongoing Diluted EPS**
NSP-Minnesota	$ 0.96	$ 0.05	$ 1.01	$ 0.96
PSCo	0.97	(0.03)	0.94	0.91
SPS	0.31	(0.01)	0.30	0.30
NSP-Wisconsin	0.16	—	0.16	0.14
Equity earnings of unconsolidated subsidiaries [b]	0.07	(0.04)	0.03	0.05
Regulated utility [c]	$ 2.47	$ (0.03)	$ 2.45	$ 2.35
Xcel Energy Inc. and other	(0.22)	0.07	(0.15)	(0.15)
Total [c]	$ 2.25	$ 0.05	$ 2.30	$ 2.21

(a) See Notes 5 and 7.
(b) Includes income taxes.
(c) Amounts may not add due to rounding.

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 effective tax rate (ETR) and reduced operating and maintenance (O&M) expenses. The decrease in the ETR is largely driven by resolution of Internal Revenue Service appeals/audits and an increase in wind production tax credits (PTCs), which are flowed back to customers and reduce electric margin. Lower O&M expenses primarily relate to reduced expenses for nuclear refueling outages and overhauls at generation facilities. 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.

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 allowance for funds used during construction (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.

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 our WYCO Development, LLC subsidiary, which develops and leases natural gas pipelines, storage and compression facilities.

The following table summarizes significant components contributing to the changes in 2017 EPS compared with the same period in 2016:

Diluted Earnings (Loss) Per Share	**Three Months Ended Dec. 31**	**Twelve Months Ended Dec. 31**
GAAP and ongoing diluted EPS — 2016	**$ 0.45**	**$ 2.21**
Components of change — 2017 vs. 2016		
Higher electric margins [(a)]	0.03	0.16
(Higher) lower ETR [(b)]	(0.04)	0.07
Higher natural gas margins	0.02	0.03
Higher AFUDC — equity	0.01	0.03
(Higher) lower O&M expenses	(0.04)	0.03
Higher depreciation and amortization	(0.05)	(0.21)
Higher conservation and demand side management (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	(0.01)	0.02
GAAP diluted EPS — 2017	**0.37**	**2.25**
Impact of the TCJA [(d)]	0.05	0.05
Ongoing diluted EPS — 2017	**$ 0.42**	**$ 2.30**

(a) Includes a decrease of $2 million and an increase of $23 million in revenues from conservation and DSM programs, offset by related expenses, for the three and twelve months ended Dec. 31, 2017, respectively.

(b) The ETR includes the impact of an additional $2 million and $20 million of wind PTCs for the three and twelve months ended Dec. 31, 2017, respectively, 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.

(d) See Notes 5 and 7.

The following tables summarize the ROE for Xcel Energy and its utility subsidiaries at Dec. 31:

ROE — 2017	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Operating Companies	Xcel Energy
GAAP ROE	9.05%	8.90 %	7.84 %	9.41%	8.84%	10.21%
Impact of the TCJA [(a)]	0.45	(0.24)	(0.30)	0.09	0.03	0.21
Ongoing ROE	9.50%	8.66 %	7.54 %	9.50%	8.87%	10.42%

ROE — 2016	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Operating Companies	Xcel Energy
GAAP and ongoing ROE	9.29%	8.92%	8.14%	8.63%	8.94%	10.39%

(a) See Notes 5 and 7.

Note 2. Regulated Utility Results

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy’s financial performance.

Degree-day or Temperature-Humidity Index (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. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (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 as defined above to derive the amount of demand associated with the weather impact.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are provided in the following table:

	Three Months Ended Dec. 31			Twelve Months Ended Dec. 31		
	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016
HDD	(4.0)%	(14.5)%	10.7%	(10.0)%	(13.4)%	2.6 %
CDD [(a)]	N/A	N/A	N/A	6.5	11.1	(3.5)
THI [(a)]	N/A	N/A	N/A	(11.3)	7.7	(18.5)

(a) CDD and THI have no meaningful impact on fourth quarter sales.

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with sales under normal weather conditions:

	Three Months Ended Dec. 31			Twelve Months Ended Dec. 31		
	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016
Retail electric	$ (0.004)	$ (0.016)	$ 0.012	$ (0.036)	$ 0.004	$ (0.040)
Firm natural gas	(0.003)	(0.011)	0.008	(0.023)	(0.025)	0.002
Total (excluding decoupling)	$ (0.007)	$ (0.027)	$ 0.020	$ (0.059)	$ (0.021)	$ (0.038)
Decoupling — Minnesota	(0.001)	0.007	(0.008)	0.022	(0.002)	0.024
Total (adjusted for recovery from decoupling)	$ (0.008)	$ (0.020)	$ 0.012	$ (0.037)	$ (0.023)	$ (0.014)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its utility subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2017 compared to the same period in 2016:

	Three Months Ended Dec. 31				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	2.2 %	(1.2)%	(0.6)%	4.9%	0.7%
Electric commercial and industrial	(0.7)	(2.1)	3.1	4.2	0.1
Total retail electric sales	—	(1.8)	2.4	4.4	0.3
Firm natural gas sales	19.4	4.5	N/A	26.7	10.3

	Three Months Ended Dec. 31				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	(1.4)%	(1.7)%	0.3%	(0.1)%	(1.2)%
Electric commercial and industrial	(1.2)	(1.7)	3.1	3.7	0.1
Total retail electric sales	(1.3)	(1.7)	2.6	2.6	(0.3)
Firm natural gas sales	5.2	3.8	N/A	9.6	4.6

	Twelve Months Ended Dec. 31				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	(2.1)%	(1.8)%	(3.5)%	(0.8)%	(2.1)%
Electric commercial and industrial	(1.4)	(0.1)	1.3	2.2	(0.1)
Total retail electric sales	(1.6)	(0.6)	0.2	1.3	(0.7)
Firm natural gas sales	9.3	(2.2)	N/A	11.3	2.1

	Twelve Months Ended Dec. 31				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	(0.7)%	(1.6)%	(1.2)%	0.3%	(1.0)%
Electric commercial and industrial	(1.0)	0.1	1.5	2.5	0.2
Total retail electric sales	(1.0)	(0.4)	0.9	1.8	(0.2)
Firm natural gas sales	4.7	0.6	N/A	5.7	2.2

	Twelve Months Ended Dec. 31 (Excluding Leap Day) [b]				
	NSP-Minnesota	**PSCo**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Weather-normalized - adjusted for leap day					
Electric residential [a]	(0.5)%	(1.3)%	(1.0)%	0.6%	(0.8)
Electric commercial and industrial	(0.8)	0.3	1.8	2.7	0.4
Total retail electric sales	(0.7)	(0.2)	1.1	2.1	0.1
Firm natural gas sales	5.2	1.1	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) The estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 0.3 percent for retail electric and 0.5 percent for firm natural gas for the twelve months ended.

Weather-normalized Electric Sales Growth (Decline) — Year-To-Date (Excluding Leap Day)

- NSP-Minnesota’s residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in commercial and industrial (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.
- 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.
- 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 Natural Gas Sales Growth — Year-To-Date (Excluding Leap Day)

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

Electric Margin — Electric revenues and fuel and purchased power expenses are impacted by fluctuation 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. The following table details the electric revenues and margin:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	**2017**	**2016**	**2017**	**2016**
Electric revenues	$ 2,256	$ 2,291	$ 9,676	$ 9,500
Electric fuel and purchased power	(906)	(963)	(3,757)	(3,718)
Electric margin [a]	$ 1,350	$ 1,328	$ 5,919	$ 5,782

(a) Electric margin was reduced by the flow back to customers of PTCs of approximately $27 million and $25 million for the three months ended Dec. 31, 2017 and 2016, respectively, and $134 million and $100 million for the twelve months ended Dec. 31, 2017 and 2016, respectively.

The following table summarizes the components of the changes in electric margin:

(Millions of Dollars)	Three Months Ended Dec. 31 2017 vs. 2016	Twelve Months Ended Dec. 31 2017 vs. 2016
Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin)	$ 22	$ 123
Non-fuel riders	(5)	33
Conservation and DSM revenues (offset by expenses)	(2)	23
Decoupling (weather portion — Minnesota)	(6)	18
Purchased capacity costs	10	8
Wholesale transmission revenue, net of costs	(1)	(38)
Estimated impact of weather	9	(30)
Conservation incentive	(6)	(18)
Other, net	1	18
Total increase in electric margin	$ 22	$ 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. The following table details natural gas revenues and margin:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	2017	2016	2017	2016
Natural gas revenues	$ 520	$ 485	$ 1,650	$ 1,531
Cost of natural gas sold and transported	(279)	(263)	(823)	(733)
Natural gas margin	$ 241	$ 222	$ 827	$ 798

The following table summarizes the components of the changes in natural gas margin:

(Millions of Dollars)	Three Months Ended Dec. 31 2017 vs. 2016	Twelve Months Ended Dec. 31 2017 vs. 2016
Infrastructure and integrity riders	$ 7	$ 18
Retail sales growth, excluding weather impact	4	7
Estimated impact of weather	6	1
Other, net	2	3
Total increase in natural gas margin	$ 19	$ 29

O&M Expenses — O&M expenses increased $35 million, or 6.2 percent, for the fourth quarter of 2017 and decreased $23 million, or 1.0 percent, year-to-date. The significant changes are summarized in the table below:

(Millions of Dollars)	Three Months Ended Dec. 31 2017 vs. 2016	Twelve Months Ended Dec. 31 2017 vs. 2016
Nuclear plant operations and amortization	$ (9)	$ (27)
Plant generation costs	11	(23)
Transmission costs	7	(2)
Employee benefits expense	5	17
Texas 2016 electric rate case cost deferral	8	16
Electric distribution costs	13	2
Other, net	—	(6)
Total increase (decrease) in O&M expenses	$ 35	$ (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; and
- Employee benefits expense was driven by 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 were flat for the fourth quarter of 2017 and increased $28 million, or 11.4 percent, year-to-date. The increase was due to higher customer participation in electric conservation programs and recovery rates, mostly in Minnesota. Conservation and DSM expenses, including incentives, are generally recovered in our major jurisdictions concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

Depreciation and Amortization — Depreciation and amortization increased $46 million, or 13.9 percent for the fourth quarter of 2017 and $176 million, or 13.5 percent, year-to-date. 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 $3 million, or 2.3 percent, for the fourth quarter of 2017 and $13 million, or 2.4 percent, year-to-date. The increase was primarily due to higher property taxes in Minnesota and Texas.

AFUDC, Equity and Debt — AFUDC increased $8 million for the fourth quarter of 2017 and $23 million year-to-date. The increase was primarily due to higher construction work in progress, particularly the Rush Creek wind project in Colorado.

Interest Charges — Interest charges increased $3 million, or 1.9 percent, for the fourth quarter of 2017 and $16 million, or 2.5 percent, year-to-date. 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 increased $8 million for the fourth quarter of 2017 compared with the same period in 2016, primarily driven by an estimated one-time, non-cash, income tax expense of approximately $23 million recognized upon the enactment of the TCJA (see Notes 5 and 7). The increase was partially offset by lower pretax earnings, resolution of a state audit in 2017 and increased wind PTCs. PTCs are flowed back to customers and reduce electric margin. The ETR was 38.4 percent for the fourth quarter of 2017 compared with 32.5 percent for the same period in 2016. The higher ETR in 2017 was primarily due to the adjustments referenced above. Excluding the impact of the TCJA adjustment, the ETR would have been 30.9 percent.

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 research and experimentation 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 percent for 2017 compared with 34.1 percent 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 percent for 2017.

Note 3. Xcel Energy Capital Structure, Financing and Credit Ratings

Following is the capital structure of Xcel Energy:

	As of Dec. 31, 2017		As of Dec. 31, 2016	
(Millions of Dollars)	**Capital Structure**	**Percentage of Total Capitalization**	**Capital Structure**	**Percentage of Total Capitalization**
Current portion of long-term debt	$ 457	2%	$ 255	1%
Short-term debt	814	3	392	2
Long-term debt	14,520	53	14,195	55
Total debt	15,791	58	14,842	58
Common equity	11,455	42	11,021	42
Total capitalization	$ 27,246	100%	$ 25,863	100%

Credit Facilities — As of Feb. 5, 2018, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,500	$ 844	$ 656	$ —	$ 656
PSCo	700	109	591	1	592
SPS	400	5	395	1	396
NSP-Minnesota	500	189	311	1	312
NSP-Wisconsin	150	27	123	1	124
Total	$ 3,250	$ 1,174	$ 2,076	$ 4	$ 2,080

(a) These credit facilities expire in June 2021, with the exception of Xcel Energy Inc.'s $500 million 364-day term loan agreement entered into in December 2017.

(b) Includes outstanding commercial paper and letters of credit.

Credit Ratings — Access to the capital market at reasonable terms is dependent in part on credit ratings. The following ratings reflect the views of Moody's Investors Service (Moody's), Standard & Poor's Rating Services (Standard & Poor's), and Fitch Ratings (Fitch).

The highest credit rating for debt is Aaa/AAA and the lowest investment grade rating is Baa3/BBB-. The highest rating for commercial paper is P-1/A-1/F-1 and the lowest rating is P-3/A-3/F-3. A security rating is not a recommendation to buy, sell or hold securities. Ratings are subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

As of Feb. 5, 2018, the following represents the credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries:

Credit Type	Company	Moody's	Standard & Poor's	Fitch
Senior Unsecured Debt	Xcel Energy Inc.	A3	BBB+	BBB+
	NSP-Minnesota	A2	A-	A
	NSP-Wisconsin	A2	A-	A
	PSCo	A3	A-	A
	SPS	Baa1	A-	BBB+
Senior Secured Debt	NSP-Minnesota	Aa3	A	A+
	NSP-Wisconsin	Aa3	A	A+
	PSCo	A1	A	A+
	SPS	A2	A	A-
Commercial Paper	Xcel Energy Inc.	P-2	A-2	F2
	NSP-Minnesota	P-1	A-2	F2
	NSP-Wisconsin	P-1	A-2	F2
	PSCo	P-2	A-2	F2
	SPS	P-2	A-2	F2

In January 2018, Moody's changed the ratings outlook for SPS from stable to negative due to the potential adverse impact of the TCJA on SPS' credit metrics and liquidity. All other outlooks were stable and unchanged.

Planned Financing Activity — Xcel Energy Inc. and its utility subsidiaries' 2018 debt financing plans reflect the following:

- Xcel Energy Inc. plans to issue approximately $750 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $300 million of first mortgage bonds;
- NPS-Wisconsin plans to issue approximately $200 million of first mortgage bonds;
- PSCo plans to issue approximately $750 million of first mortgage bonds; and
- SPS plans to issue approximately $350 million of first mortgage bonds.

Xcel Energy also plans to issue approximately $300 million of incremental equity in addition to the previously announced $385 million of equity to be issued through the dividend reinvestment program and benefit programs during the five-year forecast time period.

Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

Note 4. Rates and Regulation

NSP-Minnesota – Purchased Power Agreement (PPA) Terminations and Amendments — In 2017, NSP-Minnesota filed requests with the Minnesota Public Utility Commission (MPUC) and the North Dakota Public Service Commission (NDPSC) for several initiatives including changes to four PPAs to reduce future costs for customers.

In November 2017, the MPUC approved NSP-Minnesota's request to terminate the Pine Bend PPA but rejected its request to extend the Hennepin Energy Recover Center PPA.

In January 2018, the MPUC issued an order approving NSP-Minnesota's petition to terminate the PPAs with Benson Power LLC (Benson) and Laurentian Energy Authority I, LLC (Laurentian), as well as purchase and close the Benson biomass facility. All approved costs are expected to be recoverable through the Fuel Clause Adjustment, including a return on NSP-Minnesota's total investment in the Benson transaction through 2028. NSP-Minnesota also reached a settlement agreement with the NDPSC Staff which allows for the termination of the PPAs with Benson, Laurentian and Pine Bend, as well as the purchase and closure of the Benson biomass facility. In February 2018, the NDPSC reviewed the settlement agreement. An order is expected by the second quarter of 2018. NSP-Minnesota and NSP-Wisconsin will jointly request Federal Energy Regulatory Commission (FERC) approval to modify the Interchange Agreement to share a portion of the termination costs with NSP-Wisconsin.

These terminations and amendments are intended to provide in excess of $600 million in net cost savings to NSP System customers over the next 10 years.

NSP-Minnesota – Dakota Range — In September 2017, NSP-Minnesota filed with the MPUC seeking approval to build and own the Dakota Range project, a 300 MW wind project in South Dakota. The project is expected to be placed into service by the end of 2021 and qualify for 80 percent of the PTC.

The Minnesota Department of Commerce (DOC) filed comments and recommended the MPUC deny the petition on the basis that NSP-Minnesota did not follow the standard regulatory selection process of issuing a new request for proposal (RFP). However, the DOC acknowledged the Dakota Range project would benefit ratepayers and the MPUC could approve the project if it determines the public interest outweighs their concern about the regulatory selection process. NSP-Minnesota has requested that the MPUC approve the proposed wind project by March 2018.

NSP-Wisconsin – Wisconsin 2018 Electric and Gas Rate Case — In May 2017, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to increase electric rates by $25 million, or 3.6 percent, and natural gas rates by $12 million, or 10.1 percent, effective Jan. 1, 2018. The rate filing was based on a 2018 forecast test year (FTY), a ROE of 10.0 percent, an equity ratio of 52.53 percent and a forecasted rate base of approximately $1.2 billion for the electric utility and $138 million for the natural gas utility.

In December 2017, the PSCW approved electric and natural gas rate increases of approximately $9 million, or 1.4 percent, and $10 million, or 8.3 percent, respectively, based on a 9.8 percent ROE and an equity ratio of 51.45 percent. New rates went into effect on Jan. 1, 2018.

PSCo – Colorado 2017 Multi-Year Electric Rate Case — In October 2017, PSCo filed a multi-year request with the Colorado Public Utilities Commission (CPUC) seeking to increase electric rates approximately $245 million over four years. The request, summarized below, is based on FTYs ending Dec. 31, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	**2018**	**2019**	**2020**	**2021**	**Total**
Revenue request	$ 74	$ 75	$ 60	$ 36	$ 245
Clean Air Clean Jobs Act (CACJA) revenue conversion to base rates [(a)]	90	—	—	—	90
Transmission Cost Adjustment (TCA) revenue conversion to base rates [(a)]	43	—	—	—	43
Total [(b)]	$ 207	$ 75	$ 60	$ 36	$ 378
Expected year-end rate base (billions of dollars) [(b)]	$ 6.8	$ 7.1	$ 7.3	$ 7.4	

(a) The roll-in of the TCA and CACJA rider revenues into base rates will not have an impact on customer bills or revenue as these costs are already being recovered through a rider. Transmission investments for 2019-2021 will be recovered through the TCA rider.

(b) This base rate request does not include the impacts of the renewable energy standard adjustment and retail electric commodity adjustment for the Rush Creek wind investments or the proposed Colorado Energy Plan.

Key dates in the procedural schedule are as follows:

- Supplemental direct testimony — April 16, 2018;
- Answer testimony — May 31, 2018;
- Rebuttal and cross-answer testimony — July 10, 2018;
- Hearings — Aug. 21 - 31, 2018; and
- Statement of position — Sept. 28, 2018.

Interim rates, subject to refund and interest, will be effective on June 1, 2018. PSCo also proposed a stay-out provision and earnings test through 2021. A CPUC decision is anticipated by the end of 2018. The CPUC has opened a docket on the impact of the TCJA, which may have an impact on this rate case. For more information, see Note 5.

PSCo – Colorado 2017 Multi-Year Natural Gas Rate Case — In June 2017, PSCo filed a multi-year request with the CPUC seeking to increase retail natural gas rates approximately $139 million over three years. The request, detailed below, is based on FTYs, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	**2018**	**2019**	**2020**	**Total**
Revenue request	$ 63	$ 33	$ 43	$ 139
Pipeline System Integrity Adjustment (PSIA) revenue conversion to base rates [(a)]	—	94	—	94
Total	$ 63	$ 127	$ 43	$ 233
Expected year-end rate base (billions of dollars) [(b)]	$ 1.5	$ 2.3	$ 2.4	

(a) The roll-in of PSIA 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. The recovery of incremental PSIA related investments in 2019 and 2020 are included in the base rate request.

(b) The additional rate base in 2019 predominantly reflects the roll-in of capital associated with the PSIA rider.

In October 2017, several parties filed answer testimony. The CPUC Staff (Staff) and the Office of Consumer Counsel (OCC), recommended a single 2016 historic test year (HTY), based on an average 13-month rate base, and opposed a multi-year request. The Staff and OCC recommended an equity capital structure of 48.73 percent and 51.2 percent, respectively. Both the Staff and the OCC recommended the existing PSIA rider expire with the 2018 rates rolled into base rates beginning Jan. 1, 2019. Planned investments in 2019 and 2020 would be recoverable through base rates, subject to a future rate case. The final positions of the Staff and OCC provide for a recommended 2018 rate increase of approximately $30 million and $39 million, respectively.

In December 2017, hearings before an ALJ were held and the evidentiary record for the case was closed. Provisional rates, subject to refund, were implemented on Jan. 1, 2018. A final decision by the CPUC is anticipated in late March or early April 2018. The CPUC has opened a docket on the impact of the TCJA, which may have an impact on this rate case. For more information, see Note 5.

PSCo – Colorado Energy Plan (CEP) — In May 2016, PSCo filed its 2016 Electric Resource Plan which included the estimated need for additional generation resources through 2024. In August 2017, PSCo filed an updated capacity need with the CPUC of 450 MW.

In August 2017, PSCo and various other stakeholders filed a stipulation agreement proposing the CEP. The CEP would increase PSCo's potential capacity need up to 1,110 MW due to the proposed retirement of two coal units. The major components include:

- Early retirement of 660 MWs of coal-fired generation at Comanche Units 1 (2022) and 2 (2025);
- Accelerated depreciation for the early retirement of the two Comanche units and establishment of a regulatory asset to collect the incremental depreciation expense and related costs;
- A RFP which could result in the addition of up to 1,000 MW of wind, 700 MW of solar and 700 MW of natural gas and/or storage;
- Utility ownership targets of 50 percent renewable generation resources and 75 percent of natural gas-fired, storage, or renewable with storage generation resources;
- Reduction of the Renewable Energy Standard Adjustment rider, from two percent to one percent effective beginning 2021 or 2022; and
- Construction of a new transmission switching station to further the development of renewable generating resources.

The CPUC is expected to rule on the stipulation agreement in March 2018. PSCo is currently evaluating bids from a RFP and anticipates filing its recommended portfolios in April 2018. A CPUC decision on the recommended portfolio is anticipated in the summer of 2018.

SPS – 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 Public Utilities Commission of Texas (PUCT). The request was based on the 12-month period ended June 30, 2017, with the final three months based on estimates, a requested ROE of 10.25 percent, a Texas retail 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) revenue 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 procedural schedule are as follows:

- Intervenors' direct testimony — Feb. 22, 2018;
- PUCT Staff direct testimony — March 1, 2018;
- PUCT Staff and intervenors' cross-rebuttal testimony — March 22, 2018;
- SPS' rebuttal testimony — March 23, 2018; and
- Hearings — April 10 - 20, 2018.

The final rates are expected to be effective retroactive to Jan. 23, 2018 through a customer surcharge. A PUCT decision is expected in the third quarter of 2018. The PUCT has opened a docket on the impact of the TCJA, which may have an impact on this rate case. For more information, see Note 5.

SPS – New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the New Mexico Public Regulation Commission (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 jurisdictional 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 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).

Key dates in the procedural schedule are as follows:

- Staff and intervenor direct testimony — April 13, 2018;
- 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. The NMPRC has opened a docket on the impact of the TCJA, which may have an impact on this rate case. For more information, see Note 5.

SPS – Wind Proposals — In March 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 for a cost of approximately $1.6 billion. In addition, the proposal includes a 230 MW of wind PPA.

In December 2017, SPS and parties filed a unanimous stipulation with the NMPRC. The stipulation is subject to approval by the NMPRC. The key terms of the stipulation are listed below:

- An investment cap of $1,675 per KW, 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 can file a HTY rate case and include projected capital additions for the wind farms five months beyond the end of the test year. Interim rates would also be made effective 30 days after filing which will allow SPS to closely match the start of cost recovery for that wind farm with the in service date.

In addition, SPS has reached a settlement in principle with all parties in Texas and is working towards finalizing a stipulation. The PUCT must review and approve the stipulation before issuing a final order. Rulings by both commissions are expected by the end of the first quarter of 2018 and will likely consider the impact of the TCJA. The Hale wind project in Texas and the Sagamore wind project in New Mexico are scheduled to be in service by mid-2019 and year-end 2020, respectively.

Note 5. Tax Cuts and Jobs Act

On Dec. 22, 2017, the TCJA was signed by the President, enacting significant changes to the Internal Revenue Code (IRC). The changes are effective for Xcel Energy federal tax returns for years following 2017, and include a reduction in the federal corporate income tax rate from 35 percent to 21 percent. The TCJA recognizes the unique nature of public utilities and contains certain provisions specific to the industry, including continuing certain interest expense deductibility and not allowing 100 percent expensing of capital investments.

Summary of Expected Tax Reform Impacts

- Beneficial to our customers;
- Mildly accretive to Xcel Energy's long-term earnings. Lower deferred tax liabilities will increase rate base, offsetting higher after-tax financing costs; and
- Negative impact on cash flow from operations and credit metrics, depending on regulatory actions.

Estimated Impacts of Tax Reform

- Decreases revenue requirements by approximately $400 million;
- Reduces the tax benefit from holding company interest expense by approximately $20 million in 2018, negatively impacting earnings;
- Increases rate base growth for the same level of expected capital expenditures due to lower forecasted deferred tax liabilities;

- Requires the revaluation of federal deferred tax assets and liabilities using the new lower tax rate. The majority of the revaluation relates to regulated utility activities and results in the recording of regulatory assets and liabilities, with no estimated income statement impact. Xcel Energy recognized approximately $23 million of estimated income tax expense associated with the TCJA in the fourth quarter of 2017. This estimated amount is considered to be non-recurring and has been excluded from Xcel Energy's 2017 ongoing earnings. See Note 7 for additional information; and
- The impact on each operating company's earnings, cash flow and credit metrics is subject to the regulatory actions of our respective state commissions and the FERC.

Potential Regulatory Options

The timing of revenue adjustments for both return of excess deferred taxes and the lower tax rate are subject to regulatory actions in each of the eight states in which the regulated utilities operate, as well as the FERC. Several states have opened dockets on the impact of tax reform. Additionally, Xcel Energy has open rate cases and resource acquisition dockets pending in several states that may be impacted.

Xcel Energy plans to work directly with its regulators to determine the appropriate path forward in each jurisdiction. Potential regulatory options that may be appropriate to consider either as alternatives to or in a combination with flowing back the lower revenue requirements through rates include, but are not limited to:

- Accelerating depreciation or amortization for selected assets or asset classes;
- Increasing authorized equity ratios at the operating company level;
- Modifying capital investments;
- Avoiding or deferring future rate cases; and
- Funding of certain long-dated obligations.

Xcel Energy believes that regulatory actions that include higher authorized operating company equity ratios and/or accelerated depreciation/amortization can preserve operating company credit metrics that otherwise degrade due to return of excess deferred taxes and lower deferred tax benefits resulting from lower federal income taxes.

Revaluation of Deferred Tax Assets and Liabilities

This revaluation resulted in the recording of approximately $2.7 billion ($3.8 billion grossed-up for tax) of regulatory liabilities in the fourth quarter of 2017 which are expected to be refunded on a normalized basis over an estimated weighted average period of approximately 30 years. The revaluation of non-plant-related deferred tax assets and liabilities resulted in recording $254 million and $174 million of regulatory assets and liabilities (grossed-up for tax), respectively, in the fourth quarter of 2017.

Xcel Energy previously stated that the 2017 earnings impact attributable to the TCJA was projected to range from $65 million to $85 million. The amount recorded in the fourth quarter of 2017 was less than originally anticipated due to change in estimates in forecasted taxable income and certain deferred tax assets.

Estimated amounts included herein are based on the best information currently available. Due in part to the complexities and uncertainties associated with the TCJA, current estimates may be revised and are subject to change.

Regulatory Proceedings

Xcel Energy is in the process of quantifying the impacts of the TCJA and developing plans for addressing these impacts in its open and recently concluded proceedings focused on base rate impacts for its utility subsidiaries. In addition, the TCJA reduces the pre-tax credit that our customers receive from the federal PTCs and this issue will be addressed in various resource planning and asset acquisition proceedings. The following is a summary of the inquiries and actions related to the TCJA:

NSP-Minnesota

Minnesota: A docket has been opened in Minnesota. NSP-Minnesota will provide a detailed filing to the MPUC by Feb. 14, 2018, which will estimate the impact of the TCJA on the latest electric and natural gas rate case filings and corporate forecasts.

Dakotas: Dockets have also been opened in North Dakota and South Dakota. In February 2018, NSP-Minnesota filed comments with the South Dakota Public Utilities Commission and proposed using the reduced revenue requirements from the TCJA to defer planned future rate filings. Comments regarding TCJA impacts will also be provided to the NDPSC in February 2018.

NSP-Wisconsin

Wisconsin: In January 2018, the PSCW issued an order requiring public utilities to apply deferred accounting for the impacts of the TCJA. The PSCW has also requested that utilities provide responses to questions on tax reform and its impact on electric and natural gas revenue requirements. Responses are expected to be filed with the PSCW by Feb. 9, 2018.

Michigan: The Michigan Public Service Commission has issued an order for utilities to use deferred accounting for the impacts of the TCJA.

PSCo

Electric: PSCo and several intervenors to the Colorado 2017 multi-year electric rate case filed a non-unanimous settlement agreement with the CPUC on Jan. 30, 2018. The proposed settlement agreement covers the impacts of the TCJA for 2018 in two distinct periods: the period until June 1, 2018 (the date PSCo can implement provisional rates pursuant to its ongoing electric rate case) and the period that provisional rates are expected to be in place, or June 1, 2018 through Dec. 31, 2018. Terms to the proposed agreement include:

- PSCo will reduce base rates by an estimated $27 million from March 1, 2018 through May 31, 2018 to allocate the majority of tax benefits related to the first five months of 2018 to customers. Additionally, there will be an earnings cap for Jan. 1, 2018 through May 31, 2018 based on the currently authorized 9.83 percent ROE as a customer protection;
- Provisional rates from June 1, 2018 through Dec. 31, 2018 will be reduced to zero (instead of the annual base rate requested increase of $75 million). Revenues during this provisional rates period will be subject to refund through Dec. 31, 2018, based on the final decision of the CPUC in the 2017 electric rate case. New depreciation rates will go into effect on June 1, 2018; and
- Effective April 1, 2018, the CACJA and TCA riders will be adjusted downward based on estimated TCJA impacts (reductions of approximately $9 million for the CACJA and $5 million for the TCA on an annual basis), subject to usual CACJA and TCA true ups.

Natural gas: In January 2018, PSCo and the CPUC Staff filed a settlement agreement in the Colorado 2017 multi-year natural gas rate case to address the impacts of the TCJA in 2018. This non-unanimous settlement agreement is supported by several other intervenors, and includes an estimated $20 million reduction to provisional rates effective March 1, 2018, with future true-ups to be implemented once a full analysis of the comprehensive impacts of tax reform is performed. This analysis is expected to occur as part of a separate proceeding later in 2018. The true-up based on the final approved analysis would provide customers the full net benefit of the TCJA effective Jan. 1, 2018. The ALJ is expected to issue a recommended decision on this request in early February 2018.

Colorado: On Jan. 31, 2018, the CPUC deferred ruling on the proposed electric and natural gas settlements, and instead opened a new statewide TCJA proceeding and ordered deferred accounting. In addition to the statewide proceeding, the CPUC may consider TCJA impacts pursuant to settlements or litigation in rate cases currently before them, as well as deferred accounting issues. The CPUC is expected to rule on the regulatory treatment of the TCJA, the electric rate case and the natural gas rate case later in 2018.

SPS

Texas: In January 2018, SPS provided the PUCT a preliminary quantification of the impacts of the TCJA on its Texas 2017 electric rate case, including an adjustment to its capital structure to address the potential adverse impact on cash flow and credit metrics. On Jan. 25, 2018, the PUCT issued an order requiring utilities to apply deferred accounting for the impacts of the TCJA. SPS will provide additional information on the impacts of the TCJA by Feb. 16, 2018.

New Mexico: In February 2018, SPS provided the NMPRC a preliminary quantification of the impacts TCJA on its New Mexico 2017 electric rate case. SPS also recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially credit ratings. SPS will provide additional information on the impacts of the TCJA by Feb. 23, 2018.

Note 6. Xcel Energy Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2018 Earnings Guidance — Xcel Energy's 2018 GAAP and ongoing earnings guidance is $2.37 to $2.47 per share.[(a)] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 0.5 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to be within a range of 0 percent to 0.5 percent below 2017 levels.
- Capital rider revenue is projected to increase by $30 million to $40 million over 2017 levels. The change in assumption is due to the impact of the TCJA on riders. PTCs are flowed back to customers, primarily through capital riders and reductions to electric margin.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately $150 million to $160 million over 2017 levels. Approximately $20 million of the increase in depreciation expense reflects an increased renewable development fund, which is recovered in revenue and will not have an impact on earnings.
- Property taxes are projected to increase approximately $30 million to $40 million over 2017 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $20 million to $30 million over 2017 levels.
- AFUDC — equity is projected to increase approximately $20 million to $30 million from 2017 levels.
- The ETR is projected to be approximately 8 percent to 10 percent. The lower ETR for 2018 compared to 2017 reflects the lower tax rate as part of the TCJA, including excess deferred taxes and PTCs which are flowed back to customers through margin. The ETR would be approximately 21 percent to 23 percent excluding excess deferred taxes and PTCs.

(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 diluted EPS to corresponding GAAP diluted EPS.

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

- Deliver long-term annual EPS growth of 5 percent to 6 percent off of a 2017 base of $2.30 per share;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Note 7. Non-GAAP Reconciliation

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 communicating its earnings outlook to analysts and investors.

The following table provides a reconciliation of GAAP earnings (net income) to ongoing earnings:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	**2017**	**2016**	**2017**	**2016**
GAAP earnings	$ 189	$ 227	$ 1,148	$ 1,123
Estimated impact of TCJA	23	—	23	—
Ongoing earnings	$ 212	$ 227	$ 1,171	$ 1,123

Impact of the TCJA — Due to the enactment of the TCJA in December 2017, 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. Given the non-recurring nature of the TCJA's broad and sweeping reform of the IRC, the income tax expense associated with the TCJA enactment has been excluded from Xcel Energy's 2017 ongoing earnings.

XCEL ENERGY INC. AND SUBSIDIARIES
EARNINGS RELEASE SUMMARY (Unaudited)
(amounts in millions, except per share data)

	Three Months Ended Dec. 31	
	2017	**2016**
Operating revenues:		
Electric and natural gas	$ 2,776	$ 2,776
Other	20	19
Total operating revenues	2,796	2,795
Net income	$ 189	$ 227
Weighted average diluted common shares outstanding	509	509
Components of EPS — Diluted		
Regulated utility	$ 0.49	$ 0.48
Xcel Energy Inc. and other	(0.12)	(0.04)
GAAP diluted EPS [(a)]	**0.37**	**0.45**
Impact of the TCJA [(b)]	0.05	—
Ongoing diluted EPS	**$ 0.42**	**$ 0.45**

	Twelve Months Ended Dec. 31	
	2017	**2016**
Operating revenues:		
Electric and natural gas	$ 11,326	$ 11,031
Other	78	76
Total operating revenues	11,404	11,107
Net income	$ 1,148	$ 1,123
Weighted average diluted common shares outstanding	509	509
Components of EPS — Diluted		
Regulated utility	$ 2.47	$ 2.35
Xcel Energy Inc. and other	(0.22)	(0.15)
GAAP diluted EPS [(a)]	**2.25**	**2.21**
Impact of the TCJA [(b)]	0.05	—
Ongoing diluted EPS	**$ 2.30**	**$ 2.21**
Book value per share	$ 22.56	$ 21.73

(a) Amounts may not add due to rounding.
(b) See Notes 5 and 7.

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