414 Nicollet Mall
July 26, 2018 Minneapolis, MN 55401

XCEL ENERGY
SECOND QUARTER 2018 EARNINGS REPORT

- GAAP and ongoing 2018 second quarter earnings per share were $0.52 compared with $0.45 per share in 2017.
- Xcel Energy revised upward its 2018 guidance range to $2.41 to $2.51 per share from its previous 2018 guidance range of $2.37 to $2.47 per share.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2018 second quarter GAAP and ongoing earnings of $265 million, or $0.52 per share, compared with $227 million, or $0.45 per share in the same period in 2017.

GAAP and ongoing earnings were higher as a result of increased electric and natural gas margins (excluding the impact of the Tax Cuts and Jobs Act) which reflects favorable weather compared to last year and sales growth, and increased allowance for funds used during construction, partially offset by higher operating and maintenance expenses, as well as depreciation and interest expenses.

"Xcel Energy achieved strong quarterly and year-to-date results and is well-positioned to deliver earnings within our revised guidance range for the year," said Ben Fowke, chairman, president and CEO of Xcel Energy.

"We made outstanding progress with our industry-leading reductions in carbon emissions while delivering exceptional value to customers and stakeholders. In June, we filed our Colorado Energy Plan which, if approved, will add 1,100 MW of wind, 700 MW of solar and 275 MW of large-scale battery storage, as we retire one-third of our remaining coal generation in the state. We've also achieved key regulatory milestones and now have approvals for our new wind projects in Texas, New Mexico and South Dakota," concluded Fowke.

At 9:00 a.m. CDT 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:	(877) 260-1479
International Dial-In:	(334) 323-0522
Conference ID:	8039634

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 12:00 p.m. CDT on July 26 through 12:00 p.m. CDT on July 29.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	8039634

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 earnings per share (EPS) guidance, the Tax Cut and Jobs Act (TCJA)'s impact to Xcel Energy and its 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, 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 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.

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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 June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Operating revenues				
Electric	$ 2,348	$ 2,338	$ 4,617	$ 4,637
Natural gas	292	290	954	915
Other	18	17	38	39
Total operating revenues	2,658	2,645	5,609	5,591
Operating expenses				
Electric fuel and purchased power	935	919	1,867	1,844
Cost of natural gas sold and transported	104	114	479	479
Cost of sales — other	8	8	17	17
Operating and maintenance expenses	578	572	1,135	1,152
Conservation and demand side management expenses	69	65	139	132
Depreciation and amortization	377	366	760	731
Taxes (other than income taxes)	137	135	282	277
Total operating expenses	2,208	2,179	4,679	4,632
Operating income	450	466	930	959
Other expense, net	(2)	(4)	(1)	(4)
Equity earnings of unconsolidated subsidiaries	9	7	16	15
Allowance for funds used during construction — equity	26	16	49	31
Interest charges and financing costs				
Interest charges — includes other financing costs of $6, $6, $12, and $12, respectively	175	164	346	330
Allowance for funds used during construction — debt	(11)	(8)	(22)	(15)
Total interest charges and financing costs	164	156	324	315
Income before income taxes	319	329	670	686
Income taxes	54	102	114	219
Net income	$ 265	$ 227	$ 556	$ 467
Weighted average common shares outstanding:				
Basic	510	509	509	508
Diluted	510	509	510	509
Earnings per average common share:				
Basic	$ 0.52	$ 0.45	$ 1.09	$ 0.92
Diluted	0.52	0.45	1.09	0.92
Cash dividends declared per common share	$ 0.38	$ 0.36	$ 0.76	$ 0.72

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

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as certain non-GAAP financial measures such as electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. 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. Xcel Energy's management uses non-GAAP measures internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, 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 and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses and 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 sold and transported are generally recovered through various regulatory recovery mechanisms, and 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, operating and maintenance (O&M) expenses, conservation and demand side management (DSM) expenses, depreciation and amortization and taxes (other than income taxes).

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

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each 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 three and six months ended June 30, 2017 and 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

Note 1. Earnings Per Share Summary

The following table summarizes GAAP and ongoing diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30 2018	Three Months Ended June 30 2017	Six Months Ended June 30 2018	Six Months Ended June 30 2017
Public Service Company of Colorado (PSCo)	$ 0.24	$ 0.20	$ 0.50	$ 0.42
NSP-Minnesota	0.18	0.17	0.40	0.36
Southwestern Public Service Company (SPS)	0.11	0.07	0.18	0.12
NSP-Wisconsin	0.03	0.03	0.09	0.07
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility [a]	0.58	0.48	1.19	0.99
Xcel Energy Inc. and other	(0.06)	(0.03)	(0.10)	(0.07)
Total	**$ 0.52**	**$ 0.45**	**$ 1.09**	**$ 0.92**

[a] Amounts may not add due to rounding.

Explanations for operating company results below exclude the offsetting impacts on sales and income tax expense of the TCJA.

PSCo — Earnings increased $0.04 per share for the second quarter of 2018 and increased $0.08 per share year-to-date. The year-to-date increase in earnings was driven by higher electric and natural gas margins due to the impact of an interim rate increase, subject to refund, and favorable weather and increased allowance for funds used during construction (AFUDC) primarily related to the Rush Creek wind project. These items were partially offset by higher interest charges and depreciation expense.

NSP-Minnesota — Earnings increased $0.01 per share for the second quarter of 2018 and increased $0.04 per share year-to-date. The year-to-date increase reflects lower operating and maintenance (O&M) expenses and higher electric and natural gas margins due to favorable weather. These positive factors were partially offset by higher depreciation expense due to increased invested capital.

SPS — Earnings increased by $0.04 per share for the second quarter of 2018 and increased $0.06 per share year-to-date. 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.

NSP-Wisconsin — Earnings were flat for the second quarter of 2018 and increased $0.02 per share year-to-date. The year-to-date increase was driven by higher natural gas and electric rates and the impact of favorable weather, partially offset by additional depreciation expense related to higher invested capital.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. The decrease in earnings was primarily related to the tax impact related to the TCJA as well as higher short-term debt levels.

The following table summarizes significant components contributing to the changes in 2018 EPS compared with the same period in 2017:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
GAAP and ongoing diluted EPS — 2017	**$ 0.45**	**$ 0.92**
Components of change — 2018 vs. 2017		
Higher electric margins (excluding TCJA impacts) [a]	0.07	0.11
Higher natural gas margins (excluding TCJA impacts) [a]	0.03	0.07
Higher AFUDC — equity	0.02	0.04
(Higher) lower O&M expenses	(0.01)	0.02
(Higher) lower ETR (excluding TCJA impacts) [a] [b]	(0.01)	0.01
Higher depreciation and amortization	(0.01)	(0.03)
Higher interest charges	(0.01)	(0.02)
Higher taxes (other than income taxes)	—	(0.01)
Higher conservation and demand side management (DSM) expenses [c]	—	(0.01)
Other, net	(0.01)	(0.01)
GAAP and ongoing diluted EPS — 2018	**$ 0.52**	**$ 1.09**

[a] Estimated net impact of the TCJA, which includes assumptions regarding future outcome of pending regulatory proceedings:

	Three Months Ended June 30	Six Months Ended June 30
Income tax — rate change and ARAM (net of deferral)	$ 0.11	$ 0.21
Electric revenue reductions	(0.08)	(0.16)
Natural gas revenue reductions	(0.01)	(0.02)
Holding company — interest expense	(0.02)	(0.03)
Total	$ —	$ —

[b] The ETR includes the impact of an additional $10 million and $15 million of wind Production Tax Credits (PTCs) for the three and six months ended June 30, 2018, which are largely flowed back to customers through electric margin.

[c] Offset by higher revenues.

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 historically used per degree of temperature. Weather deviations 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.

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

	Three Months Ended June 30			Six Months Ended June 30		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
HDD	0.1%	(9.8)%	9.4%	0.3%	(8.5)%	14.8%
CDD	59.1	5.4	53.1	59.7	7.4	50.7
THI	108.1	(3.9)	125.3	107.4	(6.9)	125.1

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

	Three Months Ended June 30			Six Months Ended June 30		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
Retail electric	$ 0.065	$ 0.005	$ 0.060	$ 0.067	$ (0.021)	$ 0.088
Firm natural gas	0.002	(0.002)	0.004	0.003	(0.020)	0.023
Total (before adjustments for decoupling)	$ 0.067	$ 0.003	$ 0.064	$ 0.070	$ (0.041)	$ 0.111
Decoupling – Minnesota	(0.030)	—	(0.030)	(0.032)	0.009	(0.041)
Total (adjusted for decoupling)	$ 0.037	$ 0.003	$ 0.034	$ 0.038	$ (0.032)	$ 0.070

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2018 compared to the same period in 2017:

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	3.9%	11.9%	12.2%	9.1%	8.7%
Electric commercial and industrial	0.5	3.2	5.2	2.8	2.8
Total retail electric sales	1.6	5.5	6.4	4.3	4.4
Firm natural gas sales	(3.2)	27.5	N/A	27.6	7.2

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	0.6%	0.5%	1.5%	(0.8)%	0.6%
Electric commercial and industrial	(0.2)	0.8	4.1	1.3	1.3
Total retail electric sales	—	0.7	3.6	0.8	1.1
Firm natural gas sales	3.3	2.2	N/A	7.6	3.2

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	2.7%	7.5%	10.0%	7.0%	6.0%
Electric commercial and industrial	1.1	1.8	5.2	3.8	2.6
Total retail electric sales	1.6	3.5	6.1	4.7	3.5
Firm natural gas sales	8.4	19.3	N/A	19.2	12.6

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	0.1%	(0.5)%	1.3%	(1.1)%	(0.1)%
Electric commercial and industrial	0.7	0.1	4.5	2.8	1.5
Total retail electric sales	0.5	(0.1)	4.0	1.7	1.1
Firm natural gas sales	2.3	1.2	N/A	3.3	2.0

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

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

- PSCo's higher residential sales reflect customer additions partially offset by lower use per customer. Commercial and industrial (C&I) growth was mainly due to an increase in customers and higher use for large C&I customers that support the fabricated metal, food products and metal mining industries.
- NSP-Minnesota's residential sales decrease was a result of lower use per customer, partially offset by customer growth. The increase in C&I sales was a result of an increase in customers partially offset by lower use per customer. Increased sales to large customers in manufacturing and energy offset declines in services, largely related to energy efficiency.
- 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's residential sales decline was primarily attributable to lower use per customer partially offset by customer additions. C&I growth was largely due to higher use per large customer, customer additions and increased sales to small and large sand mining customers and large customers in the energy industries.

Weather-normalized Natural Gas Sales Growth — Year-To-Date

- Across most service territories, higher natural gas sales reflect an increase in the number of customers combined with increasing customer use.

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. The following table details the electric revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2018	2017	2018	2017
Electric revenues before impact of the TCJA	$ 2,422	$ 2,338	$ 4,755	$ 4,637
Electric fuel and purchased power before impact of the TCJA	(939)	(919)	(1,873)	(1,844)
Electric margin before impact of the TCJA	$ 1,483	$ 1,419	$ 2,882	$ 2,793
Impact of the TCJA (offset as a reduction in income tax expense)	(70)	—	(132)	—
Electric margin	$ 1,413	$ 1,419	$ 2,750	2,793

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

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Estimated impact of weather (net of Minnesota decoupling)	$ 24	$ 39
Purchased capacity costs	12	23
Retail sales growth (including Minnesota decoupling and sales true-up)	10	14
Retail rate increase (Wisconsin, Texas and Michigan)	5	12
Non-fuel riders	7	8
Other, net	6	(7)
Total increase in electric margin before impact of the TCJA	$ 64	$ 89
Impact of the TCJA (offset as a reduction in income tax expense)	(70)	(132)
Total decrease in electric margin	$ (6)	$ (43)

Natural Gas Margin — Total natural gas expense varies with changing sales 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 June 30		Six Months Ended June 30	
(Millions of Dollars)	2018	2017	2018	2017
Natural gas revenues before impact of the TCJA	$ 301	$ 290	$ 974	$ 915
Cost of natural gas sold and transported	(104)	(114)	(479)	(479)
Natural gas margin before impact of the TCJA	$ 197	$ 176	$ 495	$ 436
Impact of the TCJA (offset as a reduction in income tax expense)	(9)	—	(20)	—
Natural gas margin	$ 188	$ 176	$ 475	$ 436

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

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Retail rate increase (Colorado - interim, subject to refund, Wisconsin and Michigan)	$ 12	$ 24
Estimated impact of weather	3	18
Infrastructure and integrity riders	5	9
Sales growth	1	3
Other, net	—	5
Total increase in natural gas margin before impact of the TCJA	$ 21	$ 59
Impact of the TCJA (offset as a reduction in income tax expense)	(9)	(20)
Total increase in natural gas margin	$ 12	$ 39

O&M Expenses — O&M expenses increased $6 million, or 1.0 percent, for the second quarter of 2018 and decreased $17 million, or 1.5 percent, year-to-date. The year-to-date change largely reflects expense timing. The significant changes are summarized in the table below:

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Nuclear plant operations and amortization	$ (6)	$ (16)
Plant generation costs	8	—
Other, net	4	(1)
Total increase (decrease) in O&M expenses	$ 6	$ (17)

- Nuclear plant operations and amortization expenses are lower largely reflecting expense timing, savings initiatives and reduced refueling outage costs.

- Plant generation costs increased in the second quarter primarily due to the timing of planned maintenance and overhauls at a number of generation facilities.

Conservation and DSM Expenses — Conservation and demand side management (DSM) expenses increased $4 million, or 6.2 percent, for the second quarter of 2018 and increased $7 million, or 5.3 percent, year-to-date. The year-to-date increase was primarily due to higher recovery rates in Colorado. Increased participation in Minnesota natural gas conservation programs was partially offset by lower recovery rates. Conservation and DSM expenses 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 $11 million, or 3.0 percent, for the second quarter of 2018 and increased $29 million, or 4.0 percent, year-to-date. The increase was primarily driven by capital expenditures due to planned system investments and amortization of certain regulatory assets, partially offset by lower depreciation rates in Minnesota.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $2 million, or 1.5 percent, for the second quarter of 2018 and increased $5 million, or 1.8 percent, year-to-date. The increase was primarily due to higher property taxes in Colorado.

AFUDC, Equity and Debt — AFUDC increased $13 million for the second quarter of 2018 and $25 million year-to-date. The increase was primarily due to the Rush Creek wind project in Colorado and other capital investments.

Interest Charges — Interest charges increased $11 million, or 6.7 percent, for the second quarter of 2018 and increased $16 million, or 4.8 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 decreased $48 million for the second quarter of 2018 compared with the same period in 2017. The decrease and corresponding lower ETR was primarily driven by a lower federal tax rate due to the TCJA, an increase in plant-related regulatory differences related to ARAM[a] (net of deferrals) and an increase in wind PTCs. The ETR was 16.9 percent for the second quarter of 2018 compared with 31.0 percent for the same period in 2017.

Income tax expense decreased $105 million for the first six months of 2018 compared with the same period in 2017. The decrease and corresponding lower ETR was primarily driven by a lower federal tax rate due to the TCJA, an increase in plant-related regulatory differences related to ARAM (net of deferrals), and an increase in wind PTCs. The ETR was 17.0 percent for the first six months of 2018 compared with 31.9 percent for the same period in 2017.

	Three Months Ended June 30			Six Months Ended June 30		
	2018	**2017**	**2018 vs 2017**	**2018**	**2017**	**2018 vs 2017**
Federal statutory rate	21.0%	35.0%	(14.0)%	21.0%	35.0%	(14.0)%
State tax, net of federal tax effect	5.1%	4.1%	1.0 %	5.0%	4.1%	0.9 %
Increases (decreases) in tax from:						
Wind production tax credits	(5.4)	(4.5)	(0.9)	(5.8)	(4.2)	(1.6)
Regulatory differences - ARAM	(5.4)	(0.1)	(5.3)	(5.6)	(0.1)	(5.5)
Regulatory differences - ARAM deferral [b]	4.0	—	4.0	4.8	—	4.8
Regulatory differences - other utility plant items	(1.0)	(0.9)	(0.1)	(1.0)	(0.7)	(0.3)
Other, net	(1.4)	(2.6)	1.2	(1.4)	(2.2)	0.8
Effective income tax rate	16.9%	31.0%	(14.1)%	17.0%	31.9%	(14.9)%

[a] The average rate assumption method (ARAM); a method to flow back excess deferred taxes to customers.
[b] The ARAM deferral may decrease during the year, which would result in a reduction to tax expense with a corresponding reduction to revenue, as we receive further direction from our regulatory commissions regarding the return of excess deferred taxes to our customers resulting from the TCJA.

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

Following is the capital structure of Xcel Energy:

(Millions of Dollars)	June 30, 2018	Percentage of Total Capitalization	Dec. 31, 2017	Percentage of Total Capitalization
Current portion of long-term debt	$ 856	3%	$ 457	2%
Short-term debt	682	2	814	3
Long-term debt	15,311	54	14,520	53
Total debt	16,849	59	15,791	58
Common equity	11,650	41	11,455	42
Total capitalization	$ 28,499	100%	$ 27,246	100%

Credit Facilities — As of July 23, 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.	$ 1,250	$ 464	$ 786	$ 1	$ 787
PSCo	700	4	696	174	870
NSP-Minnesota	500	37	463	1	464
SPS	400	144	256	1	257
NSP-Wisconsin	150	48	102	1	103
Total	$ 3,000	$ 697	$ 2,303	$ 178	$ 2,481

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

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

Credit Ratings — Access to the capital market at reasonable terms is partially dependent 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 July 23, 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

2018 Planned Financing Activity — During 2018, Xcel Energy Inc. and its utility subsidiaries issued and anticipate issuing the following:

- PSCo issued $350 million of 3.70 percent first mortgage green bonds due June 15, 2028 and $350 million of 4.10 percent first mortgage green bonds due June 15, 2048;
- Xcel Energy Inc. issued $500 of 4.0 percent senior notes due June 15, 2028;
- NSP-Wisconsin plans to issue approximately $200 million of first mortgage bonds; and
- SPS plans to issue approximately $250 million of first mortgage bonds.

Xcel Energy also plans to issue approximately $300 million of incremental equity in 2018 in addition to approximately $75 million of equity to be issued through the dividend reinvestment program and benefit programs.

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

Note 4. Rates and Regulation

NSP-Minnesota – Wind Development — In 2017, the Minnesota Public Utility Commission (MPUC) approved NSP-Minnesota's proposal to add 1,550 megawatts (MW) of new wind generation including ownership of 1,150 MW of wind generation. An order from the NDPSC is expected later in 2018.

Dakota Range — In April 2018, the MPUC approved NSP-Minnesota's petition to build and own the Dakota Range, a 300 megawatt (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. NSP-Minnesota's total capital investment for the Dakota Range is expected to be approximately $350 million. A North Dakota Public Service Commission decision is expected later in 2018.

PSCo – Colorado 2017 Multi-Year Natural Gas Rate Case — In June 2017, PSCo filed a multi-year request with the Colorado Public Utilities Commission (CPUC) seeking to increase retail natural gas rates approximately $139 million over three years. The request, detailed below, was based on forecast test years (FTY), a 10.0 percent return on equity (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) rider 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 February 2018, the administrative law judge (ALJ) approved a TCJA settlement agreement between PSCo and the CPUC Staff, which reduced provisional rates by $20 million, based on a preliminary TCJA estimate of $29 million. The settlement remains subject to CPUC approval. The impact of the TCJA will be trued-up later in 2018. Annualized provisional rates of approximately $43 million were effective March 1, 2018.

In May 2018, the ALJ issued an interim recommended decision which would result in a 2018 overall rate increase of approximately $46 million, prior to the impact of the TCJA. The estimated rate increase reflects a 2016 HTY with a 13-month average rate base of $1.6 billion, a ROE of 9.35 percent and an equity ratio of 54.2 percent.

On July 12, 2018, the CPUC deliberated and approved several of the ALJ's recommendations including application of a 2016 historic test year (HTY), with a 13-month average rate base, and an ROE of 9.35 percent. The CPUC adjusted the equity ratio to 54.6 percent and provided no return on the prepaid pension and retiree medical asset. With these adjustments the total rate increase, prior to TCJA impacts, would be $47 million.

The estimated impact of the CPUC's decision is presented below:

(Millions of Dollars)		Estimated Impact of the CPUC's Decision
Filed 2018 revenue request based on a FTY	$	63
Impact of the change in test year		5
PSCo's deficiency based on a 2016 HTY - year-end rate base		68
Adjustments:		
ROE at 9.35 percent		(9)
Equity ratio of 54.6 percent		(2)
Change in amortization period for certain regulatory assets, including a debt return		(6)
Loss of return on prepaid pension and retiree medical		(4)
Change from 2016 year-end to average rate base		(5)
Other, net		5
Total adjustments		(21)
Total rate increase, prior to the TCJA impacts	$	47

The CPUC is expected to issue its order on the natural gas rate case in the third quarter of 2018. The CPUC is expected to issue a final decision with the impacts of the TCJA, later in 2018.

PSIA Rider

In June 2018, PSCo filed for an extension to the PSIA rider through 2020. PSCo requested an expedited decision by Nov. 15, 2018. PSCo also requested authorization to roll-in recovery of costs in the current PSIA rider into base rates effective Jan. 1, 2019, if the CPUC rejects the proposed PSIA extension or fails to rule on the request by the end of 2018.

Additionally, PSCo reduced PSIA revenues by approximately $8 million for 2018 for the impact of the TCJA, effective May 1, 2018. PSIA revenues are subject to the CPUC approved PSIA rider true-up process.

PSCo – Colorado Energy Plan (CEP) — In 2016, PSCo filed its 2016 Electric Resource Plan (ERP) which included the estimated need for additional generation resources through spring of 2024. In 2017, PSCo filed an updated capacity need with the CPUC of 450 MW in 2023.

In 2017, PSCo and various other stakeholders filed a stipulation agreement proposing the CEP, an alternative plan that increases PSCo's potential capacity need up to 1,110 MW due to the proposed retirement of two coal units.

In June 2018, PSCo filed its 120-day update report with the CPUC which includes multiple portfolios and recommends a preferred CEP portfolio. PSCo's investment under the preferred CEP portfolio would be approximately $1 billion, including investment in transmission to support the significant increase in renewable generation in the state. The preferred CEP portfolio includes the following additions as well as the retirement of the two coal-fired generation units:

	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

On July 13, 2018, the Independent Evaluator (IE) for the ERP filed their report on the process, modeling and evaluation of the various offers received through the RFP process. Generally, the IE report was favorable to the process employed and the outcomes included in the modeling. Certain recommendations for future ERP processes were provided with a primary focus regarding enhanced modeling of new resource types such as battery storage.

On July 23, 2018, various stakeholders commented on the 120-day update report for the ERP and the CEP. Many community, advocate and developer interests supported the CEP, while certain stakeholders opposed the CEP and the associated early coal plant retirements. The CPUC staff indicated that PSCo's preferred CEP plan is a valid option, but expressed concerns on the saving assumptions, complexity of modeling and the utilization of production tax credits.

A CPUC decision is anticipated in September 2018.

SPS – 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 Public Utility Commission of Texas (PUCT). The request was based on a HTY ended June 30, 2017, a requested 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. 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 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.

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 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.

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.

SPS – 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.

Note 5. Tax Cuts and Jobs Act

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 have opened dockets to address the impacts of the TCJA.

NSP-Minnesota — In April 2018, NSP-Minnesota updated the estimated impact of the TCJA, which reflected an overall reduction in 2018 revenue requirements of approximately $136 million for electric and $7 million for natural gas, and made recommendations regarding the sharing of those benefits with ratepayers. The proposed electric options included: customer refunds and rider impacts of $68 million, deferral of $44 million to allow for a rate case stay-out for 2020, acceleration of depreciation for the King coal plant of $22 million and low income program funding of $2 million. The proposed natural gas options included customer refunds and rider impacts of $3 million, with the remaining TCJA benefits deferred to mitigate increased costs in the next natural gas rate case.

In June 2018, the Minnesota Department of Commerce (DOC) recommended to implement refunds for the current tax impacts (approximately $90 million), and incorporate the deferred tax impacts (approximately $53 million) in NSP-Minnesota's next electric and gas rate cases. A decision from the MPUC is expected in 2018.

NSP-Minnesota — North and South Dakota — In February 2018, NSP-Minnesota proposed using the reduced revenue requirements from the TCJA to defer planned future rate filings in North Dakota and South Dakota. In July 2018, the South Dakota Public Utilities Commission (SDPUC) approved a settlement which proposed a one-time customer refund of $11 million for the 2018 impact of the TCJA and a two-year rate case moratorium.

NSP-Wisconsin — In May 2018, the Public Service Commission of Wisconsin issued its final order which requires customer refunds of $27 million and defers approximately $5 million until NSP-Wisconsin's next rate case proceeding.

NSP-Wisconsin — Michigan — In May 2018, the Michigan Public Service Commission approved electric and natural gas tax reform settlement agreements. Most of the electric TCJA benefits were included in NSP-Wisconsin's recently approved Michigan 2018 electric base rate case. Natural gas TCJA benefits are to be returned to customers commencing in July 2018.

PSCo — Colorado Natural Gas — In February 2018, the ALJ approved PSCo and the CPUC Staff's TCJA settlement agreement which includes a $20 million reduction to provisional rates effective March 1, 2018. A final true-up would provide customers the full net benefit of the TCJA retroactive to January 2018.

PSCo — Colorado Electric — In April 2018, PSCo, the CPUC Staff and the Office of Consumer Counsel filed a TCJA settlement agreement that recommended a customer refund of $42 million in 2018, with the remainder of $59 million be used to accelerate the amortization of an existing prepaid pension asset. In June 2018, the CPUC approved the customer refund of $42 million, effective June 1, 2018. The CPUC set the decision regarding the remainder of the $59 million for hearing before an ALJ. Revisions to the TCJA settlement will be addressed in a future electric rate case.

SPS — Texas — In June 2018, SPS, the 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.

SPS — 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, as discussed in Note 4.

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

Xcel Energy 2018 Earnings Guidance — Xcel Energy revised upward its 2018 guidance range to $2.41 to $2.51 per share from its previous 2018 guidance range of $2.37 to $2.47 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the remainder of the year.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 1.0 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to increase 1.0 percent to 1.5 percent over 2017 levels.
- Capital rider revenue is projected to increase $40 million to $50 million over 2017 levels. PTCs are flowed back to customers, primarily through capital riders and reductions to electric margin.
- O&M expenses are projected to increase 1 percent to 2 percent over 2017 levels.
- Depreciation expense is projected to increase approximately $100 million to $110 million over 2017 levels.
- Property taxes are projected to increase approximately $10 million to $20 million over 2017 levels.
- Interest expense (net of AFUDC - debt) is projected to increase $30 million to $40 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 15 percent to 17 percent. This range may decrease to 8 percent to 10 percent as we receive clarity and direction from our commissions as to the treatment of excess deferred taxes that resulted from the TCJA. A reduction to the ETR resulting from the flowback of excess deferred taxes would be offset by a correlated reduction to revenue. Additionally, the lower ETR for 2018 compared to 2017 reflects additional PTCs which are flowed back to customers through margin.

[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.

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

	Three Months Ended June 30	
	2018	2017
Operating revenues:		
Electric and natural gas	$ 2,640	$ 2,628
Other	18	17
Total operating revenues	2,658	2,645
Net income	$ 265	$ 227
Weighted average diluted common shares outstanding	510	509
Components of EPS — Diluted		
Regulated utility	$ 0.58	$ 0.48
Xcel Energy Inc. and other costs	(0.06)	(0.03)
GAAP and ongoing diluted EPS	**$ 0.52**	**$ 0.45**

	Six Months Ended June 30	
	2018	2017
Operating revenues:		
Electric and natural gas	$ 5,571	$ 5,552
Other	38	39
Total operating revenues	5,609	5,591
Net income	$ 556	$ 467
Weighted average diluted common shares outstanding	510	509
Components of EPS — Diluted		
Regulated utility	$ 1.19	$ 0.99
Xcel Energy Inc. and other costs	(0.10)	(0.07)
GAAP and ongoing diluted EPS	**1.09**	**0.92**
Book value per share	$ 22.90	$ 21.91