Aug. 3, 2016

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
SECOND QUARTER 2016 EARNINGS REPORT

- GAAP (generally accepted accounting principles) and ongoing 2016 second quarter earnings per share were $0.39 compared with $0.39 per share in 2015.
- Xcel Energy reaffirms 2016 ongoing earnings guidance of $2.12 to $2.27 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2016 second quarter GAAP and ongoing earnings of $197 million, or $0.39 per share, compared with $197 million, or $0.39 per share, in the same period in 2015.

Higher electric and gas margins in the second quarter of 2016 were primarily due to higher retail electric and natural gas rates across various jurisdictions, non-fuel riders and the impact of favorable weather. These positive factors were offset by higher depreciation, interest charges and property taxes.

"While we continue to see lower than expected sales across much of our operating territory, our teams continue to carefully manage our O&M expenses and take a thoughtful approach to delivering on our business objectives. As a result, we fully expect to deliver ongoing earnings solidly within our 2016 guidance range," said Chairman, President and CEO Ben Fowke.

"We've made significant progress in our regulatory initiatives including filing a resource plan, a decoupling proposal and a distribution grid modernization program, all in Colorado," said Fowke. "In addition, we received strong support for our Rush Creek wind project and are making good progress in working towards a settlement in our Minnesota rate case."

Earnings Adjusted for Certain Items (Ongoing Earnings)

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

	Three Months Ended June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	**2016**	**2015**	**2016**	**2015**
Ongoing diluted EPS	**$ 0.39**	**$ 0.39**	**$ 0.86**	**$ 0.85**
Loss on Monticello life cycle management/extended power uprate project [a]	—	—	—	(0.16)
GAAP diluted EPS	**$ 0.39**	**$ 0.39**	**$ 0.86**	**$ 0.69**

[a] See Note 6.

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:	(888) 427-9421
International Dial-In:	(719) 457-2619
Conference ID:	2308404

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 Aug. 3 through 10:59 p.m. CDT on Aug. 5.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	2308404

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 2016 earnings per share guidance and assumptions, are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. 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, 2015, Quarterly Report on Form 10-Q for the quarter ended March 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; availability of cost of capital; and employee work force factors.

For more information, contact:

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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 thousands, except per share data)

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Operating revenues				
Electric	$ 2,224,142	$ 2,213,460	$ 4,409,261	$ 4,438,323
Natural gas	258,899	284,131	824,588	1,000,127
Other	16,808	17,543	38,273	38,903
Total operating revenues	2,499,849	2,515,134	5,272,122	5,477,353
Operating expenses				
Electric fuel and purchased power	855,968	904,705	1,717,820	1,854,837
Cost of natural gas sold and transported	90,071	126,667	402,188	599,038
Cost of sales — other	8,332	8,164	16,577	18,213
Operating and maintenance expenses	596,978	594,279	1,174,388	1,180,109
Conservation and demand side management program expenses	55,916	54,141	113,352	107,946
Depreciation and amortization	322,534	274,602	642,554	547,700
Taxes (other than income taxes)	138,469	129,731	283,792	266,357
Loss on Monticello life cycle management/extended power uprate project	—	—	—	129,463
Total operating expenses	2,068,268	2,092,289	4,350,671	4,703,663
Operating income	431,581	422,845	921,451	773,690
Other income, net	1,560	961	5,810	4,122
Equity earnings of unconsolidated subsidiaries	9,617	8,422	22,799	16,198
Allowance for funds used during construction — equity	14,730	12,641	27,843	25,301
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,630, $5,861, $12,966 and $11,559, respectively	162,980	144,222	319,423	289,162
Allowance for funds used during construction — debt	(6,684)	(6,165)	(12,674)	(12,309)
Total interest charges and financing costs	156,296	138,057	306,749	276,853
Income before income taxes	301,192	306,812	671,154	542,458
Income taxes	104,397	109,881	233,047	193,461
Net income	$ 196,795	$ 196,931	$ 438,107	$ 348,997
Weighted average common shares outstanding:				
Basic	508,930	507,707	508,789	507,359
Diluted	509,490	508,074	509,311	507,747
Earnings per average common share:				
Basic	$ 0.39	$ 0.39	$ 0.86	$ 0.69
Diluted	0.39	0.39	0.86	0.69
Cash dividends declared per common share	$ 0.34	$ 0.32	$ 0.68	$ 0.64

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Investor Relations Earnings Release (Unaudited)

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 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 for Xcel Energy and by subsidiary is a financial measure 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 items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe this measurement is useful to investors in facilitating period over period comparisons and evaluating or projecting financial results. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

Note 1. Earnings Per Share Summary

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	**2016**	**2015**	**2016**	**2015**
Public Service Company of Colorado (PSCo)	$ 0.17	$ 0.19	$ 0.40	$ 0.41
NSP-Minnesota	0.15	0.15	0.34	0.32
Southwestern Public Service Company (SPS)	0.06	0.05	0.11	0.08
NSP-Wisconsin	0.02	0.02	0.06	0.07
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.02
Regulated utility [(a)]	0.42	0.42	0.93	0.90
Xcel Energy Inc. and other	(0.04)	(0.03)	(0.07)	(0.05)
Ongoing diluted EPS [(a)]	0.39	0.39	0.86	0.85
Loss on Monticello life cycle management (LCM)/extended power uprate (EPU) project [(b)]	—	—	—	(0.16)
GAAP diluted EPS	**$ 0.39**	**$ 0.39**	**$ 0.86**	**$ 0.69**

(a) Amounts may not add due to rounding.
(b) See Note 6.

PSCo — PSCo's ongoing earnings decreased $0.02 per share for the second quarter of 2016 and $0.01 per share year-to-date. Year-to-date, the positive impact of higher natural gas revenues due to rate increases was more than offset by higher depreciation, operating and maintenance (O&M) expenses, interest charges and the favorable impact of an adjustment to the estimated electric earnings test refund obligation recognized in 2015.

NSP-Minnesota — NSP-Minnesota's ongoing earnings were flat for the second quarter of 2016 and increased $0.02 per share year-to-date. Year-to-date, higher electric revenues driven by a rate increase in Minnesota (interim, subject to refund) and non-fuel riders were partially offset by higher depreciation, property taxes, O&M expenses and interest charges.

SPS — SPS' ongoing earnings increased $0.01 for the second quarter of 2016 and $0.03 per share year-to-date. Year-to-date, higher electric margin and lower O&M expenses were partially offset by additional depreciation.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings per share were flat for the second quarter of 2016 and decreased $0.01 year-to-date. Year-to-date, higher electric margins primarily driven by an electric rate increase were more than offset by higher O&M expenses and depreciation.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Ongoing earnings decreased by $0.01 for the second quarter of 2016 and $0.02 per share year-to-date, primarily related to higher long-term debt levels.

The following table summarizes significant components contributing to the changes in 2016 EPS compared with the same period in 2015:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
2015 GAAP diluted EPS	**$ 0.39**	**$ 0.69**
Loss on Monticello LCM/EPU project [(a)]	—	0.16
2015 ongoing diluted EPS	**0.39**	**0.85**
Components of change — 2016 vs. 2015		
Higher electric margins [(b)]	0.07	0.13
Higher natural gas margins [(c)]	0.01	0.03
Lower O&M expenses	—	0.01
Higher depreciation and amortization	(0.06)	(0.11)
Higher interest charges	(0.02)	(0.04)
Higher taxes (other than income taxes)	(0.01)	(0.02)
Other, net	0.01	0.01
2016 GAAP and ongoing diluted EPS	**$ 0.39**	**$ 0.86**

(a) See Note 6.
(b) Reflects $0.022 and $0.008 attributable to weather for the three and six months ended June 30, 2016, respectively.
(c) Reflects $0.001 and $(0.008) attributable to weather for the three and six months ended June 30, 2016, respectively.

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 is provided in the following table:

	Three Months Ended June 30			Six Months Ended June 30		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
HDD	(3.7)%	(8.1)%	4.9%	(11.5)%	(2.4)%	(8.6)%
CDD	1.7	(19.1)	25.8	1.7	(19.2)	26.4
THI	15.8	(20.8)	45.5	15.4	(21.0)	45.6

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

	Three Months Ended June 30			Six Months Ended June 30		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
Retail electric	$ 0.009 [(a)]	$ (0.013)	$ 0.022	$ (0.005) [(a)]	$ (0.013)	$ 0.008
Firm natural gas	—	(0.001)	0.001	(0.013)	(0.005)	(0.008)
Total	$ 0.009	$ (0.014)	$ 0.023	$ (0.018)	$ (0.018)	$ —

(a) Excludes $0.006 and $0.001 favorable weather impact due to electric sales decoupling at NSP-Minnesota for the three and six months ended June 30, 2016, respectively.

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2016:

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	5.6%	4.8%	(0.9)%	4.6%	4.3%
Electric commercial and industrial	(1.7)	(0.7)	1.0	—	(0.6)
Total retail electric sales	0.5	0.8	0.7	1.0	0.7
Firm natural gas sales	7.5	4.2	N/A	(6.4)	5.8

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	3.9%	0.1%	(5.6)%	0.8%	0.7%
Electric commercial and industrial	(2.2)	(1.7)	(0.5)	(0.7)	(1.5)
Total retail electric sales	(0.4)	(1.2)	(1.4)	(0.4)	(0.9)
Firm natural gas sales	5.5	1.6	N/A	(9.7)	3.4

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	3.3%	(0.1)%	(3.8)%	(2.2)%	0.5%
Electric commercial and industrial	(1.1)	(1.0)	0.5	(0.5)	(0.6)
Total retail electric sales	0.3	(0.7)	(0.2)	(1.1)	(0.3)
Firm natural gas sales	3.2	(9.4)	N/A	(12.4)	(2.0)

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	2.5%	(0.3)%	(2.6)%	(1.0)%	0.4%
Electric commercial and industrial	(1.4)	(1.2)	(0.1)	(0.5)	(1.0)
Total retail electric sales	(0.1)	(1.0)	(0.5)	(0.7)	(0.6)
Firm natural gas sales	1.2	(0.2)	N/A	(3.6)	0.4

	Six Months Ended June 30 (Excluding Leap Day) [b]				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential [a]	1.9%	(0.9)%	(3.2)%	(1.6)%	(0.2)%
Electric commercial and industrial	(2.0)	(1.8)	(0.6)	(1.0)	(1.5)
Total retail electric sales	(0.7)	(1.5)	(1.1)	(1.3)	(1.1)
Firm natural gas sales	0.4	(1.0)	N/A	(4.5)	(0.4)

(a) Extreme weather variations and additional factors such as windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

(b) In order to assess comparable periods, Xcel Energy excluded the estimated impact of the 2016 leap day to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 50-60 basis points for retail electric and 80-90 basis points for firm natural gas for the sixth months ended.

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

- PSCo's residential growth reflects an increased number of customers. The commercial and industrial (C&I) decline was mainly due to lower sales to certain large customers that support the mining industry and oil and gas industries.

- NSP-Minnesota's residential sales decreased primarily due to lower use per customer, partially offset by an increase in customer additions. The C&I sales declined as a result of lower use by large customers primarily in the manufacturing industry. The sales decrease was partially mitigated by an increase in the number of customers within the small customer class.

- SPS' residential sales decline was primarily the result of lower use per customer, partially offset by customer additions. The C&I sales decreased as a result of reduced activity within the oil and gas industries for the small customer class. The decline was partially reduced by customer additions in both the large and small customer classes.

- NSP-Wisconsin's residential sales decrease was primarily attributable to lower use per customer, partially offset by customer additions. The C&I decline was primarily due to reduced sales to small customers in the sand mining industry. The overall decrease was partially offset by an increase in the number of large and small C&I customers as well as greater use per customer in the large C&I class for the oil and gas industries.

Weather-normalized Natural Gas Sales Decline — Year-To-Date (Excluding Leap Day)

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

Electric Margin — Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2016	2015	2016	2015
Electric revenues	$ 2,224	$ 2,213	$ 4,409	$ 4,438
Electric fuel and purchased power	(856)	(905)	(1,718)	(1,855)
Electric margin	$ 1,368	$ 1,308	$ 2,691	$ 2,583

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

(Millions of Dollars)	Three Months Ended June 30 2016 vs. 2015	Six Months Ended June 30 2016 vs. 2015
Retail rate increases [(a)]	$ 30	$ 68
Transmission revenue, net of costs	11	12
Non-fuel riders	3	10
Estimated impact of weather	22	8
PSCo earnings test refund	(6)	(6)
Weather decoupling-Minnesota	(5)	(1)
Other, net	5	17
Total increase in electric margin	$ 60	$ 108

(a) Increase is primarily due to rate proceedings in Minnesota (interim, subject to and net of estimated provision for refund) and Wisconsin.

Natural Gas Margin — Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms for sales to retail customers, fluctuations in the cost of natural gas has minimal impact on natural gas margin. The following table details natural gas revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2016	2015	2016	2015
Natural gas revenues	$ 259	$ 284	$ 825	$ 1,000
Cost of natural gas sold and transported	(90)	(127)	(402)	(599)
Natural gas margin	$ 169	$ 157	$ 423	$ 401

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

(Millions of Dollars)	Three Months Ended June 30 2016 vs. 2015	Six Months Ended June 30 2016 vs. 2015
Retail rate increases [(a)]	$ 11	$ 24
Estimated impact of weather	1	(6)
Other, net	—	4
Total increase in natural gas margin	$ 12	$ 22

(a) Increase is primarily related to Colorado.

O&M Expenses — O&M expenses increased $2.7 million, or 0.5 percent, for the second quarter of 2016 and decreased $5.7 million, or 0.5 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. The year-to-date decrease was mainly due to the timing and scope of plant outages and discovery work along with lower nuclear outage and outage amortization costs, which were partially offset by higher gas survey and damage prevention costs.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses increased $1.8 million, or 3.3 percent, for the second quarter of 2016 and $5.4 million, or 5.0 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to higher electric and natural gas recovery rates at NSP-Minnesota, partially reduced by lower electric recovery rates at PSCo. Higher conservation and DSM program expenses are generally offset by higher revenues.

Depreciation and Amortization — Depreciation and amortization increased $47.9 million, or 17.5 percent, for the second quarter of 2016 and $94.9 million, or 17.3 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to capital investments, including Pleasant Valley and Border Wind Farms, which were placed into service in late 2015.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $8.7 million, or 6.7 percent, for the second quarter of 2016 and $17.4 million, or 6.5 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. Increases were due to higher property taxes primarily in Minnesota.

Interest Charges — Interest charges increased $18.8 million, or 13.0 percent, for the second quarter of 2016 and $30.3, or 10.5 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. The increase was related to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $5.5 million for the second quarter of 2016 compared with the same period in 2015. The decrease was primarily due to lower pretax earnings in 2016 and increased wind production tax credits in 2016. The effective tax rate (ETR) was 34.7 percent for the second quarter of 2016 compared with 35.8 percent for the same period in 2015. The lower ETR in 2016 is primarily due to increased wind production tax credits.

Income tax expense increased $39.6 million for the first six months of 2016 compared with the same period in 2015. The increase in income tax expense was primarily due to higher pretax earnings in the six months ended June 30, 2016, partially offset by increased wind production tax credits. The ETR was 34.7 percent for the first six months of 2016 compared with 35.7 percent for the same period in 2015. The lower ETR in 2016 is primarily due to increased wind production tax credits.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	June 30, 2016	Percentage of Total Capitalization	Dec. 31, 2015	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.7	3%	$ 0.7	3%
Short-term debt	0.5	2	0.8	3
Long-term debt	13.1	52	12.4	51
Total debt	14.3	57	13.9	57
Common equity	10.7	43	10.6	43
Total capitalization	$ 25.0	100%	$ 24.5	100%

Credit Facilities — As of July 25, 2016, 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.	$ 1,000	$ 401	$ 599	$ —	$ 599
PSCo	700	98	602	1	603
NSP-Minnesota	500	18	482	1	483
SPS	400	95	305	1	306
NSP-Wisconsin	150	23	127	—	127
Total	$ 2,750	$ 635	$ 2,115	$ 3	$ 2,118

(a) These credit facilities expire in June 2021.
(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 July 25, 2016, 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

Xcel Energy Inc.'s and its utility subsidiaries' 2016 financing plans reflect the following:

- In March, Xcel Energy Inc. issued $400 million of 2.4 percent senior notes due March 15, 2021 and $350 million of 3.3 percent senior notes due June 1, 2025;
- In May, NSP-Minnesota issued $350 million of 3.6 percent first mortgage bonds due May 15, 2046;
- In June, PSCo issued $250 million of 3.55 percent first mortgage bonds due June 15, 2046; and
- SPS plans to issue approximately $300 million of first mortgage bonds in the third quarter.

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 – Minnesota 2016 Multi-Year Electric Rate Case — In November 2015, NSP-Minnesota filed a three-year electric rate case with the Minnesota Public Utilities Commission (MPUC). The rate case is based on a requested return on equity (ROE) of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below:

Request (Millions of Dollars)	2016	2017	2018
Rate request	$ 194.6	$ 52.1	$ 50.4
Increase percentage	6.4%	1.7%	1.7%
Interim request	$ 163.7	$ 44.9	N/A
Rate base	$ 7,800	$ 7,700	$ 7,700

In December 2015, the MPUC approved interim rates for 2016.

Intervenor Testimony:
In June 2016, intervening parties filed direct testimony proposing modifications to NSP-Minnesota's rate request. The Minnesota Department of Commerce (DOC) subsequently filed revised testimony recommending an increase of approximately $45.6 million in 2016, a step increase of $53.8 million for 2017, and a step decrease of $5.0 million for 2018, based on a recommended ROE of 9.06 percent and an equity ratio of 52.50 percent.

Based on NSP-Minnesota's interpretation of the DOC's testimony, certain recommended adjustments of approximately $72.7 million would not be expected to impact earnings, assuming MPUC approval. The following table summarizes NSP-Minnesota's estimate of the DOC's recommendations:

(Millions of Dollars)	2016	2017 Step	2018 Step	Total
Filed rate request	$ 194.6	$ 52.1	$ 50.4	$ 297.1
DOC recommended adjustments:				
ROE	(65.0)	0.3	1.0	(63.7)
Sales forecast	(39.4)	—	—	(39.4)
Property tax	(5.2)	(0.3)	(0.1)	(5.6)
Depreciation life	(8.0)	0.4	(2.2)	(9.8)
Purchased demand timing changes	—	—	(19.4)	(19.4)
Nuclear capital costs	(3.6)	0.8	(11.2)	(14.0)
Tax related items	(12.2)	18.4	(6.9)	(0.7)
Operating and maintenance (O&M)	(15.5)	(17.8)	(16.7)	(50.0)
Other, net	(0.1)	(0.1)	0.1	(0.1)
Total DOC Adjustments	(149.0)	1.7	(55.4)	(202.7)
Total DOC recommended rate increase	$ 45.6	$ 53.8	$ (5.0)	$ 94.4
Estimated non-earnings DOC adjustments:				
Depreciation life	8.0	(0.4)	2.2	9.8
Sales forecast	37.4	—	—	37.4
Property tax	5.2	0.3	0.1	5.6
Purchased demand timing changes	—	—	19.4	19.4
Other	0.5	—	—	0.5
Total estimated non-earnings adjustments	51.1	(0.1)	21.7	72.7
Total pre-tax earnings impact	$ 96.7	$ 53.7	$ 16.7	$ 167.1

The DOC also presented several nuclear recommendations related to capital recovery for spent fuel storage investments and Prairie Island LCM projects.

- The use of certificate of need estimates as a recovery cap, and/or provisionally exclude recovery of amounts in excess of the cap unless the costs are deemed reasonable by the DOC's nuclear consultant and/or the MPUC.
- No recovery of a portion of capital costs associated with Monticello fuel storage Cask 16, representing the amount beyond the originally anticipated project cost, or approximately $15 million. The additional costs incurred were for testing of cask lid welds to demonstrate compliance with Nuclear Regulatory Commission requirements.

Settlement Agreement

In August 2016, NSP-Minnesota reached a settlement in principal with several of the parties, which resolves all revenue requirement issues in dispute. The terms and conditions of the agreement are still subject to final documentation. The settlement agreement requires the approval of the MPUC.

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

- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;
- Evidentiary hearing — Oct. 4-7, 2016;
- Administrative Law Judge report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

A current liability representing NSP-Minnesota's best estimate of a refund obligation for 2016 associated with interim rates was recorded as of June 30, 2016.

NSP-Minnesota – Gas Utility Infrastructure Costs (GUIC) Rider — In July 2016, the MPUC verbally approved NSP-Minnesota's request to recover approximately $15 million in natural gas infrastructure costs through the GUIC Rider, based on NSP-Minnesota's proposed capital structure and a ROE of 9.64 percent, as proposed by the DOC. Recovery was approved for the 15-month period from January 2016 to March 2017.

NSP-Wisconsin – Wisconsin 2017 Electric and Gas Rate Case — In April 2016, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) for an increase in annual electric rates of $17.4 million, or 2.4 percent, and an increase in natural gas rates by $4.8 million, or 3.9 percent, effective January 2017.

The following table outlines the filed request:

Electric Rate Request (Millions of Dollars)	Request
Rate base investments	$ 11.0
Generation and transmission expenses (excluding fuel and purchased power)	6.8
Fuel and purchased power expenses	11.0
Subtotal	28.8
2015 fuel refund [a]	(9.5)
DOE settlement refund	(1.9)
Total electric rate increase	$ 17.4

(a) In July 2016, the PSCW required NSP-Wisconsin to return the 2015 fuel refund directly to customers, rather than using it to offset the proposed 2017 rate increase, as originally proposed by NSP-Wisconsin. This decision effectively increases NSP-Wisconsin's requested electric rate increase to $26.9 million, or 3.8 percent.

The electric rate request is for the limited purpose of recovering increases in (1) generation and transmission fixed charges and fuel and purchased power expenses related to the interchange agreement with NSP-Minnesota, and (2) costs associated with forecasted average rate base of $1.188 billion in 2017.

The natural gas rate request is for the limited purpose of recovering expenses related to the ongoing environmental remediation of a former manufactured gas plant site and adjacent area in Ashland, Wis.

No changes are being requested to the capital structure or the 10.0 percent ROE authorized by the PSCW in the 2016 rate case. As part of an agreement with stakeholders to limit the size and scope of the case, NSP-Wisconsin also agreed to an earnings cap, solely for 2017, in which 100 percent of the earnings in excess of the authorized ROE would be refunded to customers.

Key dates in the procedural schedule are as follows:

- Staff and intervenor direct testimony — Aug. 12, 2016;
- Rebuttal testimony — Aug. 26, 2016;
- Surrebuttal testimony — Sept. 2, 2016;
- Hearing — Sept. 7, 2016;
- Initial brief due — Sept. 21, 2016;
- Reply brief due — Sept. 28, 2016; and
- A final PSCW decision is anticipated in the fourth quarter of 2016 with final rates effective in January 2017.

PSCo – Rush Creek Wind Ownership Proposal — In May 2016, PSCo filed an application to build, own and operate a 600 MW wind generation facility at a cost of approximately $1 billion, including transmission investment. PSCo requested approval of the proposal by November 2016, in order to commence the project timely and capture the full production tax credit benefit for customers.

Colorado legislation allows for utilities to own up to 50 percent of new renewable resources without a competitive bidding process if projects can be developed at a reasonable price and demonstrate economic benefit.

PSCo believes its proposed facility can be constructed at a reasonable cost compared to the cost of similar renewable resources available on the market, and that it will be able to demonstrate to the CPUC and the independent evaluator that the proposed wind project meets the reasonable price and economic benefit standards. If approved by the CPUC, the new facility is projected to go into service in December 2018.

Intervenors responded to PSCo's application and answer testimony was filed in July 2016. The next steps in the procedural schedule are as follows:

- PSCo's rebuttal testimony — Aug. 22, 2016; and
- Hearings — Sept. 7-9, 2016.

PSCo – Natural Gas Reserves Investments — In January 2016, PSCo filed a request with the CPUC for approval of a long-term natural gas procurement and price hedging framework. In June 2016, PSCo withdrew its application as it concluded that the litigation of the application would be contentious and, as structured, the framework would not address many of the concerns raised about the program by various intervenors. PSCo will continue to examine opportunities to mitigate price volatility for its customers.

PSCo – Advanced Grid Intelligence and Security — In August 2016, PSCo plans to file a request with the CPUC to approve a certificate of public convenience and necessity for implementation of its advanced grid initiative. The project incorporates installing advanced meters, implementing a combination of hardware and software applications to allow the distribution system to operate at a lower voltage (integrated volt-var optimization) and installing necessary communications infrastructure to implement this hardware. These major projects are expected to improve customer experience, enhance grid reliability and enable the implementation of new and innovative programs and rate structures. The estimated capital investment for the project is approximately $500 million, which is largely included in Xcel Energy's base capital forecast for 2016-2020. The project would be completed by 2021.

PSCo – Decoupling Filing — On July 12, 2016, PSCo filed a request with the CPUC to approve a partial decoupling mechanism for a five year period, effective in 2017. The proposed decoupling adjustment would allow PSCo to adjust annual revenues based on changes in weather normalized average use per customer for the residential and small C&I classes. The proposed mechanism is intended to improve PSCo's ability to collect base rate revenues in the event that average use per customer declines as a result of DSM, distributed generation and other energy saving programs. The proposed decoupling mechanism is symmetric and may result in potential refunds to customers if there were an increase in average use per customer. PSCo did not request that revenue be adjusted as a result of weather related sales fluctuations.

SPS – Texas 2016 Electric Rate Case — In February 2016, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the Public Utility Commission of Texas (PUCT) requesting an overall increase in annual base rate revenue of approximately $71.9 million, or 14.4 percent. The filing is based on a historic test year (HTY) ended Sept. 30, 2015, a requested ROE of 10.25 percent, an electric rate base of approximately $1.7 billion, and an equity ratio of 53.97 percent. In April 2016, SPS revised its requested rate increase to $68.6 million.

The following table summarizes the revised net request:

(Millions of Dollars)	Request
Capital expenditure investments	$ 38.9
Change in jurisdictional allocation factors	9.8
Changes in ROE and capital structure	11.6
Estimated rate case expenses	4.5
Other, net	3.8
Total	$ 68.6

Key dates in the procedural schedule are as follows:

- Intervenor direct testimony — Aug. 16, 2016;
- PUCT Staff direct testimony — Aug. 23, 2016;
- PUCT Staff and Intervenors' cross-rebuttal testimony — Sept. 7, 2016;
- SPS' rebuttal testimony — Sept. 9, 2016; and
- Hearings — Sept. 27 - Oct. 7, 2016.

SPS and various parties are having discussions regarding a potential settlement of the rate case. The final rates established at the end of the case are expected to be effective retroactive to July 20, 2016. A PUCT decision is expected in the first quarter of 2017.

SPS – New Mexico 2015 Electric Rate Case — In October 2015, SPS filed an electric rate case with the New Mexico Public Regulation Commission (NMPRC) seeking an increase in non-fuel base rates of $45.4 million. The proposed increase would be offset by a decrease in base fuel revenue of approximately $21.1 million. The rate filing is based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric rate base of approximately $734 million and an equity ratio of 53.97 percent.

In May 2016, SPS, the NMPRC Staff and all other parties filed a unanimous black-box stipulation that resolves all issues in the case. Under the stipulation, SPS will implement a non-fuel base rate increase of $23.5 million and a decrease in base fuel revenue of approximately $21.1 million. The decrease in base fuel revenue will be reflected in adjustments collected through the fuel and purchased power cost adjustment clause. The stipulation places no restriction on when SPS may file its next base rate case.

In July 2016, the hearing examiner issued a recommendation that the NMPRC approve the stipulation. The stipulation is subject to approval by the NMPRC and a decision on the settlement and implementation of final rates is expected in fall of 2016.

Note 5. Xcel Energy Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy Earnings Guidance — Xcel Energy's 2016 ongoing earnings guidance is $2.12 to $2.27 per share. Key assumptions related to 2016 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to decrease by approximately 0.5 percent.
- Weather normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase by $40 million to $50 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 1 percent from 2015 levels.
- Depreciation expense is projected to increase approximately $200 million over 2015 levels. Approximately $20 million of the increased depreciation expense and amortization will be recovered through the RDF rider (not included in the capital rider) in Minnesota.
- Property taxes are projected to increase approximately $40 million to $50 million over 2015 levels.
- Interest expense (net of allowance for funds used during construction (AFUDC) — debt) is projected to increase $40 million to $50 million over 2015 levels.
- AFUDC — equity is projected to increase approximately $0 million to $10 million from 2015 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

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 4 percent to 6 percent, based on ongoing 2015 EPS of $2.10, which was the mid-point of Xcel Energy's 2015 ongoing guidance range;
- 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.

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.

Note 6. Non-GAAP Reconciliation

Xcel Energy's reported earnings are prepared in accordance with GAAP. Xcel Energy's management believes that ongoing earnings, or GAAP earnings adjusted for certain items, reflect management's performance in operating the company and provides a meaningful representation of the underlying performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors and when communicating its earnings outlook to analysts and investors. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

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

(Thousands of Dollars)	Three Months Ended June 30 2016	Three Months Ended June 30 2015	Six Months Ended June 30 2016	Six Months Ended June 30 2015
Ongoing earnings	$ 196,795	$ 196,931	$ 438,107	$ 428,148
Loss on Monticello LCM/EPU project	—	—	—	(79,151)
GAAP earnings	$ 196,795	$ 196,931	$ 438,107	$ 348,997

Loss on Monticello LCM/EPU Project — In March 2015, the MPUC approved full recovery, including a return, on $415 million of the project costs, inclusive of AFUDC, but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment for years 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately $129 million, or $79 million net of tax, in the first quarter of 2015. Given the nature of this specific item, it has been excluded from ongoing earnings.

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

	Three Months Ended June 30	
	2016	**2015**
Operating revenues:		
Electric and natural gas	$ 2,483,041	$ 2,497,591
Other	16,808	17,543
Total operating revenues	2,499,849	2,515,134
Net income	$ 196,795	$ 196,931
Weighted average diluted common shares outstanding	509,490	508,074
Components of EPS — Diluted		
Regulated utility	$ 0.42	$ 0.42
Xcel Energy Inc. and other costs	(0.04)	(0.03)
Ongoing diluted EPS [a]	**0.39**	**0.39**
Loss on Monticello LCM/EPU project [b]	—	—
GAAP diluted EPS	**$ 0.39**	**$ 0.39**

	Six Months Ended June 30	
	2016	**2015**
Operating revenues:		
Electric and natural gas	$ 5,233,849	$ 5,438,450
Other	38,273	38,903
Total operating revenues	5,272,122	5,477,353
Net income	$ 438,107	$ 348,997
Weighted average diluted common shares outstanding	509,311	507,747
Components of EPS — Diluted		
Regulated utility	$ 0.93	$ 0.90
Xcel Energy Inc. and other costs	(0.07)	(0.05)
Ongoing diluted EPS	**0.86**	**0.85**
Loss on Monticello LCM/EPU project [b]	—	(0.16)
GAAP diluted EPS	**$ 0.86**	**$ 0.69**
Book value per share	$ 21.07	$ 20.26

(a) Amounts may not add due to rounding.
(b) See Note 6.