414 Nicollet Mall
Minneapolis, MN 55401

April 30, 2015

XCEL ENERGY
FIRST QUARTER 2015 EARNINGS REPORT

- Ongoing 2015 first quarter earnings per share were $0.46 compared with $0.52 in 2014;
- GAAP (generally accepted accounting principles) 2015 first quarter earnings per share were $0.30 compared with $0.52 per share in 2014; and
- Xcel Energy reaffirms 2015 ongoing earnings guidance of $2.00 to $2.15 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2015 first quarter GAAP earnings of $152 million, or $0.30 per share, compared with $261 million, or $0.52 per share, in the same period in 2014.

First quarter 2015 ongoing earnings, which exclude an adjustment for a charge related to the Monticello life cycle management/ extended power uprate project, were $0.46 per share compared with $0.52 per share for the first quarter of 2014. The decrease in ongoing earnings was largely attributable to the negative impact of weather. The extreme cold weather experienced in the first quarter of 2014 positively impacted earnings by approximately $0.05 per share. The weather in 2015 was closer to normal, resulting in a net negative variance when comparing periods. Other factors include higher depreciation, operating and maintenance expenses, property taxes and lower allowance for funds used during construction. These amounts were partially offset by earnings from higher electric margins due to new rates and riders in various jurisdictions.

"We had a solid first quarter, with progress on several fronts," said Chairman, President and Chief Executive Officer Ben Fowke. "We achieved regulatory certainty with rate case decisions in Colorado and Minnesota and resolution in connection with the Monticello nuclear facility prudence review. We increased our dividend 6.7 percent and raised our dividend growth target to 5 percent to 7 percent, reflecting the confidence we have in our business plan and our financial flexibility. Looking ahead, we fully expect to meet our O&M growth target of 2 percent or less and we are reaffirming our 2015 ongoing earnings guidance to $2.00 to $2.15 per share."

"We also received some welcome recognition recently that illustrates our long-standing commitment to environmental leadership, corporate governance and our nation's veterans," Fowke said. "The American Wind Energy Association named us the No. 1 provider of wind energy in the nation for the 11th consecutive year, *Forbes Magazine* put us on their 100 Most Trustworthy Companies in America list and *Military Times* once again recognized us as a Best for Vets Employer."

First quarter 2015 GAAP earnings included a $0.16 per share charge related to the Monticello nuclear facility life cycle management/extended power uprate project, which in total cost $748 million. In March 2015, the Minnesota Public Utility Commission approved full recovery, including a return, on $415 million of the project costs, inclusive of allowance for funds used during construction, 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.

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 March 31	
Diluted Earnings (Loss) Per Share	**2015**	**2014**
Ongoing diluted EPS	$ 0.46	$ 0.52
Loss on Monticello life cycle management/extended power uprate project [a]	(0.16)	—
GAAP diluted EPS	**$ 0.30**	**$ 0.52**

[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:	(800) 756-4697
International Dial-In:	(913) 312-9330
Conference ID:	2307788

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 April 30 through 10:59 p.m. CDT on May 2.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	2307788

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 2015 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 do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: 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 Inc. and its subsidiaries; 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; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the Nuclear Regulatory Commission; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Operations in Item 7 of Xcel Energy Inc.'s Form 10-K for the year ended Dec. 31, 2014; and the other risk factors listed from time to time by Xcel Energy in reports filed with the Securities and Exchange Commission (SEC), including Risk Factors in Item 1A and Exhibit 99.01 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2014.

For more information, contact:

Paul Johnson, Vice President, Investor Relations	(612) 215-4535
Noah Hauser, Director of Investor Relations	(612) 215-4559
For news media inquiries only, please call Xcel Energy Media Relations	(612) 215-5300
Xcel Energy internet address: www.xcelenergy.com	

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

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

	Three Months Ended March 31	
	2015	2014
Operating revenues		
Electric	$ 2,224,863	$ 2,301,710
Natural gas	715,996	879,688
Other	21,360	21,206
Total operating revenues	2,962,219	3,202,604
Operating expenses		
Electric fuel and purchased power	950,132	1,067,321
Cost of natural gas sold and transported	472,371	623,828
Cost of sales — other	10,049	9,129
Operating and maintenance expenses	585,830	560,143
Conservation and demand side management program expenses	53,805	77,546
Depreciation and amortization	273,098	245,943
Taxes (other than income taxes)	136,626	124,702
Loss on Monticello life cycle management/extended power uprate project	129,463	—
Total operating expenses	2,611,374	2,708,612
Operating income	350,845	493,992
Other income, net	3,161	3,201
Equity earnings of unconsolidated subsidiaries	7,776	7,438
Allowance for funds used during construction — equity	12,660	21,907
Interest charges and financing costs		
Interest charges — includes other financing costs of $5,698 and $5,792, respectively	144,940	139,094
Allowance for funds used during construction — debt	(6,144)	(9,548)
Total interest charges and financing costs	138,796	129,546
Income before income taxes	235,646	396,992
Income taxes	83,580	135,771
Net income	$ 152,066	$ 261,221
Weighted average common shares outstanding:		
Basic	506,983	499,523
Diluted	507,393	499,746
Earnings per average common share:		
Basic	$ 0.30	$ 0.52
Diluted	0.30	0.52
Cash dividends declared per common share	$ 0.32	$ 0.30

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 March 31	
Diluted Earnings (Loss) Per Share	**2015**	**2014**
Public Service Company of Colorado (PSCo)	$ 0.22	$ 0.24
NSP-Minnesota	0.16	0.21
NSP-Wisconsin	0.05	0.05
Southwestern Public Service Company (SPS)	0.04	0.04
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility	0.48	0.55
Xcel Energy Inc. and other	(0.02)	(0.03)
Ongoing diluted EPS	0.46	0.52
Loss on Monticello life cycle management (LCM)/extended power uprate (EPU) project [a]	(0.16)	—
GAAP diluted EPS	**$ 0.30**	**$ 0.52**

[a] See Note 6.

PSCo — PSCo's ongoing earnings decreased $0.02 per share for the first quarter of 2015. The positive impact of implementing the Clean Air Clean Jobs Act (CACJA) rider, effective Jan. 1, 2015, and the recognition of lower estimated electric earnings test refunds were offset by lower allowance for funds used during construction (AFUDC), higher property taxes, operating and maintenance (O&M) expenses, depreciation and the unfavorable impact of weather ($0.01 per share).

NSP-Minnesota — NSP-Minnesota's ongoing earnings decreased $0.05 per share for the first quarter of 2015. Higher revenue attributable to electric rate cases in North Dakota and South Dakota (interim, subject to refund) were more than offset by the impact of increases in depreciation and O&M expenses as well as unfavorable weather. The colder weather experienced in 2014 resulted in a $0.03 per share decrease when comparing periods. In the first quarter of 2015, NSP-Minnesota recorded electric revenue in Minnesota consistent with interim rates, which were implemented in January 2014, as the Minnesota Public Utilities Commission (MPUC) has not issued its final rate case order or ruled on its treatment of interim rates. A true-up reflecting an additional $10.5 million of first quarter revenue would be recorded later in the year, if the MPUC approves NSP-Minnesota's proposed treatment of the 2014 refund for interim rates.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings were flat for the first quarter of 2015. Lower O&M expenses and higher electric margins, primarily due to an electric rate increase, were offset by the unfavorable impact of weather ($0.01 per share) and higher depreciation.

SPS — SPS' ongoing earnings were flat for the first quarter of 2015. Higher electric rates in Texas and New Mexico were offset by higher depreciation and O&M expenses.

The following table summarizes significant components contributing to the changes in 2015 EPS compared with the same period in 2014:

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
2014 GAAP and ongoing diluted EPS	**$ 0.52**
Components of change — 2015 vs. 2014	
Higher electric margins	0.05
Lower conservation and demand side management (DSM) program expenses (offset by lower revenues)	0.03
Higher depreciation and amortization	(0.03)
Higher O&M expenses	(0.03)
Higher effective tax rate (ETR)	(0.02)
Lower AFUDC — equity	(0.02)
Lower natural gas margins	(0.01)
Higher taxes (other than income taxes)	(0.01)
Higher interest charges	(0.01)
Dilution from equity issued through the at-the-market program, direct stock purchase plan and benefit plans	(0.01)
2015 ongoing diluted EPS	**0.46**
Loss on Monticello LCM/EPU project [(a)]	(0.16)
2015 GAAP diluted EPS	**$ 0.30**

(a) See Note 6.

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 cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. 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.

There was no impact on sales in the first quarter of 2015 due to THI or CDD. The percentage (decrease) increase in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
HDD	(1.1)%	14.1%	(13.5)%

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

	Three Months Ended March 31		
	2015 vs. Normal	**2014 vs. Normal**	**2015 vs. 2014**
Retail electric	$ (0.001)	$ 0.031	$ (0.032)
Firm natural gas	(0.004)	0.018	(0.022)
Total	$ (0.005)	$ 0.049	$ (0.054)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2015:

	Three Months Ended March 31				
	Xcel Energy	**SPS**	**NSP-Wisconsin**	**PSCo**	**NSP-Minnesota**
Actual					
Electric residential [a]	(4.9)%	(3.1)%	(7.7)%	(3.3)%	(6.3)%
Electric commercial and industrial	—	1.9	1.5	0.4	(1.7)
Total retail electric sales	(1.5)	0.8	(1.6)	(0.8)	(3.1)
Firm natural gas sales	(10.1)	N/A	(9.3)	(9.6)	(11.1)

	Three Months Ended March 31				
	Xcel Energy	**SPS**	**NSP-Wisconsin**	**PSCo**	**NSP-Minnesota**
Weather-normalized					
Electric residential [a]	(0.5)%	2.0%	(1.2)%	(1.0)%	(0.7)%
Electric commercial and industrial	0.9	2.0	3.1	1.1	(0.4)
Total retail electric sales	0.5	1.9	1.7	0.4	(0.5)
Firm natural gas sales	2.9	N/A	6.5	2.0	3.9

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

Weather-normalized Electric Growth (Decline)

- SPS' commercial and industrial (C&I) growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area. Residential growth reflects an increased number of customers as well as greater use per customer.
- NSP-Wisconsin's electric sales growth was largely due to strong sales to large C&I customers primarily in the oil, gas and sand mining industries. Residential decline was primarily attributable to lower use per customer.
- PSCo's C&I growth was primarily due to expansion in the health care and technology services industries. Residential decrease was primarily the result of weaker use per customer, partially offset by customer growth.
- NSP-Minnesota's C&I electric sales declined as a result of lower use for large customers (primarily due to a decline in usage by the service industry), partially offset by an increase in the number of customers in both the small and large classes. Residential decrease was due to less use per customer, partially offset by increasing customer growth.

Weather-normalized Natural Gas Growth

- Across all natural gas service territories, increased natural gas sales were fueled by both customer growth and higher use per customer. Low natural gas prices and continued economic recovery drove gains from both residential and C&I customers. In addition, NSP-Minnesota and NSP-Wisconsin experienced growth from customers converting from propane to natural gas and customers in the sand mining industry.

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 March 31	
(Millions of Dollars)	**2015**	**2014**
Electric revenues	$ 2,225	$ 2,302
Electric fuel and purchased power	(950)	(1,067)
Electric margin	$ 1,275	$ 1,235

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

(Millions of Dollars)	**Three Months Ended March 31 2015 vs. 2014**
Non-fuel riders [(a)] [(b)]	$ 34
Retail rate increases [(b)] [(c)]	23
Earnings test refund	11
Transmission revenue, net of costs	7
NSP-Wisconsin fuel recovery	7
Estimated impact of weather	(25)
Conservation and DSM program revenues (offset by expenses)	(16)
Other, net	(1)
Total increase in electric margin	$ 40

(a) Increase relates primarily to the new CACJA rider in Colorado ($24 million), effective Jan. 1, 2015, and Transmission Cost Recovery (TCR) rider in Minnesota ($9 million).

(b) Non-fuel rider amounts for the CACJA rider in Colorado (allowed for in the settlement) positively impacted revenues and more than offset the base rate decrease. See Note 4 for further discussion.

(c) Increase due to rate proceedings in Texas, Minnesota, New Mexico, Wisconsin and North Dakota and the interim rates associated with the pending South Dakota case, subject to and net of an estimated provision for refund. These increases were slightly offset by a decline in Colorado retail base rates which occurred as a result of the recent CPUC decision.

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 to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

	Three Months Ended March 31	
(Millions of Dollars)	**2015**	**2014**
Natural gas revenues	$ 716	$ 880
Cost of natural gas sold and transported	(472)	(624)
Natural gas margin	$ 244	$ 256

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

(Millions of Dollars)	Three Months Ended March 31 2015 vs. 2014	
Estimated impact of weather	$	(17)
Conservation and DSM program revenues (offset by expenses)		(7)
Integrity rider (Colorado) and infrastructure rider (Minnesota), partially offset in expenses		7
Retail sales growth, excluding weather impact		4
Other, net		1
Total decrease in natural gas margin	$	(12)

O&M Expenses — O&M expenses increased $25.7 million, or 4.6 percent, for the first quarter of 2015 compared with the same period in 2014. O&M expenses were higher for the quarter, primarily due to the timing of planned maintenance and overhauls at a number of our generation facilities. We continue to expect that the change in annual O&M expense for 2015 to be within a range of 0 percent to 2 percent, consistent with our annual guidance assumptions.

(Millions of Dollars)	Three Months Ended March 31 2015 vs. 2014	
Plant generation costs	$	17
Nuclear plant operations		4
Employee benefits		4
Other, net		1
Total increase in O&M expenses	$	26

Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased $23.7 million, or 30.6 percent, for the first quarter of 2015 compared with the same period in 2014. The decrease was primarily attributable to lower electric and gas recovery rates at NSP-Minnesota and PSCo. Therefore, lower expenses are generally offset by lower revenues.

Depreciation and Amortization — Depreciation and amortization increased $27.2 million, or 11.0 percent, for the first quarter of 2015 compared with the same period in 2014. The increase was primarily attributed to normal system expansion and lower amortization of the excess depreciation reserve in Minnesota. See further discussion within Note 4.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $11.9 million, or 9.6 percent, for the first quarter of 2015 compared with the same period in 2014. The increase was due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC decreased $12.7 million for the first quarter of 2015 compared with the same period in 2014. The decrease was primarily due to the implementation of the CACJA rider on Jan. 1, 2015, facilitating earlier and alternative recovery of construction costs.

Interest Charges — Interest charges increased $5.8 million, or 4.2 percent, for the first quarter of 2015 compared with the same period in 2014. The increase was primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $52.2 million for the first quarter of 2015 compared with the same period in 2014. The decrease was primarily due to lower 2015 pretax earnings, partially offset by decreased permanent plant-related adjustments in 2015 and the successful resolution of a 2010-2011 IRS audit issue in 2014. The ETR was 35.5 percent for the first quarter of 2015 compared with 34.2 percent for the same period in 2014. The lower ETR for 2014 was primarily due to the adjustments referenced above.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	March 31, 2015	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.2	1%
Short-term debt	1.0	4
Long-term debt	11.5	50
Total debt	12.7	55
Common equity	10.2	45
Total capitalization	$ 22.9	100%

Credit Facilities — As of April 28, 2015, 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.	$ 1,000.0	$ 513.0	$ 487.0	$ 0.6	$ 487.6
PSCo	700.0	170.5	529.5	1.0	530.5
NSP-Minnesota	500.0	83.4	416.6	0.6	417.2
SPS	400.0	180.0	220.0	0.4	220.4
NSP-Wisconsin	150.0	85.0	65.0	0.4	65.4
Total	$ 2,750.0	$ 1,031.9	$ 1,718.1	$ 3.0	$ 1,721.1

(a) These credit facilities expire in October 2019.

(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).

As of April 28, 2015, the following represents the credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries:

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

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.

During 2015, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately $500 million of senior unsecured bonds;
- PSCo plans to issue approximately $250 million of first mortgage bonds;
- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds;
- SPS plans to issue approximately $250 million of first mortgage bonds; and
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds.

Xcel Energy does not anticipate issuing any additional equity, beyond its dividend reinvestment program and benefit programs, for 2015-2019, based on its current capital expenditure plan. 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 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the MPUC. The rate case was based on a requested return on equity (ROE) of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015. The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately $193 million, or 6.9 percent, in 2014 and an additional $98 million, or 3.5 percent, in 2015. The request included a proposed rate moderation plan for 2014 and 2015. In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund.

In 2014, NSP-Minnesota revised its requested rate increase to $115.3 million for 2014 and to $106.0 million for 2015, for a total combined unadjusted increase of $221.3 million.

In December 2014, the administrative law judge (ALJ) issued her recommendations in the NSP-Minnesota electric rate case. NSP-Minnesota estimated that her recommendations would have resulted in a rate increase of $69.1 million in 2014 and an incremental rate increase of $122.4 million in 2015. In addition, she recommended an ROE of 9.77 percent and an equity ratio of 52.5 percent.

On March 26, 2015, the MPUC voted to approve a 2014 rate increase and a 2015 step increase. NSP-Minnesota estimates the total rate increase to be approximately $168 million, or 6.1 percent, based on a 9.72 percent ROE and 52.50 percent equity ratio. The MPUC largely approved the ALJ's recommendations and the excess depreciation reserve utilization of 50 percent, 30 percent and 20 percent in 2014, 2015, and 2016, respectively. The MPUC did not adopt NSP-Minnesota's 2016 rate case avoidance proposal. NSP-Minnesota is initiating the preparation of its 2016 rate case. NSP-Minnesota will evaluate how best to proceed including whether proposed legislation could provide alternative approaches, whether rate moderation is available and whether to propose a single or multi-year request.

The following table reconciles NSP-Minnesota's original request to the MPUC's March 26, 2015 verbal decision, including the estimated ongoing impact of their March 6, 2015 verbal decision in the Monticello Prudence Review on the Minnesota retail electric jurisdiction:

2014 Rate Request (Millions of Dollars)	NSP-Minnesota	ALJ	MPUC Decision
NSP-Minnesota's filed rate request	$ 192.7	$ 192.7	$ 192.7
Sales forecast (with true-up to 12 months of actual weather-normalized sales)	(38.5)	(38.5)	(38.5)
ROE	—	(28.4)	(31.9)
Monticello EPU cost recovery	(12.2)	(31.3)	(37.6)
Property taxes (with true-up to actual 2014 accruals)	(13.2)	(13.2)	(13.2)
Prairie Island EPU cost recovery	(5.1)	(5.1)	(5.1)
Health care, pension and other benefits	(1.9)	(1.9)	(3.0)
Other, net	(6.5)	(5.2)	(5.3)
Total 2014	$ 115.3	$ 69.1	$ 58.1

2015 Rate Request (Millions of Dollars)	NSP-Minnesota	ALJ	MPUC Decision
NSP-Minnesota's filed rate request	$ 98.5	$ 98.5	$ 98.5
Monticello EPU cost recovery	11.7	29.1	35.4
Depreciation / retirements	—	—	(0.5)
Property taxes	(3.3)	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)	(11.1)
U.S. Department of Energy settlement proceeds	10.1	10.1	10.1
Emission chemicals	(1.6)	(1.6)	(1.6)
Other, net	1.7	0.7	0.2
Total 2015 step increase - prior to Monticello EPU cost disallowance	$ 106.0	$ 122.4	$ 127.7
Total for 2014 and 2015 step increase - prior to Monticello EPU cost disallowance	$ 221.3	$ 191.5	$ 185.8
Monticello EPU cost disallowance - ongoing impact	—	—	(18.2)
Total for 2014 and 2015 step increase - including Monticello EPU cost disallowance	$ 221.3	$ 191.5	$ 167.6

The MPUC also approved a full revenue decoupling three-year pilot with a 3 percent cap on base revenue for the residential and small C&I classes, based on actual sales, effective Jan. 1, 2016. The decoupling mechanism would eliminate the impact of weather variability on electric sales for these classes. NSP-Minnesota can seek to recover amounts over the cap provided it can show that its demand-side management and/or other initiatives were a substantial contributing factor to the declining energy consumption and that other non-conservation factors were not the primary factors for the under-recovery.

The MPUC made no determination on NSP-Minnesota's interim rate refund proposal. There are currently two proposals in the case regarding the potential refund for interim rates for 2014 and 2015. NSP-Minnesota has requested that the MPUC treat the multi-year case as a single period and net the two-year period for any potential refund/surcharge that could occur when final rates are established. The Minnesota Department of Commerce identified an alternative option that views each year of the multi-year case separately, which would result in lower 2015 revenues by approximately $3.5 million per month between Jan. 1, 2015 and the date that final rates are determined. The final order is expected to be issued May 8, 2015. NSP-Minnesota filed the initial parts of a compliance filing calculating the final authorized rates in April 2015 and plans to file the remaining portions during May 2015. The MPUC is expected to rule on interim rates after the comment period for the compliance filing.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 megawatts (MW). Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately $320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

On March 6, 2015, the MPUC voted to allow for full recovery, including a return, on approximately $415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment over the remaining life of the plant. Further, the MPUC determined that only 50 percent of the investment was considered used and useful for 2014. As a result of these determinations and assuming the other state commissions within the NSP System jurisdictions adopt the MPUC's decisions, Xcel Energy recorded an estimated pre-tax loss of $129 million in the first quarter of 2015. The remaining book value of the Monticello project represents the present value of the estimated future cash flows allowed for by the MPUC.

In addition, the decision would reduce the 2015 revenue requirement and pre-tax income for Xcel Energy (assuming other state commissions adopt the MPUC decision) and the Minnesota retail electric jurisdiction as follows:

(Millions of Dollars)	Revenue	Pre-tax Income [(a)]
Xcel Energy	$ 25	$ 16
Minnesota retail electric jurisdiction	18	12

(a) Pre-tax income reflects the net impact of the reductions in revenue and depreciation expense.

Review of the final written order, which is anticipated in the second quarter of 2015, could impact NSP-Minnesota's calculations. NSP-Minnesota will have the ability to file for reconsideration.

NSP-Minnesota – South Dakota 2015 Electric Rate Case — In June 2014, NSP-Minnesota filed a request with the South Dakota Public Utilities Commission to increase South Dakota electric rates by $15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. The request is based on a 2013 historic test year (HTY) adjusted for certain known and measurable changes for 2014 and 2015, a requested ROE of 10.25 percent, an average rate base of $433.2 million and an equity ratio of 53.86 percent. This request reflects NSP-Minnesota's proposal to move recovery of approximately $9.0 million for certain TCR rider and Infrastructure rider projects to base rates.

Interim rates of $15.6 million, subject to refund, went into effect in January 2015. At this time, the parties are in settlement discussion and further procedure scheduling may be established, as necessary. Final rates are anticipated to be effective mid-2015.

NSP-Minnesota – Courtenay Wind Farm — In 2013, NSP-Minnesota signed a purchase power agreement with a developer for the Courtenay wind farm, a 200 megawatt project in North Dakota. Since that time, the developer is seeking to exit the project due to a lack of financial wherewithal. Courtenay was originally scheduled for commercial operation in 2014, but significant site construction on the project has not commenced. As a result, NSP-Minnesota has negotiated an agreement to acquire the development rights for the project and is seeking to preserve other benefits of the project by curing the developer's default under a generator interconnection agreement, which is critical to timely construction of the project, and which we expect will be resolved between the parties or by the FERC by the end of May. After regulatory approval of the transaction, NSP-Minnesota plans to move forward with construction and will ultimately own the facility as part of rate base. In May 2015, NSP-Minnesota anticipates filing for expedited regulatory approval in Minnesota and North Dakota, so that construction can begin in late summer. The total construction cost of the project is estimated to be approximately $300 million with project completion by the end of 2016. Courtenay is not currently included in Xcel Energy's five-year capital forecast. Xcel Energy does not expect to issue any additional equity to finance the project.

PSCo – Colorado 2014 Electric Rate Case — In 2014, PSCo filed an electric rate case with the Colorado Public Utilities Commission (CPUC) requesting an increase in annual revenue of approximately $136.0 million, or 4.83 percent. The requested 2015 rate increase reflected approximately $100.9 million (subsequently updated to $98.7 million) for recovery of costs associated with the CACJA project. The case also requested the initiation of a CACJA rider for 2016 and 2017, which was anticipated to increase revenue recovery by approximately $34.2 million in 2016 and then decline to approximately $29.9 million in 2017.

In December 2014, PSCo filed rebuttal testimony, revising its requested rate increase to $107.2 million, or 3.79 percent, reflecting an ROE of 10.25 percent and updated information for both the sales and property tax forecasts. PSCo also proposed to recover all costs associated with the CACJA project through the rider beginning in 2015.

In February 2015, the CPUC approved a settlement agreement with rates effective on Feb. 13, 2015. This agreement results in an overall 2015 revenue increase of approximately $53.3 million, or 1.87 percent. Key terms of the agreement include the following:

- The settlement is based on a 2013 HTY, an ROE of 9.83 percent and an equity ratio of 56 percent;
- The implementation of a forward-looking CACJA rider of approximately $97.0 million for 2015 with step increases of $17.7 million and $14.5 million for 2016 and 2017, respectively, effective Jan. 1, 2015;
- A forward-looking transmission cost adjustment (TCA) rider of approximately $15.6 million, effective Feb. 13, 2015;
- Establishment of tracking mechanisms for pension expense and property taxes; and
- An earnings test for 2015 through 2017, under which PSCo and customers would share in any earnings on a 50/50 basis if the ROE recognized falls between 9.84 percent and 10.48 percent.

The components of the overall 2015 revenue increase are as follows:

(Millions of Dollars)	Approved Settlement
Total base rate decrease	$ (39.4)
CACJA rider mechanism	97.0
TCA rider mechanism	15.6
Transfer from TCA rider to base rates	(19.9)
Total revenue increase	**$ 53.3**

In addition to the revenue increase of $53.3 million, including the impact of the riders, PSCo estimates that it will defer approximately $3.1 million of additional expenses in 2015 as a result of the settlement.

PSCo – Colorado 2015 Multi-Year Gas Rate Case — On March 3, 2015, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas base rates by $40.5 million, or 3.5 percent, in 2015, with subsequent step increases of $7.6 million, or 0.7 percent, in 2016 and $18.1 million, or 1.5 percent, in 2017.

The request is based on an HTY ended June 30, 2014 adjusted for known and measurable expenses and capital additions for each of the subsequent periods in the multi-year plan and an equity ratio of 56 percent. The rate case requests a ROE of 10.1 percent for 2015 and 2016 and 10.3 percent for 2017, and a rate base of $1.26 billion for 2015, $1.31 billion for 2016 and $1.36 billion for 2017.

PSCo is also proposing a stay-out provision, in which PSCo would not request implementation of new rates prior to January 2018, and to implement an earnings test for 2016 through 2017. Under the earnings test, PSCo and customers would share in any earnings on a 50/50 basis if the ROE recognized falls between 10.2 percent and 10.6 percent in 2016, and between 10.4 percent and 10.8 percent in 2017.

In addition, PSCo requested an extension of its pipeline system integrity adjustment (PSIA) rider through 2020 to recover costs associated with its pipeline integrity efforts, including accelerated system renewal projects. If the PSIA rider is not extended by Dec. 31, 2015, such costs would be included in base rates. The request to extend and modify the PSIA rider has an expected negative revenue impact of approximately $0.1 million in 2015 and would provide incremental revenue of $21.7 million for 2016 and $21.2 million for 2017. If PSCo's proposal is accepted, PSIA revenue is projected to be $67.0 million in 2015, $88.7 million in 2016, and $109.9 million in 2017.

The following table summarizes the request:

(Millions of Dollars)	2015	2016 Step	2017 Step
Net plant and plant related expenses	$ 24.4	$ 12.4	$ 12.0
O&M expenses	23.9	(5.2)	0.6
Property and payroll taxes	4.7	2.6	4.0
ROE	4.5	—	2.4
Capital structure	(1.0)	—	0.1
Sales forecast	(17.1)	(2.2)	(1.0)
Other, net	1.1	—	—
Total base rate increase	40.5	7.6	18.1
Incremental PSIA rider revenues	(0.1)	21.7	21.2
Total revenue impact	$ 40.4	$ 29.3	$ 39.3

In March 2015, the CPUC referred the proceeding to an ALJ. A CPUC decision, as well as implementation of final rates, are anticipated in the fourth quarter of 2015.

PSCo – Annual Electric Earnings Test — As part of an annual earnings test, PSCo must share with customers a portion of any annual earnings that exceed PSCo's authorized ROE threshold of 10 percent for 2012 through 2014. On April 30, 2015, PSCo expects to file a tariff for the 2014 earnings test with the CPUC proposing a refund obligation of $66.5 million to electric customers.

In February 2015, in the Colorado 2014 Electric Rate Case, the CPUC approved an annual earnings test, in which PSCo shares with customers earnings that exceed the authorized ROE threshold of 9.83 percent for 2015 through 2017. The current estimate of the 2015 earnings test, based on annual forecasted information, did not result in the recognition of a liability as of March 31, 2015.

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric, non-fuel rate case in Texas seeking an overall increase in annual revenue of approximately $64.8 million, or 6.7 percent. The filing was based on an HTY ended June 2014, adjusted for known and measurable changes, an ROE of 10.25 percent, an electric rate base of approximately $1.6 billion and an equity ratio of 53.97 percent. In March 2015, SPS revised its requested increase to $58.9 million based on updated information.

As part of its request, SPS is seeking a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of $392 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014.

The following table summarizes the net request:

(Millions of Dollars)	Request
Investment for capital expenditures — post-test year adjustments	$ 23.7
Depreciation expense	13.9
Wholesale load reductions	12.0
Purchased power capacity costs	3.2
Other, net	6.1
Total	$ 58.9

In April 2015, a revised procedural schedule was established. The next steps are expected to be as follows:

- Intervenor Direct Testimony — May 15, 2015;
- Staff Direct Testimony — May 22, 2015;
- Staff and Intervenor Cross-Rebuttal Testimony — June 8, 2015;
- Rebuttal Testimony — June 10, 2015; and
- Evidentiary Hearing — June 24, 2015.

The parties have agreed the rates will be effective June 11, 2015. A PUCT decision is anticipated in the second half of 2015.

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

Xcel Energy Earnings Guidance — Xcel Energy's 2015 ongoing earnings guidance is $2.00 to $2.15 per share. Key assumptions related to 2015 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 increase approximately 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to increase 0 percent to 1 percent.
- Capital rider revenue is projected to increase by $155 million to $165 million over 2014 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2014 levels.
- Depreciation expense is projected to increase $130 million to $150 million over 2014 levels.
- Property taxes are projected to increase approximately $60 million to $70 million over 2014 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2014 levels.
- AFUDC — equity is projected to decline approximately $30 million to $40 million from 2014 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 508 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 weather-normalized, ongoing 2014 EPS of $2.00;
- 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):

	Three Months Ended March 31	
(Thousands of Dollars)	**2015**	**2014**
Ongoing earnings	$ 231,217	$ 261,221
Loss on Monticello LCM/EPU project	(79,151)	—
GAAP earnings	$ 152,066	$ 261,221

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 2015. Given the nature of this specific item, it has been excluded from ongoing earnings. See Note 4.

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

	Three Months Ended March 31	
	2015	2014
Operating revenues:		
Electric and natural gas	$ 2,940,859	$ 3,181,398
Other	21,360	21,206
Total operating revenues	2,962,219	3,202,604
Net income	$ 152,066	$ 261,221
Weighted average diluted common shares outstanding	507,393	499,746
Components of EPS — Diluted		
Regulated utility	$ 0.48	$ 0.55
Xcel Energy Inc. and other costs	(0.02)	(0.03)
Ongoing diluted EPS	**0.46**	**0.52**
Loss on Monticello LCM/EPU project [a]	(0.16)	—
GAAP diluted EPS	**$ 0.30**	**$ 0.52**
Book value per share	$ 20.16	$ 19.45

[a] See Note 6.