Xcel Energy Second Quarter 2014 Earnings Report

- GAAP (generally accepted accounting principles) 2014 second quarter diluted earnings per share were $0.39 compared with $0.40 per share in 2013.
- Xcel Energy reaffirms 2014 ongoing earnings guidance of $1.90 to $2.05 per share.

July 31, 2014 06:00 AM Eastern Daylight Time

MINNEAPOLIS--(BUSINESS WIRE)--Xcel Energy Inc. (NYSE:XEL) today reported 2014 second quarter GAAP earnings of $195 million, or $0.39 per share, compared with $197 million, or $0.40 per share, in the same period in 2013.

Electric and gas margins rose in the second quarter of 2014 primarily driven by new rates in various jurisdictions. This positive factor, along with lower interest expense, was more than offset by higher operating and maintenance expenses, property taxes, and depreciation and amortization expense as well as less favorable weather.

“Our second quarter financial results were in line with our projections and we are pleased with our performance through the first six months,” stated Chairman, President and Chief Executive Officer Ben Fowke. “Notably, we are encouraged to see the continuation of better-than-expected weather-normalized sales growth. In addition, our year-to-date operating and maintenance expenses are consistent with our plan and we are on track to meet our guidance of a 2 to 3 percent annual increase over 2013 levels.

“During the second quarter, we filed rate cases in Colorado, Wisconsin and South Dakota and continued settlement discussions in Texas. We also received initial recommendations from the intervenors for the Minnesota electric rate case and the Minnesota Department of Commerce regarding the Monticello prudence review. We believe our request in Minnesota is warranted and the costs associated with Monticello uprate and life extension project were prudent. We will continue to provide support for our positions and expect to reach constructive outcomes in each of these regulatory proceedings.

“We are reaffirming our 2014 ongoing earnings guidance of $1.90 to $2.05 per share, which is based on several key assumptions, including constructive outcomes of our regulatory proceedings,” said Fowke.

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

US Dial-In:	(877) 941-8609
International Dial-In:	(480) 629-9692
Conference ID:	4687079

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 Investors. If you are unable to participate in the live event, the call will be available for replay from 1:00 p.m. CDT on July 31 through 11:59 p.m. CDT on Aug. 1.

Replay Numbers

US Dial-In:	(800) 406-7325
International Dial-In:	(303) 590-3030
Access Code:	4687079#

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 2014 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; 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; 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, 2013 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

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	
	2014	**2013**	**2014**	**2013**
Operating revenues				
Electric	$ 2,297,638	$ 2,219,877	$ 4,599,348	$ 4,312,073
Natural gas	369,127	341,321	1,248,815	1,010,917
Other	18,331	17,715	39,537	38,772
Total operating revenues	2,685,096	2,578,913	5,887,700	5,361,762
Operating expenses				
Electric fuel and purchased power	1,041,322	1,011,044	2,108,643	1,936,087
Cost of natural gas sold and transported	210,901	188,765	834,729	628,140
Cost of sales — other	7,642	7,881	16,771	16,292
Operating and maintenance expenses	585,604	562,557	1,145,747	1,091,788
Conservation and demand side management program expenses	70,834	60,445	148,380	124,477
Depreciation and amortization	255,307	243,934	501,250	492,640
Taxes (other than income taxes)	116,278	102,051	240,980	215,478
Total operating expenses	2,287,888	2,176,677	4,996,500	4,504,902
Operating income	397,208	402,236	891,200	856,860
Other income, net	82	413	3,283	4,335
Equity earnings of unconsolidated subsidiaries	7,811	7,529	15,249	15,106
Allowance for funds used during construction — equity	23,608	22,109	45,515	41,863

Interest charges and financing costs				
Interest charges — includes other financing costs of				
$5,614, $12,229, $11,406 and $18,038, respectively	139,400	146,853	278,494	286,484
Allowance for funds used during construction — debt	(10,113)	(10,316)	(19,661)	(19,074)
Total interest charges and financing costs	129,287	136,537	258,833	267,410
Income before income taxes	299,422	295,750	696,414	650,754
Income taxes	104,258	98,893	240,029	217,327
Net income	$ 195,164	$ 196,857	$ 456,385	$ 433,427
Weighted average common shares outstanding:				
Basic	503,272	497,747	501,408	493,786
Diluted	503,456	498,036	501,612	494,303
Earnings per average common share:				
Basic	$ 0.39	$ 0.40	$ 0.91	$ 0.88
Diluted	0.39	0.40	0.91	0.88
Cash dividends declared per common share	$ 0.30	$ 0.28	$ 0.60	$ 0.55

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 per share (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. Diluted EPS by subsidiary is a financial measure not recognized under GAAP and is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary 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 earnings results. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. 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	**2014**	**2013**	**2014**	**2013**
Public Service Company of Colorado (PSCo)	$ 0.18	$ 0.20	$ 0.41	$ 0.43
NSP-Minnesota	0.15	0.16	0.37	0.37
Southwestern Public Service Company (SPS)	0.06	0.05	0.09	0.08
NSP-Wisconsin	0.02	0.02	0.07	0.06
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility	0.42	0.44	0.96	0.96
Xcel Energy Inc. and other	(0.03)	(0.04)	(0.05)	(0.08)
GAAP diluted EPS	**$ 0.39**	**$ 0.40**	**$ 0.91**	**$ 0.88**

PSCo — PSCo's earnings decreased $0.02 per share for the second quarter and six months ended June 30, 2014. Higher electric and natural gas rates and weather-normalized sales growth were offset by increased property taxes, depreciation, accruals associated with electric earnings test refund obligations as well as the impact of weather. See Note 4 for further discussion of rates and regulation.

NSP-Minnesota — NSP-Minnesota's earnings decreased $0.01 per share for the second quarter of 2014 and were flat year-to-date. Electric rate increases in Minnesota (interim, subject to refund) and North Dakota, lower depreciation expense, weather-normalized sales growth and the favorable year-over-year impact of weather were offset by higher operating and maintenance (O&M) expenses, lower allowance for funds used during construction (AFUDC) and higher property taxes.

SPS — SPS' earnings increased $0.01 per share for the second quarter and six months ended June 30, 2014. The positive impact of higher electric rates in Texas and New Mexico and weather-normalized sales growth were partially offset by increased O&M expenses and depreciation.

NSP-Wisconsin — NSP-Wisconsin's earnings were flat for the second quarter of 2014 and increased $0.01 per share year-to-date. Higher electric and natural gas margins, due to an electric rate increase effective in January 2014, and weather-normalized sales growth were partially offset by higher O&M expenses.

The following table summarizes significant components contributing to the changes in 2014 EPS compared with the same period in 2013, which are discussed in more detail later in the release:

Diluted Earnings (Loss) Per Share	**Three Months Ended June 30**	**Six Months Ended June 30**
2013 GAAP diluted EPS	**$ 0.40**	**$ 0.88**
Components of change — 2014 vs. 2013		
Higher electric margins	0.06	0.14

Higher natural gas margins	0.01	0.04
Lower interest charges	0.01	0.01
Higher AFUDC — equity	—	0.01
Higher O&M expenses	(0.03)	(0.07)
Higher taxes (other than income taxes)	(0.02)	(0.03)
Higher conservation and demand side management (DSM) program expenses	(0.01)	(0.03)
Higher depreciation and amortization	(0.01)	(0.01)
Dilution from equity issued through the at-the-market (ATM) program, direct stock purchase plan and benefit plans	—	(0.01)
Other, net	(0.02)	(0.02)
2014 GAAP diluted EPS	**$ 0.39**	**$ 0.91**

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, conversely, 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, from both an energy and demand perspective.

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, and 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 the time period used by the regulator in establishing estimated volumes in the rate setting process. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales as defined above to derive the amount of demand associated with the weather impact.

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

	Three Months Ended June 30			**Six Months Ended June 30**		
	2014 vs. Normal	**2013 vs. Normal**	**2014 vs. 2013**	**2014 vs. Normal**	**2013 vs. Normal**	**2014 vs. 2013**
HDD	4.5 %	22.5 %	(16.6)%	12.3 %	7.2 %	3.7 %
CDD	0.6	52.2	(29.6)	1.0	51.8	(28.9)
THI	9.3	6.6	7.1	8.4	6.5	7.1

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**		
2014 vs.	**2013 vs.**	**2014 vs.**	**2014 vs.**	**2013 vs.**	**2014 vs.**

	Normal	Normal	2013	Normal	Normal	2013
Retail electric	$ 0.002	$ 0.027	$ (0.025)	$ 0.034	$ 0.031	$ 0.003
Firm natural gas	0.001	0.007	(0.006)	0.019	0.016	0.003
Total	$ 0.003	$ 0.034	$ (0.031)	$ 0.053	$ 0.047	$ 0.006

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2014:

	Three Months Ended June 30				
	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	Xcel Energy
Actual					
Electric residential	0.2 %	1.7 %	(5.0)%	(2.8)%	(2.0)%
Electric commercial and industrial	(0.4)	4.3	(1.5)	3.1	0.4
Total retail electric sales	(0.3)	3.6	(2.5)	1.9	(0.2)
Firm natural gas sales	0.3	(0.8)	(6.0)	N/A	(3.7)

	Three Months Ended June 30				
	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	Xcel Energy
Weather-normalized					
Electric residential	2.0 %	0.8 %	1.1 %	1.0 %	1.4 %
Electric commercial and industrial	(0.1)	4.0	1.1	3.7	1.5
Total retail electric sales	0.4	3.1	1.1	3.2	1.4

Firm natural gas sales	7.5	14.6	8.5	N/A	8.6

	Six Months Ended June 30				
	NSP-Minnesota	**NSP-Wisconsin**	**PSCo**	**SPS**	**Xcel Energy**
Actual					
Electric residential	3.2 %	5.4 %	(1.8)%	3.7 %	1.6 %
Electric commercial and industrial	1.1	5.4	(0.1)	3.8	1.7
Total retail electric sales	1.7	5.4	(0.5)	3.6	1.7
Firm natural gas sales	12.7	13.8	(1.9)	N/A	3.7

	Six Months Ended June 30				
	NSP-Minnesota	**NSP-Wisconsin**	**PSCo**	**SPS**	**Xcel Energy**
Weather-normalized					
Electric residential	1.2 %	0.7 %	1.2 %	2.0 %	1.3 %
Electric commercial and industrial	0.7	4.3	1.1	4.1	1.9
Total retail electric sales	0.8	3.2	1.2	3.6	1.7
Firm natural gas sales	3.7	4.7	5.7	N/A	5.0

Weather-normalized Electric Growth

- NSP-Minnesota’s electric residential sales growth is primarily related to outages from severe storms experienced during the second quarter of 2013, which served to lower sales in that period and, in turn, increased year-over-year sales.

- NSP-Wisconsin's electric commercial and industrial (C&I) sales growth was primarily related to certain energy sector and manufacturing customers.
- PSCo's electric residential sales growth reflects an increased number of customers. Several large mining and manufacturing customers drove C&I growth.
- SPS' C&I growth was the result of continued expansion of oilfield development in southeast New Mexico.

Weather-normalized Gas Growth

- Across the gas service territories, strong sales were experienced during the first half of the year, which continued the trend that began in the last half of 2013. As normal weather conditions are typically defined as a 30-year average of actual historical weather conditions, significant weather fluctuations in periods of low demand may result in large percentage changes on small volumes. Extreme weather variations and additional factors such as windchill and cloud cover may not be fully reflected.

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 little 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)	**2014**	**2013**	**2014**	**2013**
Electric revenues	$ 2,298	$ 2,220	$ 4,599	$ 4,312
Electric fuel and purchased power	(1,041)	(1,011)	(2,109)	(1,936)
Electric margin	$ 1,257	$ 1,209	$ 2,490	$ 2,376

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

(Millions of Dollars)	Three Months Ended June 30 2014 vs. 2013	Six Months Ended June 30 2014 vs. 2013
Retail rate increases [a]	$ 38	$ 73
Conservation and DSM program revenues (offset by expenses)	12	25
Transmission revenue, net of costs	10	21
Retail sales growth, excluding weather impact	7	20
Non-fuel riders	17	19
Estimated impact of weather	(19)	3
PSCo earnings test refund obligations	(9)	(20)
Firm wholesale	(9)	(13)
Other, net	1	(14)
Total increase in electric margin	$ 48	$ 114

[a] Retail rates implemented in 2014 include interim rates in Minnesota, subject to refund, and final rates for Colorado, Wisconsin, New Mexico and North Dakota. In addition, retail rates in Texas were implemented in the second quarter of 2013. See Note 4 for further discussion.

Natural Gas Margin — The cost of natural gas 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 June 30		Six Months Ended June 30	
(Millions of Dollars)	**2014**	**2013**	**2014**	**2013**
Natural gas revenues	$ 369	$ 341	$ 1,249	$ 1,011
Cost of natural gas sold and transported	(211)	(189)	(835)	(628)
Natural gas margin	$ 158	$ 152	$ 414	$ 383

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

(Millions of Dollars)	**Three Months Ended June 30 2014 vs. 2013**	**Six Months Ended June 30 2014 vs. 2013**
Retail rate increase, net of refund (Colorado)	$ 7	$ 16
Retail sales growth	3	6
Pipeline system integrity adjustment rider (Colorado), partially offset in O&M expenses	—	4
Estimated impact of weather	(5)	3
Other, net	1	2

Total increase in natural gas margin	$	6	$	31

O&M Expenses — O&M expenses increased $23.0 million, or 4.1 percent, for the second quarter of 2014 and $54.0 million, or 4.9 percent, for the six months ended June 30, 2014. The year-to-date increase in O&M expense is partially due to the timing of a prior year nuclear outage (i.e., amortization of the 2013 Monticello outage began in July 2013). Xcel Energy continues to project annual O&M expenses will increase 2 percent to 3 percent for 2014.

(Millions of Dollars)	Three Months Ended June 30 2014 vs. 2013		Six Months Ended June 30 2014 vs. 2013	
Nuclear plant operations and amortization	$	15	$	27
Electric and gas distribution expenses		3		13
Plant generation costs		6		6
Transmission costs		3		6
Other, net		(4)		2
Total increase in O&M expenses	$	23	$	54

- Nuclear plant operations and amortization cost increases were primarily related to the amortization of the 2013 Monticello outage costs, as well as initiatives designed to improve the operational efficiencies of the plants;
- Electric and gas distribution expenses were primarily driven by increased maintenance activities (e.g., vegetation management) and repairs and amounts related to pipeline system integrity;

- Plant generation costs were driven by the timing of overhauls; and
- Transmission costs increased as a result of higher substation maintenance and repairs.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $10.4 million, or 17.2 percent, for the second quarter of 2014 and $23.9 million, or 19.2 percent, for the six months ended June 30, 2014. These increases were primarily attributable to higher electric recovery rates at NSP-Minnesota and PSCo. Conservation costs are recovered from customers and expensed on a kilowatt hour basis. As such, increased sales due to cold winter temperatures or hot summer temperatures will increase revenues and expenses.

Depreciation and Amortization — Depreciation and amortization increased $11.4 million, or 4.7 percent, for the second quarter of 2014 and $8.6 million, or 1.7 percent, year-to-date. The increases were primarily attributed to normal system expansion, partially offset by additional accelerated amortization of the excess depreciation reserve associated with certain Minnesota assets. See further discussion within Note 4.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $14.2 million, or 13.9 percent, for the second quarter of 2014 and $25.5 million, or 11.8 percent, for the six months ended June 30, 2014. The increases were due to higher property taxes primarily in Minnesota and Colorado.

AFUDC, Equity and Debt — AFUDC increased $1.3 million for the second quarter of 2014 and $4.2 million year-to-date. The increases were due to construction related to the Clean Air Clean Jobs Act (CACJA) project and the expansion of transmission facilities, partially offset by the reduction caused by the portion of the Monticello life cycle management (LCM)/extended power uprate (EPU) placed in service in July 2013.

Interest Charges — Interest charges decreased $7.5 million, or 5.1 percent, for the second quarter of 2014 and $8.0 million, or 2.8 percent, for the six months ended June 30, 2014. The decreases were primarily due to refinancings at lower interest rates and the write off of $6.3 million of unamortized debt expense associated with the calling of junior subordinated notes in May 2013. These positive factors were partially offset by higher long-term debt levels in the current period.

***Income Taxes* —** Income tax expense increased $5.4 million for the second quarter of 2014. The increase in income tax expense was primarily due to higher pretax earnings in 2014, decreased permanent plant-related adjustments in 2014, recognition of research and experimentation credits in 2013 and a tax benefit for a carryback claim related to 2013. These were partially offset by a tax benefit for an income exclusion in 2014. The effective tax rate (ETR) was 34.8 percent for the second quarter of 2014, compared to 33.4 percent for the second quarter of 2013 due to these adjustments.

Income tax expense increased $22.7 million for the first six months of 2014. The increase in income tax expense was primarily due to higher pretax earnings in 2014, recognition of research and experimentation credits in 2013 and a tax benefit for a carryback claim related to 2013. These were partially offset by the successful resolution of a 2010-2011 Internal Revenue Service audit issue in 2014. The ETR was 34.5 percent for the first six months of 2014, compared to 33.4 percent for the first six months of 2013 due to these adjustments.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	June 30, 2014	Percentage of Total Capitalization
Short-term debt	$ 0.8	4 %
Long-term debt	11.8	52
Total debt	12.6	56

Common equity	9.9	44
Total capitalization	$ 22.5	100 %

Credit Facilities — As of July 29, 2014, 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.	$ 800.0	$ 433.0	$ 367.0	$ 0.3	$ 367.3
PSCo	700.0	303.5	396.5	0.3	396.8
NSP-Minnesota	500.0	105.9	394.1	0.7	394.8
SPS	300.0	83.0	217.0	0.9	217.9
NSP-Wisconsin	150.0	11.0	139.0	0.9	139.9
Total	$ 2,450.0	$ 936.4	$ 1,513.6	$ 3.1	$ 1,516.7

[a] These credit facilities expire in July 2017.
[b] Includes outstanding commercial paper and letters of credit.

During the second quarter of 2014, Xcel Energy began working with its bank group to amend and extend the existing revolving credit agreements for Xcel Energy Inc. and each of its regulated subsidiaries. Xcel Energy expects to finalize these agreements during the third quarter of 2014.

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 July 29, 2014, 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.

Financing — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

During 2014, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In March, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044;
- In May, NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- In June, SPS issued $150 million of 3.30 percent first mortgage bonds due June 15, 2024; and
- In June, NSP-Wisconsin issued $100 million of 3.30 percent first mortgage bonds due June 15, 2024.

In connection with SPS' issuance of $150 million of 3.30 percent first mortgage bonds due June 15, 2024, SPS issued $250 million of collateral 8.75 percent first mortgage bonds due Dec. 1, 2018 to the trustee under its senior unsecured indenture in order to secure its previously issued Series G Senior Notes, 8.75 percent due Dec. 1, 2018, equally and ratably with SPS' first mortgage bonds as required by the terms of such Series G Senior Notes.

In March 2013, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $400 million of its common stock through an ATM program. During the six months ended June 30, 2014, Xcel Energy Inc. issued approximately 5.7 million shares of common stock through this program for approximately $175 million. As a result, Xcel Energy has completed its ATM program. Xcel Energy does not anticipate issuing any additional equity, beyond its dividend reinvestment program and to fund benefit programs, over the next five years 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 Minnesota Public Utilities Commission (MPUC). The rate case is 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 reflects an 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 includes a proposed rate moderation plan for 2014 and 2015. After reflecting interim rate adjustments, NSP-Minnesota requested a rate increase of $127 million or 4.6 percent in 2014 and an incremental rate increase of $164 million or 5.6 percent in 2015.

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the excess depreciation reserve and the use of expected funds from the U.S. Department of Energy (DOE) for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund NSP-Minnesota's decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello LCM/EPU project costs and NSP-Minnesota's request to amortize amounts associated with the canceled Prairie Island (PI) EPU project.

In December 2013, the MPUC approved interim rates of $127 million effective Jan. 3, 2014, subject to refund. The MPUC determined that the costs of Sherco Unit 3 would be allowed in interim rates, and that NSP-Minnesota's request to accelerate the depreciation reserve amortization was a permissible adjustment to its interim rate request.

In June 2014, intervening parties filed direct testimony proposing modifications to NSP-Minnesota's rate request. The Minnesota Department of Commerce (DOC) recommended an increase of approximately $61.6 million in 2014 and a step increase of $54.9 million for 2015, based on a recommended ROE of 9.8 percent and an equity ratio of 52.5 percent.

In July 2014, NSP-Minnesota filed rebuttal testimony and reduced its request to an increase in revenues of approximately $169.5 million or 6.2 percent in 2014 and an additional $95 million or 3.5 percent in 2015. The revision reflects an update to NSP-Minnesota's 2014 sales forecast and narrowed the number of disputed issues in the case by agreeing to or partially agreeing to an outcome on several smaller issues. NSP-Minnesota continues to support its initial filed position, including cost recovery of the Monticello LCM/EPU project, an ROE of 10.25 percent and property taxes. For the 2015 increase, NSP-Minnesota reduced its request by $3.5 million in order to focus the request on specific capital projects.

The following table summarizes the DOC's recommendations from NSP-Minnesota's filed request:

(Millions of Dollars)	DOC Direct Testimony 2014	NSP-Minnesota Rebuttal Testimony 2014
Filed rate request	$ 192.7	$ 192.7
Monticello EPU cost recovery	(31.3)	—
Sales forecast	(29.5)	(15.8)
ROE	(26.9)	—
Health care, pension and other benefits	(21.9)	(0.8)
Property taxes	(13.5)	—
PI EPU	(5.8)	(3.8)
Other, net	(2.2)	(2.8)
Total recommendation 2014	$ 61.6	$ 169.5

(Millions of Dollars)	DOC Direct Testimony 2015 Step	NSP-Minnesota Rebuttal Testimony 2015 Step
Filed rate request	$ 98.5	$ 98.5

Depreciation	(17.5)	—
Property taxes	(14.5)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)
DOE settlement proceeds	(10.8)	10.1
Capital changes and disallowances	(5.6)	—
Nuclear outage amortization	(5.5)	—
Emission chemicals	(3.0)	(0.2)
Excess depreciation reserve adjustment	22.7	—
Other, net	1.7	1.0
Total recommendation 2015 step increase	54.9	95.0
Cumulative total for 2014 and 2015 step increase	$ 116.5	$ 264.5

NSP-Minnesota's rebuttal rate request, moderation plan, interim rate adjustments and certain impacts on expenses are detailed in the table below:

(Millions of Dollars)	**2014**	**Percentage Increase**	**2015**	**Percentage Increase**
Rebuttal pre-moderation deficiency	$ 250		$ 68	
Moderation change compared to prior year:				
Depreciation reserve	(81)		53	
DOE settlement proceeds	—		(26)	
Rebuttal rate request	169	6.2 %	95	3.5 %
Interim rate adjustments	(66)		66	
PI EPU	4		(4)	
Revenue impact[(a)]	107		157	

Depreciation expense - decrease/(increase)	81	(46)
Recognition of DOE settlement proceeds	—	26
Rebuttal pre-tax impact on operating income	$ 188	$ 137

[(a)] NSP-Minnesota's total revenue for 2014 is capped at the interim rate level of $127 million and pre-tax operating income is capped at $208 million. This table demonstrates the impact of reducing NSP-Minnesota's rebuttal request.

NSP-Minnesota recorded a current regulatory liability representing the current best estimate of a refund obligation associated with interim rates of approximately $12.5 million as of June 30, 2014.

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

- Surrebuttal Testimony — Aug. 4, 2014;
- Evidentiary Hearing — Aug. 11-18, 2014;
- Initial Brief — Sept. 23, 2014;
- Reply Brief — Oct. 14, 2014; and
- Administrative Law Judge (ALJ) Report — Dec. 22, 2014.

A final MPUC decision is anticipated in March 2015.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent. Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes AFUDC. Project expenditures were initially estimated at approximately $320 million, excluding AFUDC, in 2008 in NSP-Minnesota's EPU certificate of need and plant life extension filings.

In October 2013, NSP-Minnesota filed a report to further support the change and prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and (3) additional Nuclear Regulatory Commission (NRC) licensing related requests over the five-plus year application process. NSP-Minnesota has provided information that the cost deviation is in line with similar upgrade projects undertaken by other utilities and the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and has begun the process to comply with the license requirements for higher power levels, subject to NRC oversight and review.

On July 2, 2014, the DOC filed testimony and recommended a disallowance of recovery of approximately $71.5 million of project costs, including expenditures and associated AFUDC, on a Minnesota jurisdictional basis. This equates to a total NSP System amount of approximately $94 million.

The DOC's recommendation indicated that although the combined LCM/EPU project is cost effective, NSP-Minnesota should have done a better job of estimating initial project costs of the investments required to achieve 71 megawatts (MW) of additional capacity (i.e., EPU costs) as opposed to investments required to extend the life of the plant. They asserted that approximately 85 percent of the total $665 million in costs were associated with project components required solely to achieve the EPU.

The DOC's recommendation, NSP-Minnesota's response and comments of other parties are expected to be considered by an ALJ later this year, who in turn will make a report of recommendations to the MPUC. The results and any recommendations from the conclusion of this prudence proceeding are expected to be considered by the MPUC in NSP-Minnesota's pending Minnesota 2014 Multi-Year electric rate case.

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

- Rebuttal Testimony — Aug. 26, 2014;
- Surrebuttal Testimony — Sept. 19, 2014;
- Hearing — Sept. 25 - Sept. 30, 2014;
- Reply Brief — Nov. 21, 2014; and
- ALJ Report — Dec. 31, 2014.

A final MPUC decision is anticipated in the first quarter of 2015.

NSP System Resource Plans — In March 2013, the MPUC approved NSP-Minnesota's Resource Plan and ordered a competitive acquisition process with the goal of adding approximately 500 MW of generation to the NSP System by 2019.

In May 2014, the MPUC issued its order directing NSP-Minnesota to negotiate a 100 MW solar purchased power agreement (PPA) with Geronimo Energy, a natural gas, combined-cycle PPA with Calpine, a natural gas, combustion turbine PPA with Invenergy and to file these agreements later this fall. The MPUC also directed NSP-Minnesota to present its final pricing terms for its 215 MW natural gas combustion turbine, self-build option at the Black Dog site. The MPUC is expected to rule on the four options later this year.

In early 2013, NSP-Minnesota also issued a request for proposal (RFP) for wind generation and subsequently sought commission approval of the following four wind projects:

- A 200 MW ownership project for the Pleasant Valley wind farm in Minnesota;
- A 150 MW ownership project for the Border Winds wind farm in North Dakota;
- A 200 MW PPA with Geronimo Energy, LLC for the Odell wind farm in Minnesota; and
- A 200 MW PPA with Geronimo Energy, LLC for the Courtenay wind farm in North Dakota.

In October 2013, the MPUC approved the four wind projects. In 2014, the North Dakota Public Service Commission approved the prudence of the Border Winds project as part of the rate case settlement and determined it will address the Pleasant Valley project at a later date. In June and July of 2014, NSP-Minnesota finalized agreements with Renewable Energy Systems Americas, Inc. for the Pleasant Valley and Border Winds projects and anticipates both projects going into service in 2015.

In April 2014, NSP-Minnesota issued a RFP for up to 100 MWs of solar generation resources. Proposals were received in June 2014. NSP-Minnesota is evaluating such bids and plans to submit recommendations regarding selected bids with the MPUC in October 2014.

NSP-Minnesota - Gas Utility Infrastructure Cost (GUIC) Rider — In the third quarter of 2014, NSP-Minnesota plans to file a GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessment and system upgrades in 2015 and beyond, as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota is requesting recovery of approximately $14.9 million from Minnesota gas utility customers beginning Jan.1, 2015, including $4.8 million of deferred sewer separation and integrity management costs. An MPUC decision is anticipated by the end of 2014.

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 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 Transmission Cost Recovery (TCR) rider and Infrastructure rider projects to base rates.

The major components of the request are as follows:

(Millions of Dollars)	Request
Nuclear investments and operating costs	$ 13.4
Other production, transmission and distribution	5.0
Technology improvements	2.1
Pension and O&M	1.6
Wind generation facilities	1.4
Capital structure	1.1
Incremental increase to base rates	$ 24.6
Infrastructure rider to be included in base rates	$ (8.4)
TCR rider to be included in base rates	(0.6)
Net request	$ 15.6

A procedural schedule is anticipated to be established in the second half of 2014. Final rates are expected to be effective in the first quarter of 2015.

***NSP-Wisconsin 2015 Electric Rate Case* —** In May 2014, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to increase electric rates by $20.6 million, or 3.2 percent, effective Jan. 1, 2015. The request is for the limited purpose of updating 2015 electric rates to reflect anticipated increases in the production and transmission fixed charges and the fuel and purchased power components of the interchange agreement with NSP-Minnesota. No changes are being requested to the capital structure or the 10.2 percent ROE authorized by the PSCW in the 2014 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 for 2015 only, in which 100 percent of the earnings above the authorized ROE would be refunded to customers.

The major cost components of the requested increase are summarized below:

(Millions of Dollars)	Request
Production and transmission fixed charges	$ 28.1
Fuel and purchased power	13.9
Sub-Total	$ 42.0
NSP-Minnesota transmission depreciation reserve	$ (16.2)
Monticello EPU deferral	(5.2)
Total	$ 20.6

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

- Direct Testimony (PSCW staff and intervenors) — Oct. 3, 2014;
- Rebuttal Testimony — Oct. 17, 2014;
- Surrebuttal Testimony — Oct. 24, 2014; and
- Evidentiary Hearing — Oct. 28, 2014.

A final PSCW decision is anticipated by the end of the year with final rates implemented in January 2015.

PSCo – Colorado 2014 Electric Rate Case — In June 2014, PSCo filed an electric rate case in Colorado with the Colorado Public Utilities Commission (CPUC) requesting an increase in annual revenue of approximately $137.7 million, or 4.89 percent. The request includes the initiation of a CACJA rider as part of the overall 2015 rate case request of approximately $95 million, as well as additional amounts for calendar years 2016 and 2017. The CACJA rider is anticipated to increase revenue recovery by approximately $40 million in 2016 and then decline to approximately $36 million in 2017. PSCo's objective is to establish a multi-year regulatory plan that provides certainty for PSCo and its customers.

The rate filing is based on a 2015 test year, a requested ROE of 10.35 percent, an electric rate base of $6.39 billion and an equity ratio of 56 percent. As part of the filing, PSCo will transfer approximately $19.9 million from the transmission rider to base rates. This transfer will not impact customer bills. The CACJA rider is projected to recover incremental investment and expenses, based on a comprehensive plan to retire certain coal plants, add pollution control equipment to other existing coal units and add natural gas generation. The CACJA project investment is expected to be completed by 2017.

In July 2014, the CPUC set hearings for early December 2014. A decision as well as implementation of final rates are anticipated in the first quarter of 2015.

***Boulder, Colo. Municipalization* —** PSCo's franchise agreement with the City of Boulder (Boulder) expired on Dec. 31, 2010. In November 2011, a ballot measure was passed by the citizens of Boulder, which authorized the formation and operation of a municipal light and power utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage.

In May 2014, the Boulder City Council passed an ordinance to establish an electric utility. In June 2014, PSCo filed a complaint in the Boulder District Court seeking a declaratory ruling that this ordinance violates Boulder's charter requirements. Subsequently, Boulder filed a motion to dismiss PSCo's complaint, which is still pending.

Boulder sent PSCo its final offer of $128 million for certain portions of PSCo's transmission and distribution business, which includes Boulder and certain areas outside city limits. PSCo has notified Boulder that its offer has deficiencies related to property descriptions as well as other relevant information impacting the remainder of PSCo's system. Under Colorado law, a condemning entity must pay the owner fair market value for the taking of and damages to the remainder of the property. In July 2014, Boulder filed a petition for condemnation in the Boulder District Court.

The CPUC has previously ruled that it has jurisdiction under Colorado law to determine the utility that will serve customers outside Boulder's city limits, and will determine certain system separation matters as well as what facilities need to be constructed to ensure reliable service. The CPUC has declared that it should make its determinations prior to any eminent domain actions. In January 2014, Boulder appealed this ruling to the Boulder District Court. PSCo and the CPUC filed briefs in June 2014 in opposition of Boulder's appeal. This matter is currently pending.

If Boulder were to succeed in the eminent domain proceeding, PSCo would seek to obtain full compensation for the business and its associated property taken by Boulder, as well as for all damages resulting to PSCo and its system. PSCo would also seek appropriate compensation for stranded costs with the Federal Energy Regulatory Commission.

SPS – Texas 2014 Electric Rate Case — In January 2014, SPS filed a retail electric rate case in Texas with each of its Texas municipalities and the Public Utility Commission of Texas (PUCT) for a net increase in annual revenue of approximately $52.7 million, or 5.8 percent. The net increase reflected a base rate increase, revenue credits transferred from base rates to rate riders or the fuel clause, and resetting the Transmission Cost Recovery Factor (TCRF) to zero when the final base rates become effective. In April 2014, SPS revised its request to a net increase of $48.1 million, based on updated information.

The rate filing is based on a historic test year ending June 2013, a requested ROE of 10.40 percent, an electric rate base of approximately $1.27 billion and an equity ratio of 53.89 percent. The requested rate increase reflected an increase in depreciation expense of approximately $16 million.

SPS, intervenors, and other parties have commenced settlement negotiations. A final settlement is anticipated to be filed with the PUCT in the third quarter of 2014. A final decision is anticipated later this year and final rates are expected to be effective retroactive to June 1, 2014.

SPS – New Mexico 2014 Electric Rate Case — In December 2012, SPS filed an electric rate case in New Mexico with the New Mexico Public Regulation Commission (NMPRC) for an increase in annual revenue of approximately $45.9 million effective in 2014. The rate filing was based on a 2014 forecast test year, a requested ROE of 10.65 percent, an electric rate base of $479.8 million and an equity ratio of 53.89 percent.

In September 2013, SPS filed rebuttal testimony, revising its requested rate increase to $32.5 million, based on updated information and an ROE of 10.25 percent. The request reflected a base and fuel increase of $20.9 million, an increase of rider revenue of $12.1 million and a decrease to other of $0.5 million.

In March 2014, the NMPRC approved an overall increase of approximately $33.1 million. The increase reflects a base rate increase of $12.7 million and rider recovery of $18.1 million for renewable energy costs, both based on an ROE of 9.96 percent and an equity ratio of 53.89 percent. Final rates were effective April 5, 2014. In April 2014, the New Mexico Attorney General (NMAG) filed a request for rehearing. The rehearing request was denied by the NMPRC. In June 2014, the NMAG filed an appeal of the NMPRC's denial to the New Mexico Supreme Court. A decision is expected in 2015.

The following table summarizes the NMPRC's approval from SPS' revised request:

(Millions of Dollars)	NMPRC Approval
SPS revised request, September 2013	$ 32.5
Fuel clause adjustment credit — non-renewable energy costs	2.3
SPS revised request, fuel adjusted	34.8
ROE (9.96 percent)	(1.2)
Rate rider adjustment — renewable energy costs	6.0
Base rate reduction for rate rider — renewable energy costs	(6.0)
Other, net	(0.5)
Approved increase, March 2014	$ 33.1

Means of recovery:

Base revenue	$	12.7
Rider revenue		18.1
Fuel clause		2.3
	$	33.1

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

Xcel Energy Earnings Guidance — Xcel Energy's 2014 ongoing earnings guidance is $1.90 to $2.05 per share. Key assumptions related to 2014 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 approximately 2.0 percent.
- Capital rider revenue is projected to increase by $40 million to $50 million over 2013 levels.
- O&M expenses are projected to increase approximately 2 percent to 3 percent over 2013 levels.
- Depreciation expense is projected to increase $30 million to $40 million over 2013 levels, reflecting the proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota's moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $81 million in 2014.
- Property taxes are projected to increase approximately $40 million to $50 million over 2013 levels.

- Interest expense (net of AFUDC — debt) is projected to decrease $5 to $15 million from 2013 levels.
- AFUDC — equity is projected to increase approximately $5 million to $10 million over 2013 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 504 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 a normalized 2013 EPS of $1.90 per share, which represented the mid-point of our 2013 earnings guidance range;
- Deliver annual dividend increases of 4 percent to 6 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.

XCEL ENERGY INC. AND SUBSIDIARIES

EARNINGS RELEASE SUMMARY (Unaudited)

(amounts in thousands, except per share data)

	Three Months Ended June 30	
	2014	**2013**
Operating revenues:		
Electric and natural gas	$ 2,666,765	$ 2,561,198

Other	18,331	17,715
Total operating revenues	2,685,096	2,578,913
Net income	$ 195,164	$ 196,857
Weighted average diluted common shares outstanding	503,456	498,036
Components of EPS — Diluted		
Regulated utility	$ 0.42	$ 0.44
Xcel Energy Inc. and other costs	(0.03)	(0.04)
GAAP diluted EPS	**$ 0.39**	**$ 0.40**

	Six Months Ended June 30	
	2014	**2013**
Operating revenues:		
Electric and natural gas	$ 5,848,163	$ 5,322,990
Other	39,537	38,772
Total operating revenues	5,887,700	5,361,762
Net income	$ 456,385	$ 433,427
Weighted average diluted common shares outstanding	501,612	494,303
Components of EPS — Diluted		
Regulated utility	$ 0.96	$ 0.96
Xcel Energy Inc. and other costs	(0.05)	(0.08)
GAAP diluted EPS	**$ 0.91**	**$ 0.88**
Book value per share	$ 19.64	$ 18.70

Contacts

Xcel Energy Inc.
Paul Johnson, 612-215-4535
Vice President, Investor Relations
or
News media inquiries only:
Xcel Energy Media Relations, 612-215-5300
Xcel Energy internet address: www.xcelenergy.com