414 Nicollet Mall
Minneapolis, MN 55401

Jan. 29, 2015

XCEL ENERGY
2014 YEAR END EARNINGS REPORT

- Ongoing 2014 earnings per share were $2.03 compared with $1.95 per share in 2013;
- GAAP (generally accepted accounting principles) 2014 earnings per share were $2.03 compared with $1.91 per share in 2013; and
- Xcel Energy reaffirms 2015 ongoing earnings guidance of $2.00 to $2.15 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2014 GAAP earnings of $1,021 million, or $2.03 per share, compared with 2013 GAAP earnings of $948 million, or $1.91 per share.

Ongoing earnings, which exclude adjustments for certain items, were $2.03 per share for 2014 compared with $1.95 per share in 2013. Ongoing earnings increased as a result of higher electric and natural gas margins due to rate increases in various jurisdictions, weather-normalized sales growth and lower interest charges. These positive factors were partially offset by the unfavorable impact of milder weather, as well as higher expected operating and maintenance expenses, property taxes and depreciation.

2013 GAAP earnings include a $0.04 per share charge for a potential SPS customer refund based on FERC orders issued in August 2013. This item was excluded from 2013 ongoing earnings.

"It was a good finish to the year and we performed consistent with our plans," stated Ben Fowke, Chairman, President and Chief Executive Officer. "Our 2014 ongoing earnings per share were in the upper half of our guidance range, we experienced better than expected sales growth and we held operating and maintenance expenses to a moderate increase. While we faced headwinds earlier in the year, I am pleased to announce that we delivered solid results."

Fowke cited progress in major regulatory proceedings and progress in completing major construction projects as contributing to the 2014 results. "We completed rate cases in New Mexico, Texas and Wisconsin and received a constructive administrative law judge recommendation in our Minnesota electric multi-year case," Fowke continued. "And this month, we reached a settlement establishing a new three-year electric rate plan in Colorado, building off our current multi-year plan and providing greater rate certainty for the future. At the same time, we continue to make significant progress on investments in transmission and clean generation projects that will serve our customers well into the future."

"These investments provide a platform for future growth for Xcel Energy," Fowke said. "In addition to achieving great 2014 results, we took important actions to position us to achieve our long-term strategic objectives. Continued growth through smart investments in strategic infrastructure and developing new service options for customers will position us to be successful as the energy industry evolves to be more competitive. Forming the TransCos and our recently filed Minnesota resource plan are good examples of these efforts."

Going forward, the company is focused on improving the performance of its operating companies. "New long-term regulatory compacts are essential to our future success and will be central in closing the gap between allowed and earned returns," Fowke said. "Recently, we made a filing in Minnesota that proposes to streamline the regulatory process, provide a longer-term compact and achieve important energy policy objectives. We look forward to working with stakeholders to get this important work done."

"I am pleased with the momentum we have created and look forward to carrying it into 2015," Fowke concluded. "Xcel Energy reaffirms our 2015 ongoing earnings guidance of $2.00 to $2.15 per share."

Earnings Adjusted for Certain Items (Ongoing Earnings)

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

Diluted Earnings (Loss) Per Share [(a)]	Three Months Ended Dec. 31 2014	Three Months Ended Dec. 31 2013	Twelve Months Ended Dec. 31 2014	Twelve Months Ended Dec. 31 2013
Ongoing diluted EPS	**$ 0.39**	**$ 0.30**	**$ 2.03**	**$ 1.95**
SPS FERC complaint case orders [(b)]	—	—	—	(0.04)
GAAP diluted EPS	**$ 0.39**	**$ 0.30**	**$ 2.03**	**$ 1.91**

(a) See Note 2.
(b) See Note 7.

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

US Dial-In:	(888) 713-4508
International Dial-In:	(913) 312-6688
Conference ID:	3939789

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. CST on Jan. 29 through 10:59 p.m. CST on Jan. 30.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	3939789

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 EPS 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 slowdown 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; 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, 2013; 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 Reports on Form 10-Q for the quarters ended March 31, June 30 and Sept. 30, 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	

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

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
	2014	2013	2014	2013
Operating revenues				
Electric	$ 2,250,191	$ 2,122,047	$ 9,465,890	$ 9,034,045
Natural gas	657,274	588,404	2,142,738	1,804,679
Other	21,163	20,371	77,507	76,198
Total operating revenues	2,928,628	2,730,822	11,686,135	10,914,922
Operating expenses				
Electric fuel and purchased power	1,021,644	984,641	4,210,142	4,018,672
Cost of natural gas sold and transported	438,406	379,764	1,372,479	1,082,751
Cost of sales — other	9,569	9,491	34,352	33,323
Operating and maintenance expenses	620,241	606,439	2,334,379	2,273,532
Conservation and demand side management program expenses	78,220	68,438	301,772	260,726
Depreciation and amortization	262,400	256,732	1,019,045	977,863
Taxes (other than income taxes)	106,898	99,735	465,836	420,500
Total operating expenses	2,537,378	2,405,240	9,738,005	9,067,367
Operating income	391,250	325,582	1,948,130	1,847,555
Other income (expense), net	609	(959)	5,296	2,972
Equity earnings of unconsolidated subsidiaries	7,501	7,641	30,151	30,020
Allowance for funds used during construction — equity	20,898	24,536	89,750	87,683
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,842, $6,077, $22,986, and $30,135, respectively	144,895	144,173	566,608	575,199
Allowance for funds used during construction — debt	(8,793)	(10,728)	(38,402)	(39,179)
Total interest charges and financing costs	136,102	133,445	528,206	536,020
Income before income taxes	284,156	223,355	1,545,121	1,432,210
Income taxes	87,817	73,300	523,815	483,976
Net income	$ 196,339	$ 150,055	$ 1,021,306	$ 948,234
Weighted average common shares outstanding:				
Basic	506,411	498,499	503,847	496,073
Diluted	506,799	498,802	504,117	496,532
Earnings per average common share:				
Basic	$ 0.39	$ 0.30	$ 2.03	$ 1.91
Diluted	0.39	0.30	2.03	1.91
Cash dividends declared per common share	$ 0.30	$ 0.28	$ 1.20	$ 1.11

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

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

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

Note 1. Earnings Per Share Summary

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings (Loss) Per Share	**2014**	**2013**	**2014**	**2013**
Public Service Company of Colorado (PSCo)	$ 0.18	$ 0.15	$ 0.90	$ 0.91
NSP-Minnesota	0.17	0.12	0.80	0.79
Southwestern Public Service Company (SPS)	0.03	0.04	0.26	0.23
NSP-Wisconsin	0.03	0.01	0.14	0.12
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.04	0.04
Regulated utility	0.42	0.33	2.14	2.09
Xcel Energy Inc. and other	(0.03)	(0.03)	(0.11)	(0.14)
Ongoing [(a)] diluted EPS	0.39	0.30	2.03	1.95
SPS FERC complaint case orders [(b)]	—	—	—	(0.04)
GAAP diluted EPS	**$ 0.39**	**$ 0.30**	**$ 2.03**	**$ 1.91**

(a) See Note 2.
(b) See Note 7.

PSCo — PSCo's ongoing earnings decreased $0.01 per share for 2014. Higher natural gas and electric margins primarily due to rate increases, higher allowance for funds used during construction (AFUDC), lower operating and maintenance (O&M) expenses and weather-normalized sales growth were offset by higher property taxes, depreciation, accruals associated with the electric earnings test refund obligations and the unfavorable impact of weather.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.01 per share for 2014. Ongoing earnings were positively impacted by electric rate increases in Minnesota (interim, subject to refund) and North Dakota and weather-normalized sales growth. These items were partially offset by higher O&M expenses, the unfavorable impact of weather, lower AFUDC and increased property taxes and interest charges.

SPS — SPS' ongoing earnings increased $0.03 per share for 2014. Electric rate increases in Texas and New Mexico and weather-normalized sales growth offset higher O&M and depreciation expenses.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.02 per share for 2014. An electric rate increase led to higher electric margin, while weather-normalized sales growth positively impacted both electric and natural gas margins. These increases were partially offset by additional O&M expenses.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Earnings improved by $0.03 per share for 2014, largely due to lower financing costs as a result of the refinancing of junior subordinated notes.

The following table summarizes significant components contributing to the changes in 2014 EPS compared with the same period in 2013:

Diluted Earnings (Loss) Per Share [(a)]	**Three Months Ended Dec. 31**	**Twelve Months Ended Dec. 31**
2013 GAAP diluted EPS	**$ 0.30**	**$ 1.91**
SPS FERC complaint case orders [(b)]	—	0.04
2013 ongoing diluted EPS	**0.30**	**1.95**
Components of change — 2014 vs. 2013		
Higher electric margins (excludes 2013 impact of SPS FERC complaint case orders)	0.11	0.26
Higher natural gas margins	0.01	0.06
Lower interest charges (excludes 2013 impact of SPS FERC complaint case orders)	—	0.01
Lower AFUDC — equity	(0.01)	—
Higher O&M expenses	(0.02)	(0.07)
Higher taxes (other than income taxes)	(0.01)	(0.06)
Higher depreciation and amortization	(0.01)	(0.05)
Higher conservation and demand side management (DSM) program expenses	(0.01)	(0.05)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.01)	(0.03)
Other, net	0.04	0.01
2014 ongoing and GAAP diluted EPS	**$ 0.39**	**$ 2.03**

The following table summarizes the ROE for Xcel Energy and its utility subsidiaries:

ROE — 2014	**PSCo**	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
2014 ongoing and GAAP ROE	9.40%	8.82%	8.88%	10.85%	10.33%

ROE — 2013	**PSCo**	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
2013 ongoing ROE	9.66%	9.24%	9.03%	10.61%	10.50%
SPS FERC complaint case orders [(b)]	—	—	(1.54)	—	(0.22)
2013 GAAP ROE	9.66%	9.24%	7.49%	10.61%	10.28%

(a) See Note 2.
(b) See Note 7.

Note 2. Regulated Utility Results

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

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one 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.

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

	Three Months Ended Dec. 31			Twelve Months Ended Dec. 31		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
HDD	1.8%	8.3%	(6.6)%	7.8%	6.5%	0.4%
CDD [(a)]	N/A	N/A	N/A	(2.6)	24.7	(20.3)
THI [(a)]	N/A	N/A	N/A	(11.9)	21.8	(24.2)

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

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

	Three Months Ended Dec. 31			Twelve Months Ended Dec. 31		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
Retail electric	$ —	$ 0.009	$ (0.009)	$ 0.010	$ 0.088	$ (0.078)
Firm natural gas	0.001	0.007	(0.006)	0.019	0.021	(0.002)
Total	$ 0.001	$ 0.016	$ (0.015)	$ 0.029	$ 0.109	$ (0.080)

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

	Three Months Ended Dec. 31				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	(1.9)%	(1.2)%	(1.5)%	(1.9)%	(2.1)%
Electric commercial and industrial	1.4	3.7	2.7	1.4	0.3
Total retail electric sales	0.5	2.2	1.9	0.3	(0.5)
Firm natural gas sales	(0.9)	(2.2)	N/A	—	(2.4)

	Three Months Ended Dec. 31				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	(0.1)%	1.2%	1.3%	(0.6)%	(0.3)%
Electric commercial and industrial	1.5	3.9	2.6	1.4	0.4
Total retail electric sales	1.0	3.1	2.3	0.8	0.2
Firm natural gas sales	4.1	4.2	N/A	4.4	3.5

	Twelve Months Ended Dec. 31				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	(1.8)%	(0.3)%	(0.4)%	(2.8)%	(1.6)%
Electric commercial and industrial	1.0	4.2	2.5	0.3	—
Total retail electric sales	0.2	2.8	1.8	(0.7)	(0.5)
Firm natural gas sales	2.3	7.4	N/A	(0.7)	7.3

	Twelve Months Ended Dec. 31				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	0.5%	0.5%	0.4%	0.3%	0.7%
Electric commercial and industrial	1.7	4.4	2.8	1.6	0.6
Total retail electric sales	1.3	3.3	2.3	1.2	0.6
Firm natural gas sales	4.6	3.8	N/A	5.2	3.6

Weather-normalized Electric Growth

- NSP-Wisconsin's electric sales growth was largely due to strong sales to large commercial and industrial (C&I) customers primarily in the oil, gas and sand mining industries.
- SPS' C&I growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area.
- PSCo's electric sales growth was primarily due to customers in the food manufacturing, fracking and mining industries.
- NSP-Minnesota's electric sales growth was led by an increased number of customers for both residential and small C&I, as well as higher use per customer in small C&I.

Weather-normalized Natural Gas Growth

- Across our natural gas service territories, strong sales were experienced in 2014, which continued the trend that began in the last half of 2013.

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 Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	2014	2013	2014	2013
Electric revenues	$ 2,250	$ 2,122	$ 9,466	$ 9,034
Electric fuel and purchased power	(1,022)	(985)	(4,210)	(4,019)
Electric margin	$ 1,228	$ 1,137	$ 5,256	$ 5,015

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

(Millions of Dollars)	Three Months Ended Dec. 31 2014 vs. 2013	Twelve Months Ended Dec. 31 2014 vs. 2013
Retail rate increases [(a)]	$ 36	$ 129
Non-fuel riders	19	57
Conservation and DSM program revenues (offset by expenses)	11	44
Transmission revenue, net of costs	6	31
Retail sales growth, excluding weather impact	2	24
NSP-Wisconsin fuel recovery	8	11
Estimated impact of weather	(7)	(60)
Firm wholesale	1	(6)
Other, net	15	(15)
Total increase in ongoing electric margin	91	215
SPS FERC complaint case orders [(b)]	—	26
Total increase in GAAP electric margin	$ 91	$ 241

(a) The retail rate increases include final rates in Texas, Colorado (net of estimated earnings test refund obligations), New Mexico, Wisconsin and North Dakota and interim rates in Minnesota, subject to and net of estimated provision for refund. See Note 4 for further discussion.

(b) As a result of two orders issued by the Federal Energy Regulatory Commission (FERC) in August 2013, a pretax charge of approximately $36 million ($32 million in electric revenues, of which $6 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in 2013. See Note 5.

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 Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	**2014**	**2013**	**2014**	**2013**
Natural gas revenues	$ 657	$ 588	$ 2,143	$ 1,805
Cost of natural gas sold and transported	(438)	(380)	(1,372)	(1,083)
Natural gas margin	$ 219	$ 208	$ 771	$ 722

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

(Millions of Dollars)	**Three Months Ended Dec. 31 2014 vs. 2013**	**Twelve Months Ended Dec. 31 2014 vs. 2013**
Retail rate increases (Colorado)	$ 3	$ 19
Pipeline system integrity adjustment rider (Colorado), partially offset in O&M expenses	3	14
Retail sales growth, excluding weather impact	3	10
Estimated impact of weather	(5)	(1)
Other, net	7	7
Total increase in natural gas margin	$ 11	$ 49

O&M Expenses — O&M expenses increased $13.8 million, or 2.3 percent, for the fourth quarter of 2014 and $60.8 million, or 2.7 percent, for 2014 compared with the same periods in 2013. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	**Three Months Ended Dec. 31 2014 vs. 2013**	**Twelve Months Ended Dec. 31 2014 vs. 2013**
Nuclear plant operations and amortization	$ 11	$ 36
2013 gain on sale of transmission assets	14	14
Transmission costs	(2)	4
Electric and natural gas distribution expenses	(9)	1
Employee benefits	12	(6)
Plant generation costs	(11)	(3)
Other, net	(1)	15
Total increase in O&M expenses	$ 14	$ 61

- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants; and
- Gain on sale of transmission assets relates to the 2013 gain associated with the sale of certain SPS' transmission assets to Sharyland Distribution and Transmission Services, LLC.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $9.8 million, or 14.3 percent, for the fourth quarter of 2014 and $41.0 million, or 15.7 percent, for 2014 compared with the same periods in 2013. These increases were primarily attributable to higher electric recovery rates at NSP-Minnesota. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization increased $5.7 million, or 2.2 percent, for the fourth quarter of 2014 and $41.2 million, or 4.2 percent, for 2014 compared with the same periods in 2013. The increases were primarily attributable to the Prairie Island (PI) steam generator replacement placed in service in December 2013 and 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 $7.2 million, or 7.2 percent, for the fourth quarter of 2014 and $45.3 million, or 10.8 percent, for 2014 compared with the same periods in 2013. The increases were primarily due to higher property taxes in Colorado, Minnesota and Texas.

AFUDC, Equity and Debt — AFUDC decreased $5.6 million for the fourth quarter of 2014 and increased $1.3 million for 2014 compared with the same periods in 2013. The year-to-date increase was primarily due to construction related to the Clean Air Clean Jobs Act (CACJA) and the expansion of transmission facilities, partially offset by the portion of the Monticello life cycle management (LCM)/extended power uprate (EPU) placed in service in July 2013 and the PI steam generator replacement placed in service in December 2013.

Interest Charges — Interest charges increased $0.7 million, or 0.5 percent, for the fourth quarter of 2014 and decreased $8.6 million, or 1.5 percent, for 2014 compared with the same periods in 2013. The annual decrease was primarily due to refinancings at lower interest rates, partially offset by higher long-term debt levels. In addition, interest charges in 2013 reflected $4 million of interest associated with the customer refund at SPS based on a FERC order, interest on customer refunds in Minnesota and the write off of $6.3 million of unamortized debt expense related to the junior subordinated notes called in May 2013.

***Income Taxes* —** Income tax expense increased $14.5 million for the fourth quarter of 2014 compared with the same period in 2013. The increase was primarily due to higher 2014 pretax earnings and additional expense related to unrecognized tax benefits. These were partially offset by increases in tax benefits associated with a carryback and research and experimentation credits resulting from federal legislation in the fourth quarter of 2014. The effective tax rate (ETR) was 30.9 percent for the fourth quarter of 2014 compared with 32.8 percent for the same period in 2013, largely due to these adjustments.

Income tax expense increased $39.8 million for 2014 compared with 2013. The increase was primarily due to higher 2014 pretax earnings and recognition of additional research and experimentation credits in 2013. These were partially offset by a 2014 tax benefit for prior year adjustments. The ETR was 33.9 percent for 2014 compared with 33.8 percent for 2013.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	Dec. 31, 2014	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.3	1%
Short-term debt	1.0	4
Long-term debt	11.5	50
Total debt	12.8	55
Common equity	10.2	45
Total capitalization	$ 23.0	100%

Credit Facilities — As of Jan. 27, 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	$ 439.5	$ 560.5	$ 0.4	$ 560.9
PSCo	700.0	445.2	254.8	0.4	255.2
NSP-Minnesota	500.0	276.0	224.0	0.6	224.6
SPS	400.0	136.0	264.0	0.2	264.2
NSP-Wisconsin	150.0	95.0	55.0	0.9	55.9
Total	$ 2,750.0	$ 1,391.7	$ 1,358.3	$ 2.5	$ 1,360.8

(a) These credit facilities have been amended to extend the maturity to 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 Jan. 27, 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.

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 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.

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

2014 Financing Activity — 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.

Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an at-the-market (ATM) program for approximately $175 million during the first six months of 2014. As a result, Xcel Energy completed its ATM program as of June 30, 2014. Xcel Energy does not anticipate issuing any additional equity, beyond its dividend reinvestment program and benefit programs, over the next five years based on its current capital expenditure plan.

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 Utility Commission (MPUC). The rate case is based on a requested 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 includes a proposed rate moderation plan for 2014 and 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 United States 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 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 August 2014, NSP-Minnesota revised its requested rate increase to $142.2 million for 2014 and to $106.0 million for 2015, for a total combined unadjusted increase of $248.2 million.

On Dec. 26, 2014, the Administrative Law Judge (ALJ) issued her recommendations in the NSP-Minnesota electric rate case. While the report did not quantify the overall rate increases, NSP-Minnesota estimates that her recommendations would result 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.

The following table summarizes the estimated impact of the ALJ's recommendation, Minnesota Department of Commerce (DOC)'s previously filed surrebuttal testimony and NSP-Minnesota's revised request and includes certain estimated adjustments:

2014 Rate Request (Millions of Dollars)	ALJ	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$ 192.7	$ 192.7	$ 192.7
Sales forecast (true-up to 12 months of actual weather-normalized sales)	(15.8)	(43.2)	(15.8)
ROE	(28.4)	(36.2)	—
Monticello EPU cost recovery	(31.3)	(33.9)	—
Monticello EPU depreciation deferral	—	—	(12.2)
Property taxes	(9.0)	(9.0)	(9.0)
PI EPU	(5.1)	(5.1)	(5.1)
Health care, pension and other benefits	(1.9)	(11.4)	(1.9)
Other, net	(5.2)	(8.0)	(6.5)
Total recommendation 2014 — unadjusted	$ 96.0	$ 45.9	$ 142.2
Estimated true-up adjustments:			
Sales forecast [(a)]	$ (22.7)	$ 4.7	$ (22.7)
Property taxes [(b)]	(4.2)	(4.2)	(4.2)
Total recommendation 2014 — adjusted	$ 69.1	$ 46.4	$ 115.3

2015 Rate Request (Millions of Dollars)	ALJ	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$ 98.5	$ 98.5	$ 98.5
Monticello EPU cost recovery	29.1	29.1	—
Monticello EPU cost disallowance [(c)]	—	(10.2)	—
Excess depreciation reserve adjustment [(d)]	—	(22.7)	—
Depreciation	—	(17.5)	—
Monticello EPU depreciation deferral	—	—	1.6
Monticello EPU step increase	—	—	10.1
Property taxes	(3.3)	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)	(11.1)
DOE settlement proceeds	10.1	10.1	10.1
Emission chemicals	(1.6)	(1.6)	(1.6)
Other, net	0.7	(4.8)	1.7
Total recommendation 2015 step increase	$ 122.4	$ 66.5	$ 106.0
Unadjusted cumulative total for 2014 and 2015 step increase	$ 218.4	$ 112.4	$ 248.2
Estimated adjusted cumulative total for 2014 and 2015 step increase	$ 191.5	$ 112.9	$ 221.3

(a) The true-up adjustment for the sales forecast reflects weather-normalized sales through December 2014.

(b) The true-up adjustment for property taxes reflects NSP-Minnesota's 2014 year end property tax accruals.

(c) In July 2014, the DOC recommended a cost disallowance of approximately $71.5 million on a Minnesota jurisdictional basis which equates to a total NSP System, which includes NSP-Minnesota and NSP-Wisconsin, disallowance of approximately $94 million. This would reduce NSP-Minnesota's revenue requirement by approximately $10.2 million in 2015.

(d) Adjustment is due to timing differences and/or methodology of accelerating amortization of the excess depreciation reserve over three years.

The ALJ recommended no recovery of the Monticello EPU project costs in 2014, accepting the DOC's argument that the EPU portion was not used and useful in 2014 and should be treated as a 2015 step project. NSP-Minnesota fully met the Nuclear Regulatory Commission (NRC)'s requirements for the EPU as of Dec. 31, 2014. NSP-Minnesota is currently executing the power ascension plan consistent with the NRC license amendment approval and as of Dec. 31, 2014 had operated the plant using 56 megawatts (MW) of the additional 71 MW from the EPU. The full 71 MW of additional EPU output is expected to be attained in the first half of 2015. Although the final NRC requirements have been met, rate recovery is still subject to true-up. The ALJ recommendation does not reflect any potential adjustments for the pending Monticello prudence review.

The ALJ did not make a recommendation on the use of the surplus depreciation reserve in NSP-Minnesota's rate moderation proposal. The table above reflects NSP-Minnesota's filed position for the use of the proposed amortization of the surplus depreciation reserve.

The ALJ also recommended adoption of a full decoupling pilot for the residential and small C&I classes, based on actual sales, effective the month after the MPUC issues its final order in 2015. Full decoupling would eliminate the impact of weather variability on electric sales for the residential and small C&I classes for NSP-Minnesota.

The amounts outlined above do not reflect recently passed legislation extending bonus depreciation. NSP-Minnesota does not believe a material change will occur as the resulting deferred tax liabilities are likely to be offset by increased deferred tax assets associated with net operating losses.

NSP-Minnesota has also filed a plan for any potential refund that treats the multi-year case as a single period. In January 2015, the DOC and Office of Attorney General (OAG) filed comments on the plan. The DOC recommended an alternative option that views each year of the multi-year case separately, which would result in lower 2015 revenues.

A current regulatory liability representing NSP-Minnesota's best estimate of a refund obligation for 2014 associated with interim rates was recorded as of Dec. 31, 2014. The estimated amount is generally consistent with the ALJ recommendation.

The MPUC is expected to deliberate on March 26, 2015 and a final order is anticipated in the second quarter of 2015.

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 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.

NSP-Minnesota filed a report to support the 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 NRC licensing related requests over the five-plus year application process.

The cost deviation is in line with similar nuclear upgrade projects undertaken by other utilities. In addition, the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and as of Dec. 31, 2014, has fully complied with the NRC's license requirements for higher power levels.

In July 2014, the DOC filed testimony and recommended a disallowance of recovery of approximately $71.5 million of project costs on a Minnesota jurisdictional basis. This equates to a total NSP System disallowance of approximately $94 million.

In August 2014, the OAG filed rebuttal testimony and recommended a disallowance of recovery of $321 million for the entire NSP System (based on a total capitalized cost of $748 million), and no return on $107 million. NSP-Minnesota believes the costs of the project were prudent and its decisions and actions do not warrant a disallowance.

At this time the ALJ's report is expected to be issued in February with deliberations of the case to occur as scheduled in March.

A final MPUC order is anticipated in the second quarter of 2015. The MPUC decision for the Monticello prudence review is expected to be reflected in the final results of NSP-Minnesota's pending Minnesota 2014 Multi-Year electric rate case.

NSP-Minnesota's Letter in Support of e21 Initiative — In December 2014, a collaborative report was issued in Minnesota by a diverse stakeholder group known as the e21 Initiative. The e21 report released a set of recommendations that are intended to act as a blueprint for a new customer-centric, performance-based regulatory approach.

Following the e21 report, NSP-Minnesota filed with the MPUC a plan for supporting the e21 Initiative, which includes the following key objectives:

- Leading the effort to reduce carbon emissions 40 percent by 2030;
- Advancing distribution grid modernization;
- Providing our customers with a platform of innovative services and product offerings; and
- Implementing a new regulatory framework that provides both predictable rates for customers and a more timely and nimble review while retaining key benefits of the existing process, thus freeing time for regulatory agencies, stakeholders and utilities to focus on achieving policy objectives.

NSP-Minnesota plans to work with the MPUC and various stakeholders during 2015 to continue the dialogue and implementation of the e21 Initiative and proposals presented by NSP-Minnesota.

NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Resource Plan with the MPUC, proposing to achieve a 40 percent reduction in carbon emissions from 2005 levels through the significant addition of renewables, continued commitment to specific conservation improvement program annual achievements, and the continued operation of its existing cost-effective thermal generation. The plan positions NSP-Minnesota to be responsive to future environmental requirements and market trends, builds on the significant investments already made in the NSP System, and acknowledges the divergence in state energy policies within the NSP System. Key points of the resource plan include:

- Adding 600 MW of wind by 2020 and 1,200 MW by 2027, bringing total wind power on the NSP System to over 3,600 MW;
- Adding 187 MW of large-scale solar energy by 2016 and an additional 1,700 MW of large-scale solar and 500 MW of customer-driven small-scale solar; bringing total solar power on the NSP System to approximately 2,400 MW;

- Operating the Monticello and PI nuclear plants through their current licenses; and
- Continuing to run Sherco Units 1 and 2 with gradually decreasing reliance through 2030.

The resource plan brings together other pending resource proceedings including the Competitive Acquisition Plan (CAP), in which the MPUC required NSP-Minnesota to add capacity to its system to meet a resource need in the 2018-2019 time frame, as follows:

- Enter into an agreement for 100 MW of distributed solar with Geronimo Energy, LLC;
- Enter into an agreement with Calpine Corporation for a 345 MW expansion at its Mankato Energy Center; and
- Construct a 215 MW Black Dog Unit 6 combustion turbine.

NSP-Minnesota also proposed use of a collaborative stakeholder process to guide its five-year action plan, and to facilitate the necessary update of its resource analysis to incorporate the December 2014 CAP outcomes and significantly higher than expected response to its Community Solar Gardens program.

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In August 2014, NSP-Minnesota filed 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 assessments 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 requested 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 which is the 2015 portion of a five year amortization. In December 2014, the MPUC approved the GUIC rider for $14.7 million, with an effective date of Feb. 1, 2015.

NSP-Minnesota – South Dakota 2015 Electric Rate Case — In June 2014, NSP-Minnesota filed a request with the South Dakota Public Utilities Commission (SDPUC) 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 Transmission Cost Recovery (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 case is in the discovery phase and further procedure scheduling may be established, as necessary during the first quarter of 2015. Final rates are anticipated to be effective mid-2015.

NSP-Wisconsin – 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 was 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 were 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.

In December 2014, the PSCW issued its order approving an overall increase in NSP-Wisconsin's electric rates of approximately $14.2 million, or 2.2 percent, reflecting the updated November forecast for fuel and purchased power costs. The PSCW order was consistent with the agreement reached by the parties, as described above. The new rates were effective Jan. 1, 2015.

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 is anticipated to increase revenue recovery by approximately $34.2 million in 2016 and then decline to approximately $29.9 million in 2017. The rate filing was based on a 2015 forecast 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 would transfer approximately $19.9 million from the transmission rider to base rates, which would not impact customer bills. The rider would recover incremental investment and expenses associated with the CACJA project to retire certain coal plants, add pollution control equipment to other existing coal units and add natural gas generation.

In November 2014, several parties filed answer testimony, including the CPUC Staff (Staff) and the Office of Consumer Counsel (OCC). The Staff's position was based on an ROE of 9.11 percent and a 51.24 percent equity ratio. In addition, the Staff proposed that costs associated with the CACJA project be recovered through a rider mechanism. The OCC recommended an ROE of 9.10 percent, a 52.70 percent equity ratio and that a portion of the costs associated with the CACJA project be recovered in base rates and the remainder through a rider mechanism.

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.

On Jan. 23, 2015, PSCo and intervenors filed a comprehensive settlement agreement, subject to CPUC approval, which would result in an overall 2015 revenue increase of approximately $53.3 million, or 1.87 percent. The settlement is based on a 2013 HTY, an ROE of 9.83 percent and an equity ratio of 56 percent. It includes the implementation of a forward-looking CACJA rider, effective Jan. 1, 2015, a forward-looking transmission cost adjustment (TCA) rider, effective Feb. 13, 2015 and tracking mechanisms for pension expense and property taxes. The agreement also includes 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 earnings test principles are based primarily on those established in the previous rate case.

The Staff and OCC's recommendations, PSCo's rebuttal testimony and the terms of the settlement agreement are summarized as follows:

2015 Rate Request (Millions of Dollars)	Staff	OCC	PSCo Rebuttal	Settlement Agreement
PSCo's filed rate request	$ 136.0	$ 136.0	$ 136.0	$ 136.0
Transfer from TCA rider to base rates	19.9	19.9	19.9	19.9
PSCo's filed revenue requirement deficiency	155.9	155.9	155.9	155.9
Lower ROE	(69.1)	(66.5)	(6.2)	(27.9)
Capital structure	(20.9)	(23.7)	—	—
Rate base adjustments (largely the removal of prepaid pension asset)	(20.8)	2.3	—	—
Adjustment to an HTY	(82.5)	(82.5)	—	(23.9)
Adjustment to use 13-month average rate base	(26.1)	(22.0)	—	—
Rate base adjustments for known and measurable plant through September 2014	21.9	—	—	—
O&M expense adjustments	(7.2)	(16.6)	—	—
Depreciation	—	(3.8)	—	—
Property taxes	—	(12.1)	(5.3)	(5.3)
Remove CACJA from base rates	(62.4)	—	(98.7)	(98.7)
Updated sales forecast	—	—	(15.2)	(15.2)
Prepaid pension amortization	—	—	—	9.5
Non-specified settlement adjustments	—	—	—	(31.7)
Other, net	0.1	0.1	(2.1)	(2.1)
Total base rate (decrease) increase	(111.1)	(68.9)	28.4	(39.4)
CACJA rider mechanism	54.2	—	98.7	97.0
TCA rider mechanism — 2015 forecast test year	—	—	—	15.6
Transfer from TCA rider to base rates	(19.9)	(19.9)	(19.9)	(19.9)
Total revenue impact	$ (76.8)	$ (88.8)	$ 107.2	$ 53.3

In addition to the revenue reflected in the table above, PSCo estimates that it will defer approximately $3.1 million of additional expenses in 2015 as a result of the settlement.

In its original rate case request, PSCo proposed to shorten the depreciable lives for certain assets, which would have resulted in a material increase in depreciation expense. As a result of the settlement, PSCo will not implement the depreciation changes, but will instead file a standalone case to address depreciation, amortization and decommissioning in early 2016. The results of the depreciation case will become effective as part of the 2018 electric rate case.

The CPUC is expected to issue a decision regarding the settlement in the first quarter of 2015 and final rates would be effective Feb. 13, 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 2012-2014. In April 2014, PSCo filed its 2013 earnings test with the CPUC proposing a refund obligation of $45.7 million to electric customers. This tariff was approved by the CPUC in July 2014. As of Dec. 31, 2014, PSCo has also recognized management's best estimate of the expected customer refund obligation for the 2014 earnings test of $74.0 million.

PSCo – Boulder, Colo. Municipalization **—** PSCo's franchise agreement with the City of Boulder (Boulder) expired in December 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 2013, the CPUC 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. In January 2015, the Boulder District Court affirmed the CPUC decision.

Boulder sent PSCo an offer of $128 million for certain portions of PSCo's transmission and distribution business. PSCo has notified Boulder that its offer was deficient. 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. PSCo filed a motion to dismiss the petition based upon the CPUC's ruling that it must determine the appropriate system separations prior to Boulder filing its condemnation case. PSCo's motion to dismiss is currently pending.

In August 2014, PSCo filed a petition with the FERC requesting an order requiring that Boulder's attempt to acquire PSCo's transmission and distribution facilities by condemnation requires prior FERC approval under the Federal Power Act. Boulder opposed the petition in October 2014. In December 2014, the FERC issued an order granting PSCo's petition.

If Boulder is allowed to proceed with its condemnation petition and 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 FERC.

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the Public Utility Commission of Texas (PUCT) seeking an overall increase in annual revenue of approximately $64.75 million, or 6.7 percent. The filing is 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 $1.56 billion and an equity ratio of 53.97 percent.

As part of its request, SPS is seeking a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of $442 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	$ 29.60
Depreciation expense	13.90
Wholesale load reductions	12.00
Purchased power capacity costs	3.20
Other, net	6.05
Total	$ 64.75

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

- Intervenor Direct Testimony — April 1, 2015;
- Staff Direct Testimony — April 8, 2015;
- Staff and Intervenor Cross-Rebuttal Testimony — April 22, 2015;

- Rebuttal Testimony — April 24, 2015; and
- Evidentiary Hearing — May 11, 2015.

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

SPS – Texas 2014 Electric Rate Case — In January 2014, SPS filed a retail electric rate case in Texas seeking 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 to zero when the final base rates become effective. In April 2014, SPS revised its request to a net increase of $48.1 million.

The rate filing was based on an HTY 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.

In September 2014, SPS, PUCT staff, and intervenors filed a non-unanimous settlement agreement which would increase SPS' rates by $37 million, or 3.5 percent, retroactive to June 1, 2014. Starting Oct. 1, 2014, SPS began collecting the rate increase through interim rates subject to refund. SPS expects to recover the rate increase for June through September 2014 through a separate surcharge, for which it has recognized approximately $15.4 million of revenue in 2014. In December 2014, the PUCT approved the settlement and authorized the surcharge.

In January 2015, SPS filed an application to implement a surcharge of approximately $15.6 million, including interest, to be recovered from March through June 2015, subject to a true-up.

Transmission-only Subsidiaries (TransCos) — In 2014, Xcel Energy formed the Xcel Energy Transmission Holding Company, LLC and two of its TransCo subsidiaries that will participate in the Midcontinent Independent System Operator, Inc. (MISO) and Southwest Power Pool, Inc. (SPP) competitive bidding processes. Transmission assets held by these entities will be subject to FERC jurisdiction. Xcel Energy has also formed an additional TransCo subsidiary to seek transmission projects in the western United States.

<u>MISO</u>
Xcel Energy Transmission Development Company, LLC (XETD) was approved as a non-transmission owning member in MISO in April 2014, and a qualified transmission developer (QTD) in December 2014. This allows XETD to competitively bid for MISO transmission projects starting in 2015 or 2016. Additionally, NSP-Minnesota and NSP-Wisconsin have been approved to competitively bid for MISO transmission projects as QTDs starting in 2015.

<u>SPP</u>
In September 2014, SPP determined that Xcel Energy Southwest Transmission Company, LLC's (XEST) participant application was complete. This allows XEST to competitively bid for SPP transmission projects starting in 2015.

In November 2014, the FERC approved XETD and XEST's forward-looking transmission formula rates that will apply in their respective jurisdictions with an effective date retroactive to Nov. 1, 2014. The FERC approved the following items requested in the TransCo rate filings:

- A capital structure based on 55 percent equity and 45 percent debt for both TransCos;
- Deferral of start-up costs for future recovery in rates, subject to a future filing prior to actual recovery;
- XETD's request for a base ROE using the currently applicable MISO regional rate of 12.38 percent, subject to any potential modifications resulting from a pending ROE complaint against the MISO transmission owners; and
- XEST's base ROE of 10.64 percent. However, the FERC suspended the proposed ROE and the ROE will be subject to refund and potential modifications resulting from settlement judge or hearing procedures set for 2015. Also, the FERC granted XEST's request for a 50 basis point adder for membership in SPP.

No party filed for rehearing of the XETD and XEST orders. In January 2015, XETD and XEST submitted compliance filings to the orders. The first settlement conference for the XEST ROE issue was held Jan. 6, 2015. The next settlement conference is scheduled for March 10, 2015.

<u>WestConnect</u>
Xcel Energy West Transmission Company executed the WestConnect planning participation agreement in January 2015, and is participating in the WestConnect regional planning process as an independent transmission developer or owner.

Note 5. SPS FERC Orders

In August 2013, the FERC issued an order on rehearing related to a 2004 complaint case brought by Golden Spread Electric Cooperative, Inc., a wholesale cooperative customer, and Public Service Company of New Mexico (PNM) and an Order on Initial Decision in a subsequent 2006 production rate case filed by SPS.

The original complaint included two key components: 1) PNM's claim regarding inappropriate allocation of fuel costs and 2) a base rate complaint, including the appropriate demand-related cost allocator. The FERC previously determined that the allocation of fuel costs and the demand-related cost allocator utilized by SPS was appropriate.

In the August 2013 Orders, the FERC clarified its previous ruling on the allocation of fuel costs and reaffirmed that the refunds in question should only apply to firm requirements customers and not PNM's contractual load. The FERC also reversed its prior demand-related cost allocator decision. The FERC stated that it had erred in its initial analysis and concluded that the SPS system was a 3 coincident peak (CP) rather than a 12CP system.

In September 2013, SPS filed a request for rehearing of the FERC ruling on the CP allocation and refund decisions. SPS asserted that the FERC applied an improper burden of proof and that precedent did not support retroactive refunds. PNM also requested rehearing of the FERC decision not to reverse its prior ruling.

In October 2013, the FERC issued orders further considering the requests for rehearing. These matters are currently pending the FERC's action. If unsuccessful in its rehearing request, SPS will have the opportunity to file rate cases with the FERC and its retail jurisdictions seeking to change all customers to a consistent CP allocation method.

As of Dec. 31, 2013, SPS had accrued \$44.5 million related to the August 2013 Orders and an additional \$5.9 million of principal and interest was accrued during 2014. Pending the timing and resolution of this matter, the annual impact to revenues could decrease to \$4 million on June 1, 2015.

Note 6. 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 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 decline approximately 2.0 percent.
- Capital rider revenue is projected to increase by \$160 million to \$170 million over 2014 levels. The projected capital rider revenue reflects the transfer of the CACJA project from base rates to the rider per the settlement in the Colorado electric rate case. The settlement is pending CPUC approval.
- 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 \$160 million to \$180 million over 2014 levels, reflecting the originally proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota's moderation plan in the Minnesota electric rate case.
- 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 \$35 million to \$45 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 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.

Note 7. Non-GAAP Reconciliation

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating the company and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

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

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(Thousands of Dollars)	**2014**	**2013**	**2014**	**2013**
Ongoing earnings	$ 196,339	$ 150,055	$ 1,021,306	$ 968,425
SPS FERC complaint case orders	—	—	—	(20,191)
GAAP earnings	**$ 196,339**	**$ 150,055**	**$ 1,021,306**	**$ 948,234**

SPS FERC Orders — As a result of the two orders issued in August 2013 by the FERC for a potential SPS customer refund, a pre-tax charge of $36 million was recorded in 2013. Of this amount, approximately $30 million ($26 million revenue reduction and $4 million of interest) was attributable to periods prior to 2013 and not representative of ongoing earnings. As such, GAAP earnings include the total after tax amount of $24.4 million and ongoing earnings exclude $20.2 million. See Note 5.

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

	Three Months Ended Dec. 31	
	2014	**2013**
Operating revenues:		
Electric and natural gas	$ 2,907,465	$ 2,710,451
Other	21,163	20,371
Total operating revenues	2,928,628	2,730,822
Net income	$ 196,339	$ 150,055
Weighted average diluted common shares outstanding	506,799	498,802
Components of EPS — Diluted [a]		
Regulated utility	$ 0.42	$ 0.33
Xcel Energy Inc. and other costs	(0.03)	(0.03)
Ongoing diluted EPS	**0.39**	**0.30**
SPS FERC complaint case orders [b]	—	—
GAAP diluted EPS	**$ 0.39**	**$ 0.30**

	Twelve Months Ended Dec. 31	
	2014	**2013**
Operating revenues:		
Electric and natural gas	$ 11,608,628	$ 10,838,724
Other	77,507	76,198
Total operating revenues	11,686,135	10,914,922
Net income	$ 1,021,306	$ 948,234
Weighted average diluted common shares outstanding	504,117	496,532
Components of EPS — Diluted [a]		
Regulated utility	$ 2.14	$ 2.09
Xcel Energy Inc. and other costs	(0.11)	(0.14)
Ongoing diluted EPS	**2.03**	**1.95**
SPS FERC complaint case orders [b]	—	(0.04)
GAAP diluted EPS	**$ 2.03**	**$ 1.91**
Book value per share	$ 20.20	$ 19.21

(a) See Note 2.
(b) See Note 7.