414 Nicollet Mall
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Jan. 30, 2014

XCEL ENERGY
2013 YEAR END EARNINGS REPORT

- Ongoing 2013 earnings per share were $1.95 compared with $1.82 per share in 2012.
- GAAP (generally accepted accounting principles) 2013 earnings per share were $1.91 compared with $1.85 per share in 2012.
- Xcel Energy reaffirms 2014 ongoing earnings guidance of $1.90 to $2.05 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2013 GAAP earnings of $948 million, or $1.91 per share, compared with 2012 GAAP earnings of $905 million, or $1.85 per share.

Ongoing earnings, which exclude adjustments for certain items, were $1.95 per share for 2013 compared with $1.82 per share in 2012. Ongoing earnings increased as a result of higher electric and gas margins due to rate increases in various states, the impact of favorable colder weather on our natural gas business and reduced interest charges. These positive factors were partially offset by planned increases in operating and maintenance expenses 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. 2012 GAAP earnings reflect the $0.03 per share positive impact for a tax benefit associated with federal subsidies for prescription drug plans. Both items are excluded from ongoing earnings.

"It was a successful year from both an operational and financial perspective," stated Ben Fowke, Chairman, President and Chief Executive Officer. "The investments we have made in our system were once again tested by severe storms experienced across our service territories. We were well prepared, meeting all of our customer energy requirements with minimal disruptions. This would not have been possible without the tremendous efforts of our skilled and dedicated employees. Further, we successfully completed several major construction projects including the Monticello nuclear extended life and uprate project as well as the Prairie Island steam generator replacement. We are set to increase our future wind production by 40 percent, which is expected to provide significant fuel savings to our customers over the next twenty years. Financially, we delivered earnings within our guidance range for the ninth consecutive year and raised the dividend for the tenth consecutive year."

"We are reaffirming our 2014 ongoing earnings guidance of $1.90 to $2.05 per share. Our credit ratings remain strong, we will continue to make smart investments and we are committed to improving our regulatory compact by proposing rate mitigation plans and measures such as multi-year rate cases. I believe we are a premium company, well-positioned for the future," said Fowke.

Earnings Adjusted for Certain Items (Ongoing Earnings Per Share)

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

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings (Loss) Per Share	**2013**	**2012**	**2013**	**2012**
Ongoing diluted earnings per share	**$ 0.30**	**$ 0.29**	**$ 1.95**	**$ 1.82**
SPS 2004 FERC complaint case orders [(a)]	—	—	(0.04)	—
Prescription drug tax benefit [(a)]	—	—	—	0.03
GAAP diluted earnings per share	**$ 0.30**	**$ 0.29**	**$ 1.91**	**$ 1.85**

(a) See Note 8.

At 10:00 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:	(877) 941-0844
International Dial-In:	(480) 629-9835
Conference ID:	4660465

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 1:00 p.m. CST on Jan. 30 through 11:59 p.m. CST on Jan. 31.

Replay Numbers	
US Dial-In:	(800) 406-7325
International Dial-In:	(303) 590-3030
Access Code:	4660465#

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, 2012 and Quarterly Reports on Form 10-Q for the quarters ended March 31, June 30 and Sept. 30, 2013.

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

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

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
	2013	2012	2013	2012
Operating revenues				
Electric	$ 2,122,047	$ 2,010,976	$ 9,034,045	$ 8,517,296
Natural gas	588,404	520,513	1,804,679	1,537,374
Other	20,371	19,646	76,198	73,553
Total operating revenues	2,730,822	2,551,135	10,914,922	10,128,223
Operating expenses				
Electric fuel and purchased power	984,641	898,752	4,018,672	3,623,935
Cost of natural gas sold and transported	379,764	323,495	1,082,751	880,939
Cost of sales — other	9,491	8,568	33,323	29,067
Operating and maintenance expenses	606,439	599,917	2,273,532	2,176,095
Conservation and demand side management program expenses	68,438	69,285	260,726	260,527
Depreciation and amortization	256,732	231,689	977,863	926,053
Taxes (other than income taxes)	99,735	103,032	420,500	408,924
Total operating expenses	2,405,240	2,234,738	9,067,367	8,305,540
Operating income	325,582	316,397	1,847,555	1,822,683
Other (expense) income, net	(959)	1,222	2,972	6,175
Equity earnings of unconsolidated subsidiaries	7,641	7,821	30,020	29,971
Allowance for funds used during construction — equity	24,536	18,336	87,683	62,840
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,077, $5,961, $30,135, and $24,087, respectively	144,173	144,150	575,199	601,552
Allowance for funds used during construction — debt	(10,728)	(10,586)	(39,179)	(35,315)
Total interest charges and financing costs	133,445	133,564	536,020	566,237
Income before income taxes	223,355	210,212	1,432,210	1,355,432
Income taxes	73,300	70,042	483,976	450,203
Net income	$ 150,055	$ 140,170	$ 948,234	$ 905,229
Weighted average common shares outstanding:				
Basic	498,499	488,428	496,073	487,899
Diluted	498,802	489,136	496,532	488,434
Earnings per average common share:				
Basic	$ 0.30	$ 0.29	$ 1.91	$ 1.86
Diluted	0.30	0.29	1.91	1.85
Cash dividends declared per common share	$ 0.28	$ 0.27	$ 1.11	$ 1.07

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 earnings and earnings per share (EPS) 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 that 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 Summary

The following table summarizes the diluted earnings per share for Xcel Energy and subsidiaries:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings (Loss) Per Share	**2013**	**2012**	**2013**	**2012**
Public Service Company of Colorado (PSCo)	$ 0.15	$ 0.16	$ 0.91	$ 0.90
NSP-Minnesota	0.12	0.13	0.79	0.70
Southwestern Public Service Company (SPS)	0.04	0.01	0.23	0.22
NSP-Wisconsin	0.01	0.02	0.12	0.10
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.04	0.04
Regulated utility	0.33	0.33	2.09	1.96
Xcel Energy Inc. and other costs	(0.03)	(0.04)	(0.14)	(0.14)
Ongoing diluted earnings per share	0.30	0.29	1.95	1.82
SPS 2004 FERC complaint case orders [(a)]	—	—	(0.04)	—
Prescription drug tax benefit [(a)]	—	—	—	0.03
GAAP diluted earnings per share	**$ 0.30**	**$ 0.29**	**$ 1.91**	**$ 1.85**

(a) See Note 8.

PSCo — PSCo's ongoing earnings increased $0.01 per share for 2013. Ongoing earnings increased as a result of higher gas and electric margins primarily due to rate increases, the impact of cooler weather on natural gas margins and lower interest charges, partially offset by higher depreciation, operating and maintenance (O&M) expenses and customer refunds related to the 2013 electric earnings test refund obligation.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.09 per share for 2013. Ongoing earnings were positively impacted by electric rate increases in Minnesota and South Dakota, interim rates subject to refund in North Dakota, the impact of cooler winter weather and lower interest charges. These items were partially offset by higher O&M expenses.

SPS — SPS' ongoing earnings increased $0.01 per share for 2013. Electric rate increases in Texas and the gain associated with the sale of certain transmission assets to Sharyland Distribution and Transmission Services, LLC (Sharyland) were partially offset by higher depreciation.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.02 per share for 2013. Higher ongoing earnings from electric and natural gas rates and cooler winter weather were partially offset by higher O&M expenses and depreciation.

The following table summarizes significant components contributing to the changes in 2013 EPS compared with the same period in 2012, which are discussed in more detail later in the release:

Diluted Earnings (Loss) Per Share	Three Months Ended Dec. 31	Twelve Months Ended Dec. 31
2012 GAAP diluted earnings per share	**$ 0.29**	**$ 1.85**
Prescription drug tax benefit [a]	—	(0.03)
2012 ongoing diluted earnings per share	**0.29**	**1.82**
Components of change — 2013 vs. 2012		
Higher electric margins (excludes impact of SPS 2004 FERC complaint case orders) [a]	0.03	0.18
Higher natural gas margins	0.01	0.08
Higher Allowance for Funds Used During Construction (AFUDC) — equity	0.01	0.05
Lower interest charges (excludes impact of SPS 2004 FERC complaint case orders) [a]	—	0.04
Gain on sale of transmission assets (included in O&M expenses) [b]	0.02	0.02
Higher O&M expenses (excludes gain on sale of transmission assets) [b]	(0.03)	(0.14)
Higher depreciation and amortization	(0.03)	(0.06)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.01)	(0.03)
Higher taxes (other than income taxes)	—	(0.01)
Other, net	0.01	—
2013 ongoing diluted earnings per share	**0.30**	**1.95**
SPS 2004 FERC complaint case orders [a]	—	(0.04)
2013 GAAP diluted earnings per share	**$ 0.30**	**$ 1.91**

The following table summarizes the return on equity for Xcel Energy and subsidiaries:

Return on equity — 2013	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2013 ongoing return on equity	9.66%	9.24%	9.03%	10.61%	10.50%
SPS 2004 FERC complaint case orders [a]	—	—	(1.54)	—	(0.22)
2013 GAAP return on equity	9.66%	9.24%	7.49%	10.61%	10.28%

Return on equity — 2012	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2012 ongoing return on equity	9.92%	8.77%	9.44%	9.62%	10.24%
Prescription drug tax benefit [a]	0.38	—	—	—	0.19
2012 GAAP return on equity	10.30%	8.77%	9.44%	9.62%	10.43%

(a) See Note 8.
(b) See Note 5.

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 Dec. 31			Twelve Months Ended Dec. 31		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
HDD	8.3%	(6.7)%	15.2%	6.5%	(15.9)%	25.8%
CDD [(a)]	N/A	N/A	N/A	24.7	46.1	(13.6)
THI [(a)]	N/A	N/A	N/A	21.8	36.1	(9.7)

(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		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
Retail electric	$ 0.009	$ (0.002)	$ 0.011	$ 0.088	$ 0.081	$ 0.007
Firm natural gas	0.007	(0.003)	0.010	0.021	(0.033)	0.054
Total	$ 0.016	$ (0.005)	$ 0.021	$ 0.109	$ 0.048	$ 0.061

Sales Growth — The following tables summarize Xcel Energy's sales growth for actual and weather-normalized sales in 2013:

	Three Months Ended Dec. 31	
	Actual	Weather Normalized
Electric residential	2.3%	—%
Electric commercial and industrial	1.6	1.5
Total retail electric sales	1.8	1.1
Firm natural gas sales [(a)]	9.7	2.0

	Twelve Months Ended Dec. 31		Twelve Months Ended Dec. 31 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	1.1%	0.2%	1.4%	0.5%
Electric commercial and industrial	—	0.1	0.3	0.4
Total retail electric sales	0.3	0.1	0.6	0.4
Firm natural gas sales [(a)]	21.3	3.3	21.9	3.8

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

Electric — 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 Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	**2013**	**2012**	**2013**	**2012**
Electric revenues	$ 2,122	$ 2,011	$ 9,034	$ 8,517
Electric fuel and purchased power	(985)	(899)	(4,019)	(3,624)
Electric margin	$ 1,137	$ 1,112	$ 5,015	$ 4,893

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

(Millions of Dollars)	**Three Months Ended Dec. 31 2013 vs. 2012**	**Twelve Months Ended Dec. 31 2013 vs. 2012**
Retail rate increases [(a)]	$ 52	$ 229
Transmission revenue, net of costs	6	36
Non-fuel riders	8	18
Estimated impact of weather	8	7
PSCo earnings test refund obligation	(23)	(43)
Conservation and demand side management (DSM) program incentives	1	(24)
Firm wholesale	(4)	(24)
Trading margin	(4)	(12)
SPS 2004 FERC complaint case orders [(b)]	(2)	(6)
Other, net	(17)	(33)
Total increase in ongoing electric margin	25	148
SPS 2004 FERC complaint case orders [(b)]	—	(26)
Total increase in GAAP electric margin	$ 25	$ 122

(a) The retail rate increases include final rates in Minnesota, Colorado, Wisconsin, South Dakota and Texas and interim rates, subject to refund, in North Dakota. The Minnesota rate increase is net of a provision for customer refunds of $15 million for the fourth quarter of 2013 and $131 million for the twelve months ended Dec. 31, 2013 based on the final rate order received for the 2013 electric rate case. Due to the order, there was a reduction in revenues and expenses of approximately $10 million, primarily related to depreciation of $8 million and O&M expenses of $2 million in the fourth quarter of 2013. There was a reduction in revenues and expenses of approximately $40 million, primarily related to depreciation of $32 million and O&M expense of $8 million in 2013.

(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 6.

Natural Gas — 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 Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	**2013**	**2012**	**2013**	**2012**
Natural gas revenues	$ 588	$ 521	$ 1,805	$ 1,537
Cost of natural gas sold and transported	(380)	(323)	(1,083)	(881)
Natural gas margin	$ 208	$ 198	$ 722	$ 656

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

(Millions of Dollars)	**Three Months Ended Dec. 31 2013 vs. 2012**	**Twelve Months Ended Dec. 31 2013 vs. 2012**
Estimated impact of weather	$ 8	$ 42
Retail rate increases (Colorado and Wisconsin)	6	15
Retail sales growth	2	9
Conservation and DSM program incentive	4	5
Conservation and DSM program revenues (offset by expenses)	—	4
Other, net	(10)	(9)
Total increase in natural gas margin	$ 10	$ 66

O&M Expenses — O&M expenses increased $6.5 million, or 1.1 percent, for the fourth quarter of 2013 and $97.4 million, or 4.5 percent, for 2013 compared with the same periods in 2012. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	**Three Months Ended Dec. 31 2013 vs. 2012**	**Twelve Months Ended Dec. 31 2013 vs. 2012**
Electric and gas distribution expenses	$ 12	$ 44
Nuclear plant operations and amortization	5	33
Transmission costs	2	13
Employee benefits	3	7
Gain on sale of transmission assets (See Note 5)	(14)	(14)
Other, net	(1)	14
Total increase in O&M expenses	$ 7	$ 97

- Electric and gas distribution expenses were primarily driven by increased maintenance activities due to vegetation management, storms and outages;
- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants;
- Increased transmission costs were related to higher substation maintenance expenditures and reliability costs; and
- Higher employee benefits related primarily to increased pension expense.

Depreciation and Amortization — Depreciation and amortization increased $25.0 million, or 10.8 percent, for the fourth quarter of 2013 and $51.8 million, or 5.6 percent, for 2013 compared with the same periods in 2012. The increases are primarily attributable to normal system expansion, which was partially offset by reductions related to the final rate order received for the 2013 Minnesota electric rate case that reduced depreciation expense by approximately $8 million for the fourth quarter and $32 million for 2013.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) decreased $3.3 million, or 3.2 percent, for the fourth quarter of 2013 and increased $11.6 million, or 2.8 percent, for 2013 compared with the same periods in 2012. The annual increase is due to higher property taxes primarily in Colorado and Texas.

AFUDC, Equity and Debt — AFUDC increased $6.3 million for the fourth quarter of 2013 and $28.7 million for 2013 compared with the same periods in 2012. The increases are primarily due to construction related to the Clean Air Clean Jobs Act (CACJA) and the expansion of transmission facilities.

Interest Charges — Interest charges remained flat for the fourth quarter of 2013 and decreased $26.4 million, or 4.4 percent, for 2013 compared with the same periods in 2012. The decrease is primarily due to refinancings at lower interest rates. This was partially offset by higher long-term debt levels, $4 million of interest associated with the customer refund at SPS based on the August 2013 FERC orders, $5 million of interest associated with customer refunds in Minnesota for the 2013 electric rate case 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 $3.3 million for the fourth quarter of 2013 compared with the same period in 2012. The increase in income tax expense was primarily due to higher pretax earnings. The effective tax rate (ETR) was 32.8 percent for the fourth quarter of 2013 compared with 33.3 percent for the same period in 2012.

Income tax expense increased $33.8 million for 2013 compared with 2012. The increase in income tax expense was primarily due to higher pretax earnings in 2013, a tax benefit for a carryback in 2012 and for the restoration in 2012 of a portion of the tax benefit associated with federal subsidies for prescription drug plans that was previously written off in 2010. These were partially offset in 2013 by a tax benefit for a carryback claim related to 2013, research and experimentation credits and increased permanent plant-related reductions. The ETR was 33.8 percent for 2013 compared with 33.2 percent for 2012. The higher ETR for 2013 was primarily due to the adjustments referenced above.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	Dec. 31, 2013	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.3	1%
Short-term debt	0.7	3
Long-term debt	10.9	51
Total debt	11.9	55
Common equity	9.6	45
Total capitalization	$ 21.5	100%

Credit Facilities — As of Jan. 28, 2014, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 800.0	$ 516.0	$ 284.0	$ 0.2	$ 284.2
PSCo	700.0	108.4	591.6	1.0	592.6
NSP-Minnesota	500.0	364.9	135.1	0.6	135.7
SPS	300.0	123.0	177.0	0.9	177.9
NSP-Wisconsin	150.0	89.0	61.0	0.7	61.7
Total	$ 2,450.0	$ 1,201.3	$ 1,248.7	$ 3.4	$ 1,252.1

(a) These credit facilities expire in July 2017.
(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).

On Nov. 14, 2013, Fitch upgraded both PSCo senior unsecured debt and PSCo senior secured debt by one notch.

As of Jan. 28, 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	Baa1	BBB+	BBB+
Xcel Energy Inc.	Commercial Paper	P-2	A-2	F2
NSP-Minnesota	Senior Unsecured Debt	A3	A-	A
NSP-Minnesota	Senior Secured Debt	A1	A	A+
NSP-Minnesota	Commercial Paper	P-2	A-2	F2
NSP-Wisconsin	Senior Unsecured Debt	A3	A-	A
NSP-Wisconsin	Senior Secured Debt	A1	A	A+
NSP-Wisconsin	Commercial Paper	P-2	A-2	F2
PSCo	Senior Unsecured Debt	Baa1	A-	A
PSCo	Senior Secured Debt	A2	A	A+
PSCo	Commercial Paper	P-2	A-2	F2
SPS	Senior Unsecured Debt	Baa2	A-	BBB+
SPS	Senior Secured Debt	A3	A-	A-
SPS	Commercial Paper	P-2	A-2	F2

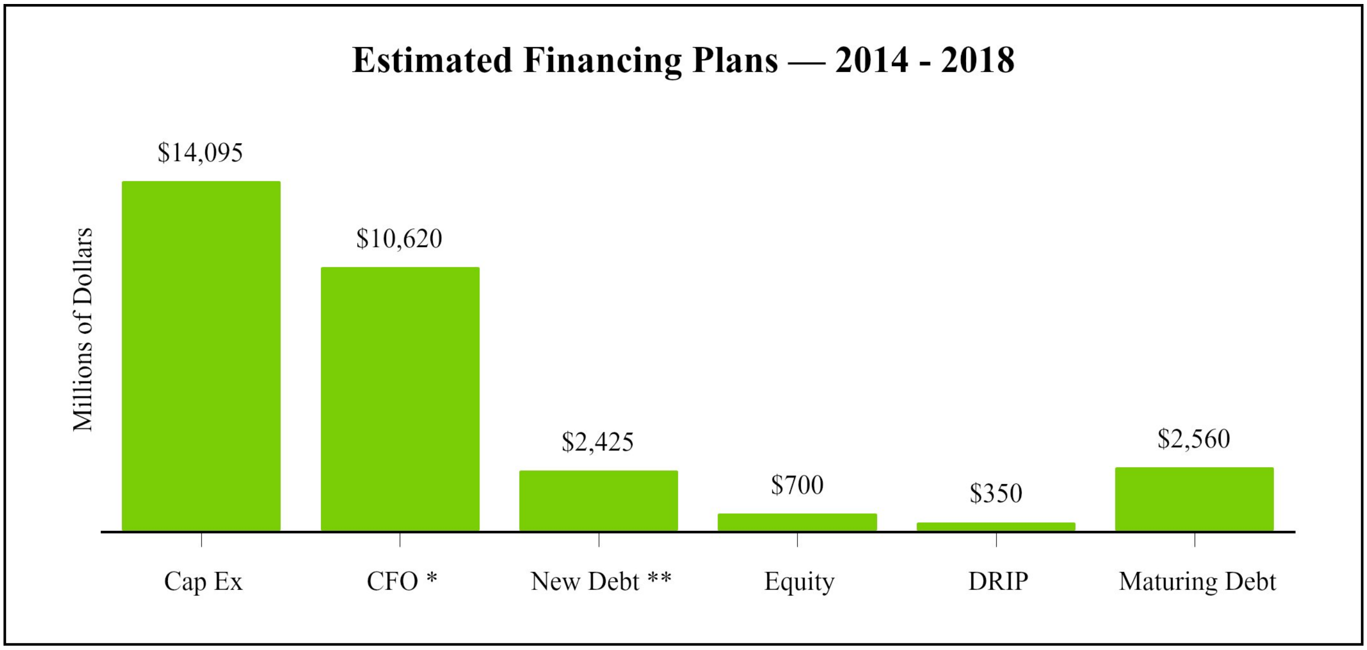
The highest credit rating for debt is Aaa/AAA and the lowest investment grade rating is Baa3/BBB-. The highest rating for commercial paper is P-1/A-1/F-1 and the lowest rating is P-3/A-3/F-3. A security rating is not a recommendation to buy, sell or hold securities. Ratings are subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Capital Expenditures — The current estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2014 through 2018 are shown in the table below.

	Actual	Forecast				
(Millions of Dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
By Subsidiary						
NSP-Minnesota	$ 1,505	$ 1,090	$ 1,620	$ 955	$ 885	$ 805
PSCo	1,074	985	845	795	770	815
SPS	555	525	520	610	770	790
NSP-Wisconsin	217	290	210	265	275	275
WYCO	8	—	—	—	—	—
Total capital expenditures	$ 3,359	$ 2,890	$ 3,195	$ 2,625	$ 2,700	$ 2,685
By Function	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Electric transmission	$ 1,073	$ 950	$ 770	$ 790	$ 945	$ 1,035
Electric generation	1,116	715	1,235	560	550	470
Electric distribution	551	510	560	595	605	610
Natural gas	316	365	340	345	300	320
Nuclear fuel	90	140	100	135	135	75
Other	213	210	190	200	165	175
Total capital expenditures	$ 3,359	$ 2,890	$ 3,195	$ 2,625	$ 2,700	$ 2,685
By Project	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Other major transmission projects	$ 335	$ 370	$ 265	$ 330	$ 420	$ 385
CapX2020 transmission project	330	255	125	5	—	—
PSCo CACJA	350	250	85	10	—	—
Natural gas pipeline replacement	115	160	180	145	125	125
Nuclear fuel	90	140	100	135	135	75
NSP-Minnesota wind projects	—	35	610	—	—	—
Southwest infrastructure expansion	—	5	70	170	290	385
NSP-Minnesota Black Dog	—	5	50	40	5	—
Other capital expenditures	2,139	1,670	1,710	1,790	1,725	1,715
Total capital expenditures	$ 3,359	$ 2,890	$ 3,195	$ 2,625	$ 2,700	$ 2,685

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, renewable portfolio standards and merger, acquisition and divestiture opportunities.

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. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2014 through 2018 are shown in the table below.



* Cash from operations, net of dividend and pension funding.
** Reflects a combination of short and long-term debt.

During the first half of 2014, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- PSCo may issue approximately $300 million of first mortgage bonds;
- NSP-Minnesota may issue approximately $300 million of first mortgage bonds;
- SPS may issue approximately $150 million of first mortgage bonds; and
- NSP-Wisconsin may 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.

2013 Financing Activity — During 2013, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- PSCo issued $250 million of 2.50 percent first mortgage bonds due March 15, 2023 and $250 million of 3.95 percent first mortgage bonds due March 15, 2043;
- Xcel Energy Inc. issued $450 million of 0.75 percent senior unsecured notes due May 9, 2016;
- NSP-Minnesota issued $400 million of 2.60 percent first mortgage bonds due May 15, 2023; and
- SPS issued $100 million of 4.50 percent first mortgage bonds due Aug. 15, 2041.

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 at-the-market offering program. No shares of common stock have been issued through this program since April 2013. As of Dec. 31, 2013, Xcel Energy Inc. sold 7.7 million shares of common stock with net proceeds of $223 million.

On May 31, 2013, Xcel Energy Inc. redeemed the entire $400 million principal amount of its 7.60 percent junior subordinated notes. Upon redemption, Xcel Energy Inc. recognized $6.3 million of related unamortized debt issuance costs as interest charges.

Note 4. Rates and Regulation

NSP-Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — On Nov. 4, 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 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 overall increase in revenues of approximately $193 million or 6.9 percent in 2014 and an additional $98 million in 2015 or 3.5 percent. The request includes a proposed rate moderation plan for 2014 and 2015. After reflecting interim rate adjustments, the impact of NSP-Minnesota's request on customer bills would result in a 4.6 percent increase in 2014 and an additional 5.6 percent in 2015.

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the theoretical depreciation reserve which the MPUC approved in NSP-Minnesota's last electric rate case 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 its decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello life cycle management (LCM)/extended power uprate (EPU) project costs and our request to amortize amounts associated with the canceled Prairie Island EPU project. NSP-Minnesota plans to file a petition for deferred accounting regarding these Monticello costs in the first quarter of 2014.

The rate request, moderation plan, interim rate adjustments, customer bill impacts and certain impacts on expenses are detailed in the table below:

(Millions of Dollars)	2014	Percentage Increase	2015	Percentage Increase
Pre-moderation deficiency	**$ 274**		**$ 81**	
Moderation change compared to prior year:				
Theoretical depreciation reserve	(81)		53	
DOE settlement proceeds	—		(36)	
Filed rate request	**193**	**6.9%**	**98**	**3.5%**
Interim rate adjustments	(66)		66	
Impact on customer bill	**127**	**4.6%**	**164**	**5.6%**
Potential expense deferral (Monticello/Prairie Island EPU projects)	16		—	
Depreciation expense - reduction/(increase)	81		(46)	
Recognition of DOE settlement proceeds	—		36	
Pre-tax impact on operating income	**$ 224**		**$ 154**	

On Dec. 12, 2013, the MPUC approved interim rates of $127 million as requested, 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 our request to accelerate the theoretical depreciation reserve amortization was a permissible adjustment to our interim rate request even though it differed from the MPUC's 2013 Minnesota rate case order.

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

- Direct Testimony — June 5, 2014
- Rebuttal Testimony — July 7, 2014
- Surrebuttal Testimony — Aug. 4, 2014
- Evidentiary Hearing — Aug. 11-18, 2014
- Reply Brief — Oct. 14, 2014
- Administrative Law Judge (ALJ) Report — Dec. 22, 2014

A final MPUC decision is anticipated in March 2015.

NSP-Minnesota Nuclear Project Prudence Investigation — The MPUC has initiated an investigation to determine whether the costs in excess of those included in the Certificate of Need (CON) for NSP-Minnesota's Monticello LCM/EPU project were prudently incurred. In October 2013, NSP-Minnesota filed a summary 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. The results and any recommendations from the conclusion of this prudence proceeding are expected to be considered by the MPUC in NSP-Minnesota's 2014 Minnesota electric rate case. A final decision is anticipated in the first quarter of 2015.

In December 2013, the NRC granted the EPU license amendment. The complementary Maximum Extended Load Line Limit Analysis Plus fuel license, which is a plant safety analysis allowing for greater operational flexibility, is anticipated to be received during the first half of 2014.

NSP System Resource Plans — In March 2013, the MPUC approved NSP-Minnesota's 2011-2025 Resource Plan and ordered a competitive acquisition process be conducted with the goal of adding approximately 500 megawatts (MW) of generation to the NSP System by 2019. Bid proposals were received in April 2013.

In September 2013, NSP-Minnesota submitted testimony and recommended a self-build, 215 MW natural gas combustion turbine at the Black Dog site and a purchase power agreement (PPA) with either Calpine's Mankato combined cycle natural gas project or Invenergy's Cannon Falls combustion turbine natural gas project. In October 2013, the Minnesota Department of Commerce (DOC) filed testimony and recommended the MPUC approve NSP-Minnesota's proposal.

On Dec. 31, 2013, the ALJ recommended the MPUC select a combination of a 100 MW solar proposal by Geronimo Energy, LLC and capacity credits offered by Great River Energy.

On Jan. 21, 2014, NSP-Minnesota filed exceptions to the ALJ's report which supported our original proposal, reiterated our commitment to meeting the solar mandate and made the following points:

- The ALJ's report focused on meeting a portion of the solar mandate even though the docket was designed to meet our resource need;
- Solar acquisition to meet the solar mandate should be conducted separately to encourage competition among solar developers;
- One or more gas fueled plants should be selected because they are large enough to meet the range of reasonably expected need, are least cost, and comply with environmental regulations; and
- Resource need uncertainty should be addressed through contract options to delay or cancel resources.

The MPUC is expected to make its selection determination in March 2014.

In the first half of 2013, NSP-Minnesota also issued a Request for Proposal (RFP) for cost effective wind generation. In the summer of 2013, NSP-Minnesota filed a petition with the MPUC and the North Dakota Public Service Commission (NDPSC) seeking approval of four wind generation projects. The projects are as follows:

- A 200 MW ownership project for the Pleasant Valley wind farm in Minnesota, which is expected to be operational by October 2015;
- A 150 MW ownership project for the Border Winds wind farm in North Dakota, which is expected to be operational by 2015;
- 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 four wind projects were approved by the MPUC. A NDPSC decision is anticipated in early 2014. The feasibility of the Border Winds and Pleasant Valley projects are also dependent on the finalization of estimated transmission costs, which Midcontinent Independent Transmission System Operator, Inc. is expected to determine in the first half of 2014.

NSP-Minnesota – North Dakota 2013 Electric Rate Case — In December 2012, NSP-Minnesota filed a request with the NDPSC to increase annual retail electric rates approximately $16.9 million, or 9.25 percent. The rate filing was based on a 2013 forecast test year (FTY), a requested ROE of 10.6 percent, an electric rate base of approximately $377.6 million and an equity ratio of 52.56 percent. In January 2013, the NDPSC approved an interim electric increase of $14.7 million, effective Feb. 16, 2013, subject to refund.

In August 2013, NSP-Minnesota filed rebuttal testimony revising the requested increase in retail electric rates to approximately $14.9 million, based on a revised ROE of 10.25 percent and incorporating updated information.

In December 2013, a comprehensive settlement agreement between NSP-Minnesota and NDPSC Staff was filed for approval, proposing resolution to the rate case and resolution of various regulatory proceedings for wind and natural gas generating resources pending before the NDPSC. The settlement agreement provides for a four-year rate plan including a 5.0 percent annual increase in retail revenues in North Dakota, effective Feb. 16, 2013 through Dec. 31, 2015, with no increase in 2016. As filed, the estimated 2013 settlement impact is $11.6 million.

The table below reflects the proposed settlement's impact on 2013 pre-tax operating income.

(Millions of Dollars)	Settlement Impact
Proposed 12 month settlement base rate increase	$ 9.1
Pre-effective period impact (Jan. 1, 2013 - Feb. 15, 2013)	(1.1)
Proposed settlement base rate increase	8.0
Retention of DOE settlement proceeds	3.9
Other, net	(0.3)
Estimated settlement impact on 2013 pre-tax operating income	$ 11.6

Additional settlement terms include:

- An approval of two new rate rider tariff mechanisms to recover transmission and North Dakota renewable costs;
- An authorized ROE of 9.75, 10.0, 10.0 and 10.25 percent in 2013 through 2016, respectively;
- A 50 percent earnings sharing mechanism for amounts earned in excess of the authorized ROEs during the term of the settlement;
- The continued use of a twelve month coincident peak (CP) demand allocator for certain rate base and operating expenses;
- A commitment to develop a generation cost allocation mechanism over the next 18 months that reflects North Dakota energy policy; providing for the exclusion of resources deemed inconsistent with North Dakota energy policy beginning in 2016 (such as certain Minnesota wind and biomass purchase power agreements) and reflecting replacement of those costs based on either system average costs or like resource costs (base load for base load generation, etc.) and recognizing the time needed to address complexity among multiple jurisdictions by providing that a plan for this mechanism be filed by June 2015;
- The commitment to construct up to 400 MW of thermal generation in North Dakota by 2036 subject to least-cost resource planning principles; and
- The retention of DOE settlement proceeds received in 2012, 2013 and expected in 2014.

The NDPSC held a hearing on Jan. 23, 2014 to discuss the details of the proposed settlement agreement. A final NDPSC decision on the case is anticipated in the first quarter of 2014.

NSP-Wisconsin – Wisconsin 2014 Electric and Gas Rate Case — In May 2013, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to increase rates for electric and natural gas service effective Jan. 1, 2014. NSP-Wisconsin requested an overall increase in annual electric rates of $40.0 million, or 6.5 percent, and an increase in natural gas rates of $4.7 million, or 3.8 percent. The electric rate increase included a $4.5 million adjustment related to proceeds from a nuclear settlement agreement with the DOE.

The rate filing was based on a 2014 FTY, an ROE of 10.4 percent, an equity ratio of 52.5 percent, and a forecasted average rate base of approximately $895.3 million for the electric utility and $89.8 million for the natural gas utility.

In October 2013, NSP-Wisconsin filed rebuttal testimony revising the requested electric rate increase to $34.3 million and natural gas rate increase to zero, based on a 10.4 percent ROE and other adjustments.

In December 2013, the PSCW approved an electric rate increase of approximately $19.5 million or 3.1 percent based on a 10.2 percent ROE and an equity ratio of 52.5 percent. The PSCW also approved cost deferrals of $4.1 million for interchange agreement amounts from NSP-Minnesota related to the Monticello EPU project until the MPUC completes its prudence review. The PSCW did not change rates for NSP-Wisconsin's natural gas utility. New electric rates went into effect on Jan. 1, 2014.

PSCo – Colorado 2013 Gas Rate Case — In December 2012, PSCo filed a multi-year request with the Colorado Public Utilities Commission (CPUC) to increase Colorado retail natural gas rates by $48.5 million in 2013 with subsequent step increases of $9.9 million in 2014 and $12.1 million in 2015. The request was based on a 2013 FTY, a 10.5 percent ROE, a rate base of $1.3 billion and an equity ratio of 56 percent. PSCo requested an extension of its Pipeline System Integrity Adjustment (PSIA) rider mechanism to collect the costs associated with its pipeline integrity efforts, including accelerated system renewal projects. PSCo estimated that the PSIA would increase by $26.8 million in 2014 with a subsequent step increase of $24.7 million in 2015 in addition to the proposed changes in base rate revenue. Interim rates, subject to refund, went into effect in August 2013.

In April 2013, several parties filed testimony. PSCo filed rebuttal testimony and revised its requested annual rate increase to $44.8 million for 2013, with subsequent step increases of $9.0 million for 2014 and $10.9 million for 2015, based on an ROE of 10.3 percent. This requested increase includes amounts to be transferred from the PSIA rider mechanism. The deficiency, based on an FTY, was $30.6 million.

In December 2013, the CPUC approved a natural gas base rate increase of approximately $15.8 million, based on an ROE of 9.72 percent, a historic test year (HTY) with an end of year rate base and an equity ratio of 56 percent. As of Dec. 31, 2013, PSCo accrued revenue subject to refund of approximately $20.9 million.

While the CPUC rejected PSCo's request of an FTY and multi-year rate plan, they made clear they supported the benefits that rate certainty brings to customers and PSCo. The CPUC did not reverse the ALJ's failure to approve expansion and acceleration of PSCo's pipeline integrity projects. However, the CPUC discussed the importance of pipeline integrity and safety matters and extended the PSIA recovery mechanism for one year to allow for PSCo to file an application for full consideration of all new projects and acceleration.

The following table summarizes the CPUC decision:

(Millions of Dollars)	**CPUC Decision**
PSCo deficiency based on a FTY	$ 44.8
HTY adjustment	(5.4)
ROE and capital structure adjustments	(8.3)
Revenue adjustments	(1.4)
Other	(0.1)
Recommendation	29.6
Neutralize PSIA - base rate transfer	(13.8)
Incremental base revenue	$ 15.8

Rates and conforming changes made to the PSIA were effective Jan. 1, 2014. On Jan. 13, 2014, PSCo petitioned the CPUC to reverse its decision and approve PSCo's initiatives to replace pipeline installed prior to 1950 and to accelerate previously approved integrity initiatives. PSCo requested that the CPUC expedite a new proceeding to determine approved cost recovery through the PSIA. PSCo requested to increase the incremental base revenue by an additional $1.4 million for updated test year revenues. The CPUC is anticipated to act on this request in February 2014.

PSCo – Colorado 2013 Steam Rate Case — In December 2012, PSCo filed a request to increase Colorado retail steam rates by $1.6 million in 2013 with subsequent step increases of $0.9 million in 2014 and $2.3 million in 2015. The request was based on a 2013 FTY, a 10.5 percent ROE, a rate base of $21 million for steam and an equity ratio of 56 percent.

In October 2013, PSCo, the CPUC Staff, the Office of Consumer Counsel (OCC) and Colorado Energy Consumers filed a comprehensive settlement, which tied the outcome of the steam rate case to key issues to be decided in the natural gas rate case, including ROE and capital structure. The settlement allowed the filed rates to be effective on Jan. 1, 2014, subject to refund, resulting in a minimum 2014 annual rate increase of $1.2 million. The settlement also withdrew the rate relief request for 2015 without prejudice to PSCo seeking prospective rate relief at any time through the filing of a future steam case. In November 2013, the settlement became final. Final rates will be implemented on Feb. 1, 2014.

Colorado 2011 Electric Resource Plan and 2013 All-Source Solicitation — In March 2013, PSCo issued an All-Source RFP for 250 MW by the end of 2018. PSCo also issued a separate wind RFP for PPAs only.

In September 2013, PSCo filed its preferred plan with the CPUC for resources through 2018. The CPUC provided final approval to the plan in December 2013. The approved plan includes the following:

- The addition of 450 MW of wind generation PPAs. This additional wind would bring the installed capacity on the PSCo's system in Colorado to 2,650 MW;
- The addition of 170 MW of utility-scale solar generation PPAs. PSCo currently has about 80 MW of utility-scale solar and 160 MW of customer-sited solar generation;
- The addition of 317 MW of natural gas fired generation PPAs, which would come from existing power plants that previously supplied PSCo, but at reduced prices;
- Accelerated retirement of the 109 MW, coal-fired Unit 4 at the Arapahoe generating station, which occurred at the end of 2013;
- Confirmation of the retirement of the 45 MW, coal-fired Unit 3 at the Arapahoe generating station, which occurred at the end of 2013; and
- The continued operation of Cherokee generating station's Unit 4 as a natural gas facility after 2017.

In addition, PSCo continues to execute on the remaining aspects of CACJA compliance including the construction of a new natural gas fired combined cycle unit at Cherokee generating station and the addition of emissions controls at the Pawnee and Hayden stations. PSCo also expects to retire the Cherokee Unit 3 and Valmont Unit 5 coal-fired power plants by the end of 2015 and 2017, respectively.

Boulder, Colo. Municipalization Exploration — On Jan. 6, 2014, Boulder sent PSCo a Notice of Intent to Acquire (NOIA) for PSCo's transmission, distribution and property assets within an area that includes Boulder and certain areas outside city limits. The NOIA is a legal prerequisite to the filing of an eminent domain proceeding in Colorado courts. However, sending the NOIA does not require Boulder to move forward with a condemnation case.

Boulder's municipalization plan assumes that Boulder will acquire through condemnation PSCo facilities (and customers currently served from these PSCo facilities) that are located outside Boulder's incorporated limits. PSCo petitioned the CPUC for a declaratory ruling that Boulder cannot serve PSCo's customers outside Boulder's city limits without obtaining a certificate of public convenience and necessity from the CPUC. The CPUC declared that it has jurisdiction under Colorado law to determine the utility that will serve customers outside Boulder's city limits, and will determine what facilities need to be constructed to ensure reliable service. The CPUC stated it believes that the cost of all new facilities must be paid by Boulder. The CPUC declared that it should make its determinations prior to any eminent domain actions. On Jan. 15, 2014, Boulder appealed this ruling to Boulder District Court.

If Boulder commences an eminent domain proceeding, PSCo will 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 2014 Electric Rate Case — On Jan. 7, 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 reflects 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, as shown in the following table:

(Millions of Dollars)	SPS Request
Base rate increase	$ 81.5
Resetting TCRF	(12.9)
Credit to customers for gain on sale to Lubbock moved to a rider	(4.9)
Net increase in base revenue	63.7
Fuel clause offsets	(11.0)
Retail customer net bill impact	$ 52.7

The rate filing is based on a 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 reflects an increase in depreciation expense of approximately $16 million.

Texas law allows the PUCT to suspend the proposed increase through July 11, 2014, but parties may negotiate a different effective date, depending on whether the case is settled or fully litigated. SPS has requested interim rates of $32.6 million be effective March 1, 2014. The PUCT typically does not grant interim rates absent a settlement.

Next steps in the procedural schedule are as follows:

- Intervenor testimony — May 22, 2014;
- PUCT Staff testimony — May 29, 2014;
- Cross-rebuttal testimony — June 12, 2014;
- Rebuttal testimony — June 16, 2014; and
- Evidentiary hearing — June 25, 2014.

A PUCT decision and implementation of final rates are anticipated in the third quarter of 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 is based on a 2014 FTY, a requested ROE of 10.65 percent, an electric rate base of $479.8 million and an equity ratio of 53.89 percent. In June 2013, SPS revised its requested rate increase to $43.3 million.

In August 2013, the NMPRC Staff (Staff), the New Mexico Attorney General (NMAG), the Federal Executive Agencies, the Coalition of Clean Affordable Energy, Occidental Permian, Ltd. and New Mexico Gas Company filed testimony.

The following table summarizes certain parties' recommendations from SPS' revised request:

(Millions of Dollars)	Staff Testimony August 2013	NMAG Testimony August 2013
SPS revised request	$ 43.3	$ 43.3
Rate rider for renewable energy costs [(a)]	(14.5)	(8.5)
Present revenues (sales growth and weather)	(4.4)	(6.4)
ROE (9.8 percent and 8.63 percent, respectively)	(3.2)	(8.1)
Capital structure	(1.5)	(1.1)
Employee benefits	(2.8)	(1.8)
Reduced recovery for payroll expense	(0.1)	(0.1)
Gain on sale of transmission assets	—	(1.7)
Fuel clause revenue	6.0	—
Other, net	(5.0)	(6.6)
Recommended rate increase	$ 17.8	$ 9.0
Means of recovery:		
Base revenue	$ 8.8	$ (6.0)
Rider revenue	7.3	13.3
Fuel cost adjustment revenue	1.7	1.7
	$ 17.8	$ 9.0

(a) Adjustments represent recommended deferrals, extended amortizations and moving costs from rider to fuel in base rates.

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. This reflects 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 January 2014, the hearing examiner released her recommended decision. SPS estimates the recommendation reduces the requested rate increase by approximately $6.2 million, resulting in a base revenue increase of $14.7 million. The recommendation proposes an ROE of 9.73 percent, an equity ratio of 53.89 percent, an FTY with certain adjustments and excludes certain employee benefits and other costs. Due to time constraints, the recommended decision did not include a recommendation regarding the requested renewable energy rider revenue increase, but SPS expects the NMPRC to make a decision on the rate rider and related issues in its final order. Parties may now file exceptions to the hearing examiner's recommendation. An NMPRC decision and final rates are expected to be effective in the second quarter of 2014.

Note 5. Sale of Texas Transmission Assets

Sale of Texas Transmission Assets — In March 2013, SPS reached an agreement to sell certain segments of SPS' transmission lines and two related substations to Sharyland. In 2013, SPS received all necessary regulatory approvals for the transaction. On Dec. 30, 2013, SPS received $37.1 million and recognized a pre-tax gain of $13.6 million. The gain is reflected in the consolidated statement of income as a reduction to O&M expenses. Regulatory liabilities were recorded for jurisdictional gain sharing of $7.2 million.

Note 6. SPS FERC Orders

SPS 2004 FERC Complaint Case Orders — In August 2013, the FERC issued an order on rehearing related to a 2004 Complaint case brought by Golden Spread Electric Cooperative, Inc. (Golden Spread), a wholesale cooperative customer, and Public Service Company of New Mexico (PNM) and an Order on Initial Decision in a subsequent 2006 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 3CP rather than a 12CP system.

The pre-tax impact to 2013 earnings from these orders is approximately $36 million. Pending the timing and resolution of this matter, the annual impact to revenues through 2014 could be up to $6 million and decreasing to $4 million on June 1, 2015.

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 in attempt to change all customers to a 3CP allocation method.

Note 7. 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-adjusted retail electric utility sales are projected to increase by approximately 0.5 percent.
- Weather-adjusted retail firm natural gas sales are projected to decline by approximately 0.0 percent to 2.0 percent.
- Capital rider revenue is projected to increase by $50 million to $60 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 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 $50 million to $55 million over 2013 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $0 to $10 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 507 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.

Note 8. 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):

(Thousands of Dollars)	Three Months Ended Dec. 31 2013	Three Months Ended Dec. 31 2012	Twelve Months Ended Dec. 31 2013	Twelve Months Ended Dec. 31 2012
Ongoing earnings	$ 150,055	$ 140,170	$ 968,425	$ 888,285
SPS 2004 FERC complaint case orders	—	—	(20,191)	—
Prescription drug tax benefit	—	—	—	16,944
GAAP earnings	**$ 150,055**	**$ 140,170**	**$ 948,234**	**$ 905,229**

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 6.

Patient Protection and Affordable Care Act — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Xcel Energy expensed approximately $17 million of previously recognized tax benefits relating to the federal subsidies during the first quarter of 2010.

In the third quarter of 2012, Xcel Energy implemented a tax strategy related to the allocation of funding of Xcel Energy's retiree prescription drug plan. This strategy restored a portion of the tax benefit associated with federal subsidies for prescription drug plans that had been accrued since 2004 and was expensed in 2010. As a result, Xcel Energy recognized approximately $17 million of income tax benefit.

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

	Three Months Ended Dec. 31	
	2013	2012
Operating revenues:		
Electric and natural gas	$ 2,710,451	$ 2,531,489
Other	20,371	19,646
Total operating revenues	2,730,822	2,551,135
Net income	$ 150,055	$ 140,170
Weighted average diluted common shares outstanding	498,802	489,136
Components of Earnings per Share — Diluted		
Regulated utility	$ 0.33	$ 0.33
Xcel Energy Inc. and other costs	(0.03)	(0.04)
Ongoing diluted earnings per share	**0.30**	**0.29**
SPS 2004 FERC complaint case orders [(a)]	—	—
Prescription drug tax benefit [(a)]	—	—
GAAP diluted earnings per share	**$ 0.30**	**$ 0.29**

	Twelve Months Ended Dec. 31	
	2013	2012
Operating revenues:		
Electric and natural gas	$ 10,838,724	$ 10,054,670
Other	76,198	73,553
Total operating revenues	10,914,922	10,128,223
Net income	$ 948,234	$ 905,229
Weighted average diluted common shares outstanding	496,532	488,434
Components of Earnings per Share — Diluted		
Regulated utility	$ 2.09	$ 1.96
Xcel Energy Inc. and other costs	(0.14)	(0.14)
Ongoing diluted earnings per share	**1.95**	**1.82**
SPS 2004 FERC complaint case orders [(a)]	(0.04)	—
Prescription drug tax benefit [(a)]	—	0.03
GAAP diluted earnings per share	**$ 1.91**	**$ 1.85**
Book value per share	$ 19.21	$ 18.19

(a) See Note 8.