414 Nicollet Mall
Minneapolis, MN 55401

Oct. 24, 2013

XCEL ENERGY
THIRD QUARTER 2013 EARNINGS REPORT

- Ongoing 2013 third quarter earnings per share were $0.77 compared with $0.78 per share in 2012.
- GAAP (generally accepted accounting principles) 2013 third quarter earnings per share were $0.73 compared with $0.81 per share in 2012.
- Xcel Energy expects 2013 ongoing earnings to be in the upper half of the guidance range of $1.85 to $1.95 per share.
- Xcel Energy expects 2013 GAAP earnings to be within the guidance range of $1.85 to $1.95 per share.
- Xcel Energy initiates 2014 ongoing earnings guidance of $1.90 to $2.05 per share.
- Xcel Energy updates long-term annual dividend and earnings per share growth rate objectives to 4 to 6 percent.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2013 third quarter GAAP earnings of $365 million, or $0.73 per share, compared with 2012 GAAP earnings of $398 million, or $0.81 per share.

Ongoing earnings, which exclude adjustments for certain items, were $0.77 per share for the third quarter of 2013 compared with $0.78 per share in 2012. Third quarter 2013 ongoing earnings declined as a result of cooler weather and higher operating and maintenance expenses. While third quarter 2013 weather was warmer than normal, it was cooler than the third quarter of 2012. These factors were partially offset by rate increases in various states.

Third quarter 2013 GAAP earnings include a $0.04 per share charge for a potential SPS customer refund based on FERC orders issued in August 2013 related to a 2004 complaint regarding the allocation of system average fuel costs and base rates. Third quarter 2012 GAAP earnings reflect the $0.03 per share positive impact for a tax benefit associated with federal subsidies for prescription drug plans.

“While the final electric rate increase in Minnesota was less than expected, the combination of favorable weather and effective management actions position us to deliver 2013 ongoing earnings in the upper half of our guidance range,” stated Ben Fowke, Chairman, President and Chief Executive Officer. “In addition, we have updated our financial objectives. We are increasing our dividend growth rate objective to 4 to 6 percent to align with our annual earnings per share growth rate of 4 to 6 percent that should allow us to provide an attractive total return for our shareholders for years to come. We are also introducing our 2014 ongoing earnings guidance of $1.90 to $2.05 per share.”

“Finally, we faced another operational challenge with the severe flooding in Colorado, a challenge we again successfully met. Repairing miles of natural gas pipe and thousands of gas and electric meters is substantially complete; again clearly demonstrating that we are well prepared for such events.” said Fowke.

Earnings Adjusted for Certain Items (Ongoing Earnings)

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	**2013**	**2012**	**2013**	**2012**
Ongoing [(a)] diluted earnings per share	**$ 0.77**	**$ 0.78**	**$ 1.65**	**$ 1.54**
SPS 2004 FERC complaint case orders [(b)]	(0.04)	—	(0.04)	—
Prescription drug tax benefit [(b)]	—	0.03	—	0.03
GAAP diluted earnings per share	**$ 0.73**	**$ 0.81**	**$ 1.61**	**$ 1.57**

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

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

US Dial-In:	(877) 941-0843
International Dial-In:	(480) 629-9866
Conference ID:	4643034

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. CDT on Oct. 24 through 11:59 p.m. CDT on Oct. 25.

Replay Numbers	
US Dial-In:	(800) 406-7325
International Dial-In:	(303) 590-3030
Access Code:	4643034#

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 2013 and 2014 full year 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 and June 30, 2013.

For more information, contact:

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

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

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2013	2012	2013	2012
Operating revenues				
Electric	$ 2,599,925	$ 2,532,709	$ 6,911,998	$ 6,506,320
Natural gas	205,358	174,513	1,216,275	1,016,861
Other	17,055	17,119	55,827	53,907
Total operating revenues	2,822,338	2,724,341	8,184,100	7,577,088
Operating expenses				
Electric fuel and purchased power	1,097,944	1,006,830	3,034,031	2,725,183
Cost of natural gas sold and transported	74,847	49,739	702,987	557,444
Cost of sales — other	7,540	7,251	23,832	20,499
Operating and maintenance expenses	575,305	531,480	1,667,093	1,576,178
Conservation and demand side management program expenses	67,811	68,920	192,288	191,242
Depreciation and amortization	228,491	239,051	721,131	694,364
Taxes (other than income taxes)	105,287	100,636	320,765	305,892
Total operating expenses	2,157,225	2,003,907	6,662,127	6,070,802
Operating income	665,113	720,434	1,521,973	1,506,286
Other (expense) income, net	(404)	488	3,931	4,953
Equity earnings of unconsolidated subsidiaries	7,273	7,490	22,379	22,150
Allowance for funds used during construction — equity	21,284	15,860	63,147	44,504
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,020, $6,010, $24,058, and $18,126, respectively	144,758	153,719	431,199	457,470
Allowance for funds used during construction — debt	(9,377)	(10,439)	(28,451)	(24,729)
Total interest charges and financing costs	135,381	143,280	402,748	432,741
Income from continuing operations before income taxes	557,885	600,992	1,208,682	1,145,152
Income taxes	193,349	202,845	410,676	380,161
Income from continuing operations	364,536	398,147	798,006	764,991
Income (loss) from discontinued operations, net of tax	216	(41)	173	68
Net income	$ 364,752	$ 398,106	$ 798,179	$ 765,059
Weighted average common shares outstanding:				
Basic	498,149	488,084	495,256	487,722
Diluted	498,641	488,578	495,767	488,198
Earnings per average common share:				
Basic	$ 0.73	$ 0.82	$ 1.61	$ 1.57
Diluted	0.73	0.81	1.61	1.57
Cash dividends declared per common share	$ 0.28	$ 0.27	$ 0.83	$ 0.80

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) 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. EPS by subsidiary is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of earnings results. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to our consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

Note 1. Earnings Per Share Summary

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	**2013**	**2012**	**2013**	**2012**
Public Service Company of Colorado (PSCo)	$ 0.33	$ 0.36	$ 0.77	$ 0.75
NSP-Minnesota	0.31	0.28	0.67	0.57
Southwestern Public Service Company (SPS)	0.11	0.12	0.19	0.20
NSP-Wisconsin	0.05	0.04	0.11	0.09
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.03
Regulated utility — continuing operations [(a)]	0.81	0.81	1.77	1.64
Xcel Energy Inc. and other costs	(0.04)	(0.03)	(0.12)	(0.10)
Ongoing [(a)] diluted earnings per share	0.77	0.78	1.65	1.54
SPS 2004 FERC complaint case orders [(b)]	(0.04)	—	(0.04)	—
Prescription drug tax benefit [(b)]	—	0.03	—	0.03
GAAP diluted earnings per share	**$ 0.73**	**$ 0.81**	**$ 1.61**	**$ 1.57**

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

PSCo — PSCo's ongoing earnings decreased $0.03 per share for the third quarter of 2013 and increased $0.02 per share for the nine months ended Sept. 30, 2013. Third quarter earnings declined as a result of lower electric margins and higher operating and maintenance (O&M) expenses. Electric margins were impacted by cooler weather compared to prior year and accruals for potential customer refunds associated with the 2013 earnings test. These factors were partially offset by lower interest charges.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.03 per share for the third quarter of 2013 and $0.10 per share for the nine months ended Sept. 30, 2013. Earnings were positively impacted by electric rate increases in Minnesota, South Dakota and North Dakota interim rates, subject to refund, and lower interest charges. These were partially offset by higher O&M expenses and property taxes.

SPS — SPS' ongoing earnings decreased $0.01 per share for the third quarter of 2013 and for the nine months ended Sept. 30, 2013. Higher O&M expenses, depreciation, interest charges and the impact of cooler summer weather were partially offset by electric rate increases in Texas.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.01 per share for the third quarter of 2013 and $0.02 per share for the nine months ended Sept. 30, 2013. Higher earnings from electric and natural gas rates were partially offset by higher depreciation, O&M expenses and cooler summer weather.

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 Sept. 30	Nine Months Ended Sept. 30
2012 GAAP diluted earnings per share	**$ 0.81**	**$ 1.57**
Prescription drug tax benefit [b]	(0.03)	(0.03)
2012 ongoing [a] diluted earnings per share	**0.78**	**1.54**
Components of change — 2013 vs. 2012		
Higher electric margins (excludes impact of SPS 2004 FERC complaint case orders) [b]	—	0.15
Higher natural gas margins	0.01	0.07
Lower interest charges (excludes impact of SPS 2004 FERC complaint case orders) [b]	0.02	0.04
Higher AFUDC — equity	0.01	0.04
Lower effective tax rate	0.02	0.02
Higher O&M expenses	(0.05)	(0.11)
Lower (higher) depreciation and amortization	0.01	(0.03)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.02)	(0.03)
Higher taxes (other than income taxes)	(0.01)	(0.02)
Other, net	—	(0.02)
2013 ongoing [a] diluted earnings per share	**0.77**	**1.65**
SPS 2004 FERC complaint case orders [b]	(0.04)	(0.04)
2013 GAAP diluted earnings per share	**$ 0.73**	**$ 1.61**

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

Note 2. Regulated Utility Results — Continuing Operations

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 Sept. 30			Nine Months Ended Sept. 30		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
HDD	(44.6)%	(23.3)%	(30.7)%	5.4%	(21.4)%	33.4%
CDD	15.6	33.1	(11.4)	25.3	46.9	(13.7)
THI	28.0	34.3	(2.1)	23.0	37.2	(9.7)

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

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
Retail electric	$ 0.048	$ 0.076	$ (0.028)	$ 0.079	$ 0.083	$ (0.004)
Firm natural gas	(0.001)	(0.001)	—	0.015	(0.030)	0.045
Total	$ 0.047	$ 0.075	$ (0.028)	$ 0.094	$ 0.053	$ 0.041

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

	Three Months Ended Sept. 30	
	Actual	Weather Normalized
Electric residential	(2.4)%	0.6%
Electric commercial and industrial	(0.5)	0.1
Total retail electric sales	(1.1)	0.3
Firm natural gas sales [(a)]	4.9	5.2

	Nine Months Ended Sept. 30		Nine Months Ended Sept. 30 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	2.7%	0.1%	3.3%	0.7%
Electric commercial and industrial	(0.4)	(0.6)	0.1	(0.1)
Total retail electric sales	0.4	(0.4)	0.9	0.1
Firm natural gas sales [(a)]	31.3	3.7	32.4	4.6

(a) As normal weather conditions are typically defined as a 30-year average of actual historical weather conditions, significant weather variations in periods of low demand may result in large percentage changes on small volumes.

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 Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2013	2012	2013	2012
Electric revenues	$ 2,600	$ 2,533	$ 6,912	$ 6,506
Electric fuel and purchased power	(1,098)	(1,007)	(3,034)	(2,725)
Electric margin	$ 1,502	$ 1,526	$ 3,878	$ 3,781

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

(Millions of Dollars)	Three Months Ended Sept. 30 2013 vs. 2012	Nine Months Ended Sept. 30 2013 vs. 2012
Retail rate increases [(a)]	$ 46	$ 177
Transmission revenue, net of costs	9	29
Non-fuel riders	7	10
Conservation and demand side management (DSM) program incentives	(17)	(26)
PSCo earnings test refund obligation	(11)	(20)
Firm wholesale	(7)	(20)
SPS 2004 FERC complaint case orders [(b)]	(5)	(5)
Estimated impact of weather	(20)	(1)
Other, net	—	(21)
Total increase in ongoing electric margin	2	123
SPS 2004 FERC complaint case orders [(b)]	(26)	(26)
Total (decrease) increase in GAAP electric margin	$ (24)	$ 97

(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 $69 million for the third quarter of 2013 and $116 million for the nine months ended Sept. 30, 2013 based on the final rate order received for the 2013 electric rate case. In addition, revenues and expenses were reduced by approximately $30 million, primarily related to depreciation expense of $24 million and O&M expenses of $6 million in the third quarter of 2013 due to the order. See Note 4.

(b) As a result of two orders issued by the Federal Energy Regulatory Commission (FERC), a pretax charge of approximately $35 million ($31 million in electric revenues, of which $5 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in the third quarter of 2013. See Note 5.

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:

(Millions of Dollars)	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2013	2012	2013	2012
Natural gas revenues	$ 205	$ 175	$ 1,216	$ 1,017
Cost of natural gas sold and transported	(75)	(50)	(703)	(557)
Natural gas margin	$ 130	$ 125	$ 513	$ 460

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

(Millions of Dollars)	Three Months Ended Sept. 30 2013 vs. 2012	Nine Months Ended Sept. 30 2013 vs. 2012
Estimated impact of weather	$ —	$ 34
Retail rate increases (Colorado interim and Wisconsin)	7	8
Retail sales growth	1	7
Conservation and DSM program revenues (offset by expenses)	(1)	4
Other, net	(2)	—
Total increase in natural gas margin	$ 5	$ 53

O&M Expenses — O&M expenses increased $43.8 million, or 8.2 percent, for the third quarter of 2013 and $90.9 million, or 5.8 percent, for the nine months ended Sept. 30, 2013 compared with the same periods in 2012. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	Three Months Ended Sept. 30 2013 vs. 2012	Nine Months Ended Sept. 30 2013 vs. 2012
Electric and gas distribution expenses	$ 15	$ 32
Nuclear plant operations and amortization	13	28
Transmission costs	2	11
Employee benefits	5	4
Other, net	9	16
Total increase in O&M expenses	$ 44	$ 91

- 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 decreased $10.6 million, or 4.4 percent, for the third quarter of 2013 and increased $26.8 million, or 3.9 percent, for the nine months ended Sept. 30, 2013 compared with the same periods in 2012. NSP-Minnesota reduced depreciation expense by $24 million in the third quarter of 2013 to reflect the final rate order received for the 2013 Minnesota electric rate case. This reduction was offset by increased depreciation related to normal system expansion.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $4.7 million, or 4.6 percent, for the third quarter of 2013 and $14.9 million, or 4.9 percent, for the nine months ended Sept. 30, 2013 compared with the same periods in 2012. The increases are due to higher property taxes primarily in Minnesota, Colorado and Texas.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased $4.4 million for the third quarter of 2013 and $22.4 million for the nine months ended Sept. 30, 2013 compared with the same periods in 2012. The increases are primarily due to construction related to the Clean Air Clean Jobs Act (CACJA), the expansion of transmission facilities and other capital expenditures.

Interest Charges — Interest charges decreased $9.0 million, or 5.8 percent, for the third quarter of 2013 and $26.3 million, or 5.7 percent, for the nine months ended Sept. 30, 2013 compared with the same periods in 2012. The decreases are primarily due to refinancings at lower interest rates. This is partially offset by higher long-term debt levels, $4 million of interest associated with the customer refund at SPS based on the recent FERC orders and $3 million of interest associated with customer refunds in Minnesota based on the final rate order received for the 2013 Minnesota electric rate case. Also included for the nine months ended Sept. 30, 2013 was 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 for continuing operations decreased $9.5 million for the third quarter of 2013 compared with the same period in 2012. The decrease in income tax expense was primarily due to lower pretax earnings. The effective tax rate (ETR) for continuing operations was 34.7 percent for the third quarter of 2013 compared with 33.8 percent for the same period in 2012. The lower ETR for 2012 was primarily due to a one time tax benefit related to the restoration of a portion of the tax benefit written off in 2010 associated with federal subsidies for prescription drug plans. The ETR would have been 36.6 percent for the third quarter of 2012 without this tax benefit.

Income tax expense for continuing operations increased $30.5 million for the first nine months of 2013 compared with the same period in 2012. The increase in income tax expense was primarily due to higher pretax earnings. The ETR for continuing operations was 34.0 percent for the nine months ended Sept. 30, 2013 compared with 33.2 percent for the same period in 2012. The ETRs for 2013 reflect the benefits of research and experimentation credits, increased permanent plant-related adjustments and a 2013 carryback item. The lower ETR for the nine months ended Sept. 30, 2012 reflects a one time adjustment for a tax benefit associated with a carryback and a tax benefit related to the restoration of a portion of the tax benefit written off in 2010 associated with federal subsidies for prescription drug plans. As a result, Xcel Energy recognized discrete tax benefits of approximately $14.9 million for the carryback and $17 million for the tax benefit associated with the federal subsidies. The ETR would have been 36.0 percent for the nine months ended Sept. 30, 2012 without these tax benefits.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	Sept. 30, 2013	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.3	1%
Short-term debt	0.3	1
Long-term debt	10.9	52
Total debt	11.5	54
Common equity	9.5	46
Total capitalization	$ 21.0	100%

Credit Facilities — As of Oct. 22, 2013, 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	$ 314.0	$ 486.0	$ 0.2	$ 486.2
PSCo	700.0	6.8	693.2	105.5	798.7
NSP-Minnesota	500.0	76.9	423.1	0.1	423.2
SPS	300.0	50.0	250.0	0.2	250.2
NSP-Wisconsin	150.0	45.0	105.0	48.6	153.6
Total	$ 2,450.0	$ 492.7	$ 1,957.3	$ 154.6	$ 2,111.9

(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).

As of Oct. 22, 2013, 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.

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

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 were issued through this program during the third quarter of 2013. As of Sept. 30, 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.

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

Note 4. Rates and Regulation

***NSP-Minnesota – Minnesota 2014 Multi-Year Electric Rate Case* —** In November 2013, NSP-Minnesota expects to file a multi-year rate plan for its Minnesota retail electric jurisdiction. The case will be based on a 2014 forecast test year (FTY) and will include a request for incremental rate recovery for certain capital related costs in 2015. The case is driven by substantial investment in our system – including the replacement of the steam generator at Prairie Island; the life extension at our nuclear plants, the return to service of our Sherco Unit 3 and additional owned wind generation. The rate case also will reflect higher property taxes and other general business costs. Interim rates, subject to refund, are expected to take effect in January 2014. NSP-Minnesota also anticipates introducing a mitigation plan, as part of the rate case, to lessen the impact on the customer bill. NSP-Minnesota's mitigation plan could include further accelerating a theoretical depreciation reserve and/or utilizing expected Department of Energy refunds in excess of amounts needed to fund its decommissioning expense.

NSP-Minnesota – Minnesota 2013 Electric Rate Case — In November 2012, NSP-Minnesota filed a request with the Minnesota Public Utilities Commission (MPUC) for an increase in annual revenues of approximately $285 million, or 10.7 percent. The rate filing was based on a 2013 forecast test year, a requested return on equity (ROE) of 10.6 percent, an average electric rate base of approximately $6.3 billion and an equity ratio of 52.56 percent. In January 2013, interim rates of approximately $251 million became effective, subject to refund.

NSP-Minnesota subsequently revised the requested annual revenue increase to approximately $209 million, or 7.8 percent, based on an ROE of 10.6 percent, a rate base of approximately $6.3 billion an equity ratio of 52.56 percent. The revenue requirement reflected a requested deficiency of $259 million combined with $50 million of rate mitigation through deferral mechanisms.

On Sept. 3, 2013, the MPUC issued an order approving a rate increase of approximately $103 million, or 3.8 percent, based on a 9.83 percent ROE and 52.56 percent equity ratio. In addition, the MPUC authorized approximately $20 million in deferrals, as well as a $24 million reduction in revenue and depreciation expense.

The table below reconciles NSP-Minnesota's original request to the final MPUC order:

(Millions of Dollars)	NSP-Minnesota Request	Administrative Law Judge (ALJ) Recommendation	MPUC Order
NSP-Minnesota original request	$ 285	$ 285	$ 285
ROE	—	(43)	(43)
Sherco Unit 3	(35)	(38)	(34)
Reduced recovery for nuclear plants	(11)	(14)	(15)
Incentive compensation	(3)	(4)	(4)
Sales forecast	(1)	(26)	(26)
Pension	(10)	(13)	(13)
Employee benefits	(4)	(6)	(6)
Black Dog remediation	(5)	(5)	(5)
Estimated impact of the theoretical depreciation reserve	—	—	(24)
NSP-Wisconsin wholesale allocation	(7)	(7)	(7)
Other, net	—	(2)	(5)
Recommended rate increase	209	127	103
Estimated impact of cost deferrals	50	34	20
Estimated impact of the theoretical depreciation reserve	—	—	24
Impact on pre-tax income	$ 259	$ 161	$ 147

NSP-Minnesota filed its final rate implementation and interim rate refund compliance filing on Sept. 19, 2013, requesting final rates be implemented Dec. 1, 2013, with interim rate refunds of approximately $132.2 million, including interest, to begin by January 2014. The Office of the Attorney General requested the MPUC to reconsider its Sept. 3, 2013 order with respect to the calculation of AFUDC. NSP-Minnesota has filed a response opposing the motion. Both items are pending MPUC action.

In the third quarter of 2013, NSP-Minnesota increased the reserve for revenue subject to refund by $30 million, and also recorded a reduction to depreciation expense and other operating expenses in the same amount, to implement the cost deferral and depreciation requirements of the final MPUC order. Adjustments to the reserve in the third quarter of 2013 related to revenue recognized in the first and second quarters of 2013 were not material.

NSP-Minnesota Nuclear Project Prudence Investigation — In the NSP-Minnesota 2013 Minnesota electric rate case final order, the MPUC initiated an investigation to determine whether the costs in excess of those included in the certificate of need for NSP-Minnesota's Monticello life cycle management (LCM)/extended power uprate (EPU) project were prudently incurred. In October 2013, NSP-Minnesota filed a summary report and witness testimony to further support the change in 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. In September 2013, the Advisory Committee to the NRC on Reactor Safety recommended approval of the EPU license. The EPU license is expected to be granted by the end of 2013 and the complementary MELLA Plus fuel license is anticipated to be received in March 2014. NSP-Minnesota has provided information that the cost deviation is in line with similar upgrade projects undertaken 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.

NSP-Minnesota – North Dakota 2013 Electric Rate Case — In December 2012, NSP-Minnesota filed a request with the North Dakota Public Service Commission (NDPSC) to increase annual retail electric rates approximately $16.9 million, or 9.25 percent. The rate filing is based on a 2013 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 June 2013, NSP-Minnesota revised its rate increase to $16 million, reflecting updated information.

On Aug. 12, 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 the updated information from June 2013.

On Aug. 22, 2013, NDPSC Staff filed supplemental testimony revising their recommendation by removing a positive adjustment for federal taxes and adjusting depreciation to reflect longer asset lives. In total, the NDPSC Staff's filed position was modified to a $10 million rate reduction. The recommendation reflects a 9.0 percent ROE.

Primary revenue requirement adjustments include:

(Millions of Dollars)	**NSP-Minnesota Rebuttal Testimony**	**NDPSC Position as Supplemented**
NSP-Minnesota revised request	$ 16.0	$ 16.0
Use of a one month coincident peak demand allocator for certain rate base and operation expenses	—	(20.4)
ROE	(1.2)	(5.2)
Incentive compensation	—	(0.8)
Adjustment for various O&M expenses	—	(0.7)
Modified cost of capital and increased capital structure to 53.42 percent	0.1	1.3
Depreciation/remaining life study	—	(1.1)
Other, net	—	0.9
Recommended rate increase (decrease)	$ 14.9	$ (10.0)

Evidentiary hearings were conducted in late August 2013. A final NDPSC decision on the case is anticipated in the fourth quarter of 2013 or the first quarter of 2014.

NSP-Wisconsin – Wisconsin 2014 Electric and Gas Rate Case — On May 31, 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 rate filing is based on a 2014 FTY, an ROE of 10.4 percent, an equity ratio of 52.5 percent and a forecasted average net investment rate base of approximately $895.3 million for the electric utility and $89.8 million for the natural gas utility.

On Oct. 4, 2013, the PSCW Staff filed their direct testimony and recommended an electric rate increase of $23.8 million, or 3.8 percent, and a natural gas rate decrease of $1.1 million, or 0.9 percent. PSCW Staff's recommendations were based on a 10.2 percent ROE and a 52.5 percent equity ratio.

The most significant adjustments proposed by the PSCW Staff are shown in the table below:

(Millions of Dollars)	Electric Staff Testimony October 2013	Natural Gas Staff Testimony October 2013
Rate request	$ 40.0	$ 4.7
Electric fuel and purchased power	(5.1)	—
Sales forecast	(4.8)	—
Incentive compensation and merit pay	(3.0)	(0.6)
ROE	(1.6)	(0.2)
Conservation funding transfer	0.7	(0.7)
Depreciation expense	(0.7)	(1.3)
Ashland site amortization expense	—	(2.3)
Other, net	(1.7)	(0.7)
Recommended rate increase (decrease)	$ 23.8	$ (1.1)

The majority of the adjustment to electric fuel and purchased power is the result of the PSCW Staff's proposal to discontinue using the New York Mercantile Exchange (NYMEX) futures prices as a basis for setting the fuel price forecast and instead using a discounted percentage of the NYMEX futures prices. PSCW Staff's sales forecast adjustment is based on the assumption that the strong sales growth trend from 2010 through 2012, primarily in the large commercial/industrial sector, will continue through 2013 and 2014, while NSP-Wisconsin's forecast shows moderating growth.

On Oct. 18, 2013, NSP-Wisconsin filed rebuttal testimony, revising the requested electric rate increase to $34 million and natural gas rate increase to zero, based on a 10.4 percent ROE and other adjustments.

Next steps in the procedural schedule are as follows:

- Surrebuttal testimony - Oct. 28, 2013;
- Hearing - Oct. 30, 2013;
- Initial brief - Nov. 13, 2013; and
- Reply brief - Nov. 20, 2013.

A PSCW decision is anticipated in December 2013, with final rates going into effect in January 2014.

NSP-Minnesota – Minnesota Resource Plan — 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 to the MPUC and recommended a self-build, 215 MW natural gas combustion turbine at the Black Dog site and either Calpine's Mankato combined cycle natural gas project or Invenergy's Cannon Falls combustion turbine natural gas project. The competitive acquisition schedule is expected to be as follows:

- Hearings are scheduled for Oct. 21 - 25, 2013;
- ALJ report due Dec. 31, 2013; and
- A final MPUC decision in the first quarter of 2014.

In the first half of 2013, NSP-Minnesota also issued a Request for Proposal (RFP) for wind generation, to the extent that cost effective opportunities can be identified. In addition, NSP-Minnesota filed a petition with the MPUC and the NDPSC seeking approval of four wind generation projects. The potential 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. The feasibility of the Border Winds project is dependent on transmission costs which will be determined by Midcontinent Independent System Operators;
- A 200 MW purchased power agreement (PPA) with Geronimo Energy for the Odell wind farm in Minnesota; and
- A 200 MW PPA with Geronimo Energy for the Courtenay wind farm in North Dakota.

On Oct. 17, 2013, the four projects were approved by the MPUC. A NDPSC decision is anticipated by the end of 2013.

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 is 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 is requesting 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 estimates that the PSIA will 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. In conjunction with the multi-year base rate step increases, PSCo is proposing a stay-out provision and an earnings test through the end of 2015 with a commitment to file a rate case to implement revised rates on Jan. 1, 2016. Interim rates, subject to refund, went into effect in August 2013.

In April 2013, four parties filed answer testimony in the natural gas case. The CPUC Staff and Office of Consumer Counsel (OCC) recommended changes to the level of integrity management costs moved from the PSIA rider to base rates. PSCo's 2013 deficiency based on a FTY net of PSIA changes was $45 million for 2013 and the revenue deficiency was $28.3 million based on a historic test year (HTY).

The CPUC Staff recommended a rate reduction of $14.4 million, based on a HTY, an ROE of 9 percent and an equity ratio of 52 percent and other adjustments. The OCC recommended a rate increase of $0.5 million based on a HTY, an ROE of 9 percent and equity ratio of 51.03 percent and other adjustments. While the OCC did not recommend that the CPUC set rates using a FTY, they did calculate a revenue deficiency of $12.4 million for 2013. No other intervenor made ROE recommendations or specific recommendations regarding the revenue deficiency. The major adjustments to the test year proposed by the CPUC Staff and OCC are presented below.

(Millions of Dollars)	CPUC Staff	OCC
PSCo deficiency based on a HTY	$ 28.3	$ 28.3
ROE and capital structure adjustments	(20.8)	(20.0)
Move to a 13 month average from year end rate base	(5.7)	(3.2)
Remove pension asset	(5.9)	—
Remove incentive compensation	(3.5)	(0.2)
Challenge known and measurable	—	(9.0)
Eliminate depreciation annualization	—	(1.8)
Revenue adjustments	(4.1)	(1.4)
Resulting tax impacts	1.5	4.7
Other adjustments	(4.2)	3.1
Recommendation	$ (14.4)	$ 0.5

On April 26, 2013, the CPUC Staff filed supplemental testimony recommending an additional net disallowance of $1.6 million for adjustments and corrections.

In April 2013, 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. PSCo agreed to recover approximately $3.5 million of revenue requirement in the PSIA, rather than through base rates and accepted the CPUC Staff's recommendation to use deferred accounting to accommodate property tax increases.

On Oct. 22, 2013, the Colorado ALJ issued her recommendation. As part of this decision, she recommended the prepaid pension asset remain in rate base and approved certain incentive costs along with the proposed property tax adjustment. Her recommendation also included the use of a HTY, an ROE of 9.72 percent, an equity ratio of 56 percent and the averaging of rate base. As the issued report does not include a total recommended revenue requirement, PSCo is currently in the process of determining the collective impact of the recommended decision. Exceptions and corresponding responses are due to be filed in November 2013 and a CPUC decision is expected in December 2013.

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 is 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 OCC and Colorado Energy Consumers representing the Buildings Owners Management Association filed a comprehensive settlement which ties the outcome of the steam rate case to key issues to be decided in the natural gas rate case, including ROE and capital structure and allows the filed rates to be effective on Jan. 1, 2014, subject to refund for 60 days, resulting in a minimum 2014 annual rate increase of $1.2 million. The settlement withdraws the rate relief request for 2015 pending the outcome of the certificate of public convenience and necessity proceeding for the construction of the Sun Valley Steam Center. A decision on the settlement is expected at the end of 2013.

Colorado 2011 Electric Resource Plan (ERP) and 2013 All-Source Solicitation — In January 2013, the CPUC approved with modifications the 2011 ERP. 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, which included the following:

- The addition of 450 MW of Colorado 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 Colorado power plants that previously supplied PSCo, but at reduced prices.
- PSCo also examined whether to continue operating two older company-owned power plants or to replace them with new generation resources. PSCo recommended:
    - The permanent closure of the 109 MW, coal-fired Unit 4 at the Arapahoe Generating Station in Denver at the end of 2013;
    - The permanent closure of the 45 MW, coal-fired Unit 3 at the Arapahoe Generating Station in Denver at the end of 2013; and
    - The continued operation of Cherokee Generating Station's Unit 4 in Denver as a natural gas facility after 2017 (the plant fuel source will be switched to natural gas from coal by the end of 2017 as part of the CACJA Plan).

In October 2013, the CPUC approved the proposed wind PPAs, citing the significant benefit to customers of acquiring these renewable resources. The CPUC will consider the remaining recommendations later this fall with a decision expected before the end of 2013.

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, a jurisdictional electric rate base of $479.8 million and an equity ratio of 53.89 percent. On June 19, 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.

On Sept. 9, 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.

The hearings on the merits of the case concluded in September 2013. Next steps in the procedural schedule are expected to be as follows:

- A recommended decision is anticipated from the hearing examiner in November 2013;
- An NMPRC decision is anticipated in the first quarter of 2014; and
- Final rates are expected to be effective in the first quarter of 2014.

Note 5. SPS FERC Orders

SPS 2004 FERC Complaint Case Orders — In August 2013, the FERC issued an order on rehearing and clarification related to a 2004 Complaint case brought by 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; the first was the appropriateness of the allocations of system average fuel costs and the second was a base rate complaint, including the appropriate demand-related cost allocator.

The first issue related to PNM's claim regarding inappropriate allocation of fuel costs. The FERC clarified its initial order and granted SPS' request for clarification that PNM was not entitled to refunds based on the FERC's April 2008 Order in the Complaint case. The FERC determined that refunds should apply only to firm requirements customers and not PNM's contractual load.

The second issue related to the use of a 12 coincident peak (CP) vs. 3CP demand allocator. This issue first arose in the base rate revenue requirements portion of Golden Spread's 2004 Complaint as well as SPS' 2006 rate case. In December 2007, SPS reached a settlement of all fuel issues with Golden Spread, and entered a formula rate agreement for its production costs. That agreement indicated that all issues from the complaint period were resolved and that all base rate issues from the 2006 rate case were resolved other than the 12CP vs. 3CP issue and the formula rate tariff allows this issue to be resolved.

In April 2008, the FERC issued an order resolving the remaining rate issues and found in favor of SPS on the disputed rate issue, concluding that SPS was a 12CP system. Golden Spread asked for rehearing of this issue in May of 2008. Also in May 2008, in a subsequent SPS rate case involving all requirements customers (other than Golden Spread), the FERC granted the motion of the full requirements customers and SPS reaffirming that SPS was a 12CP system. As a result of these FERC actions, SPS considered the issued to be resolved and the risk of loss to be remote.

In the orders issued in August 2013, the FERC reversed itself, stating that it erred in its initial analysis and determined that the SPS system was a 3CP rather than a 12CP system. As a result, SPS estimates that the combination of the order and the December 2007 settlement creates a refund liability of approximately $42 million including interest. This would be partially offset by a reserve that had been established for the PNM decision and the amounts for which the New Mexico Cooperatives had agreed to refund in the event of this outcome. The pre-tax impact to 2013 earnings from these orders is approximately $35 million, which was recorded in the third quarter of 2013. 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 in reversing the 2008 ruling 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 6. Xcel Energy Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy Earnings Guidance — Xcel Energy's 2013 ongoing earnings will be in the upper half of the guidance range of $1.85 to $1.95 per share. Xcel Energy anticipates that 2013 GAAP earnings will be within the guidance range of $1.85 to $1.95 per share. Key assumptions related to 2013 earnings are detailed below:

- Constructive outcomes in all remaining 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 0.0 percent to 0.5 percent.
- Weather-adjusted retail firm natural gas sales are projected to increase by approximately 2 percent.
- O&M expenses are projected to increase approximately 4 percent to 5 percent over 2012 levels.
- Depreciation expense is projected to increase $50 million to $55 million over 2012 levels, reflecting the decision in the 2013 Minnesota electric rate case on the theoretical depreciation reserve.
- Property taxes are projected to increase approximately $15 million to $20 million over 2012 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $30 million to $40 million from 2012 levels.
- AFUDC — equity is projected to increase approximately $20 million to $25 million over 2012 levels.
- The ETR is projected to be approximately 33 percent to 35 percent.
- Average common stock and equivalents are projected to be approximately 497 million shares.

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, including the implementation of interim rates consistent with historical precedent.
- Normal weather patterns are experienced for 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 $45 million to $50 million over 2013 projected levels.
- O&M expenses are projected to increase approximately 2 percent to 3 percent over 2013 projected levels.
- Depreciation expense is projected to increase $110 million to $120 million over 2013 projected levels.
- Property taxes are projected to increase approximately $50 million to $55 million over 2013 projected levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $0 to $10 million from 2013 projected levels.
- AFUDC — equity is projected to increase approximately $10 million to $15 million over 2013 projected levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 506 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 represents 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 7. Non-GAAP Reconciliation

Xcel Energy's management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Thousands of Dollars)	**2013**	**2012**	**2013**	**2012**
Ongoing earnings	$ 384,056	$ 381,203	$ 817,526	$ 748,047
SPS 2004 FERC complaint case orders	(19,520)	—	(19,520)	—
Prescription drug tax benefit	—	16,944	—	16,944
Total continuing operations	**364,536**	**398,147**	**798,006**	**764,991**
Income (loss) from discontinued operations	216	(41)	173	68
GAAP earnings	**$ 364,752**	**$ 398,106**	**$ 798,179**	**$ 765,059**

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 $35 million was recorded in the third quarter of 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 $22.5 million and ongoing earnings exclude $19.5 million. See Note 5.

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 Sept. 30	
	2013	2012
Operating revenues:		
Electric and natural gas	$ 2,805,283	$ 2,707,222
Other	17,055	17,119
Total operating revenues	2,822,338	2,724,341
Income from continuing operations	364,536	398,147
Income (loss) from discontinued operations, net of tax	216	(41)
Net income	$ 364,752	$ 398,106
Earnings available to common shareholders	$ 364,752	$ 398,106
Weighted average diluted common shares outstanding	498,641	488,578
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	$ 0.81	$ 0.81
Xcel Energy Inc. and other costs	(0.04)	(0.03)
Ongoing [(a)] diluted earnings per share	**0.77**	**0.78**
SPS 2004 FERC complaint case orders [(b)]	(0.04)	—
Prescription drug tax benefit [(b)]	—	0.03
GAAP diluted earnings per share	**$ 0.73**	**$ 0.81**

	Nine Months Ended Sept. 30	
	2013	2012
Operating revenues:		
Electric and natural gas	$ 8,128,273	$ 7,523,181
Other	55,827	53,907
Total operating revenues	8,184,100	7,577,088
Income from continuing operations	798,006	764,991
Income from discontinued operations, net of tax	173	68
Net income	$ 798,179	$ 765,059
Earnings available to common shareholders	$ 798,179	$ 765,059
Weighted average diluted common shares outstanding	495,767	488,198
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	$ 1.77	$ 1.64
Xcel Energy Inc. and other costs	(0.12)	(0.10)
Ongoing [(a)] diluted earnings per share	**1.65**	**1.54**
SPS 2004 FERC complaint case orders [(b)]	(0.04)	—
Prescription drug tax benefit [(b)]	—	0.03
GAAP diluted earnings per share	**$ 1.61**	**$ 1.57**
Book value per share	$ 19.19	$ 18.15

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