XCEL ENERGY INC
Form 10-Q
October 25, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended Sept. 30, 2013
or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number: 001-3034
Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota	41-0448030
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
414 Nicollet Mall Minneapolis, Minnesota	55401
(Address of principal executive offices)	(Zip Code)

(612) 330-5500
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes x No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 18, 2013

Common Stock, $2.50 par value	497,639,485 shares

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This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. and its consolidated subsidiaries are also referred to herein as Xcel Energy. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

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PART I — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

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

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2013	2012	2013	2012
Net income	$364,752	$398,106	$798,179	$765,059
Other comprehensive income (loss)				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $686, $636, $3,918 and $1,905, respectively	1,179	911	1,675	2,738
Derivative instruments:				
Net fair value increase (decrease), net of tax of $14, $(5,913), $(2) and $(12,586), respectively	22	(8,853)	(9)	(19,188)
Reclassification of losses to net income, net of tax of $266, $296, $2,145 and $610, respectively	539	393	928	756
	561	(8,460)	919	(18,432)
Marketable securities:				
Net fair value increase (decrease), net of tax of $73, $(30), $56 and $89, respectively	115	(45)	79	129
Other comprehensive income (loss)	1,855	(7,594)	2,673	(15,565)
Comprehensive income	$366,607	$390,512	$800,852	$749,494

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in thousands)

	Nine Months Ended Sept. 30	
	2013	2012
Operating activities		
Net income	$798,179	$765,059
Remove income from discontinued operations	(173)	(68)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	740,623	707,630
Conservation and demand side management program amortization	5,024	5,511
Nuclear fuel amortization	76,447	79,171
Deferred income taxes	409,662	440,413
Amortization of investment tax credits	(4,973)	(4,656)
Allowance for equity funds used during construction	(63,147)	(44,504)
Equity earnings of unconsolidated subsidiaries	(22,379)	(22,150)
Dividends from unconsolidated subsidiaries	27,503	24,922
Share-based compensation expense	28,362	20,886
Net realized and unrealized hedging and derivative transactions	(12,011)	(90,123)
Changes in operating assets and liabilities:		
Accounts receivable	(108,488)	(125,803)
Accrued unbilled revenues	87,652	166,857
Inventories	(69,918)	55,511
Other current assets	6,060	(30,289)
Accounts payable	(3,297)	(118,276)
Net regulatory assets and liabilities	100,648	1,848
Other current liabilities	129,984	(35,283)
Pension and other employee benefit obligations	(159,592)	(181,281)
Change in other noncurrent assets	26,710	(38,790)
Change in other noncurrent liabilities	10,032	(4,664)
Net cash provided by operating activities	2,002,908	1,571,921
Investing activities		
Utility capital/construction expenditures	(2,454,198)	(1,805,843)
Proceeds from insurance recoveries	90,000	56,892
Allowance for equity funds used during construction	63,147	44,504
Purchases of investments in external decommissioning fund	(1,177,398)	(501,009)
Proceeds from the sale of investments in external decommissioning fund	1,172,597	501,009
Investment in WYCO Development LLC	(3,418)	(779)
Change in restricted cash	—	95,287
Other, net	(1,524)	343
Net cash used in investing activities	(2,310,794)	(1,609,596)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(300,000)	85,000
Proceeds from issuance of long-term debt	1,434,989	1,691,322

Repayments of long-term debt, including reacquisition premiums	(654,864)	(653,532)
Proceeds from issuance of common stock	229,420	5,878
Repurchase of common stock	—	(18,529)
Purchase of common stock for settlement of equity awards	—	(23,307)
Dividends paid	(382,148)	(362,568)
Net cash provided by financing activities	327,397	724,264
Net change in cash and cash equivalents	19,511	686,589
Cash and cash equivalents at beginning of period	82,323	60,684
Cash and cash equivalents at end of period	$101,834	$747,273
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(411,130)	$(436,296)
Cash received (paid) for income taxes, net	16,851	(6,257)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$299,209	$229,847
Issuance of common stock for reinvested dividends and 401(k) plans	54,963	51,350

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	Sept. 30, 2013	Dec. 31, 2012
Assets		
Current assets		
Cash and cash equivalents	$101,834	$82,323
Accounts receivable, net	786,874	718,046
Accrued unbilled revenues	575,711	663,363
Inventories	604,628	535,574
Regulatory assets	396,271	352,977
Derivative instruments	92,687	69,013
Deferred income taxes	325,972	32,528
Prepayments and other	236,764	171,315
Total current assets	3,120,741	2,625,139
Property, plant and equipment, net	25,342,578	23,809,348
Other assets		
Nuclear decommissioning fund and other investments	1,679,987	1,617,865
Regulatory assets	2,709,283	2,762,029
Derivative instruments	95,894	126,297
Other	178,169	200,008
Total other assets	4,663,333	4,706,199
Total assets	$33,126,652	$31,140,686
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$280,538	$258,155
Short-term debt	302,000	602,000
Accounts payable	965,572	959,093
Regulatory liabilities	208,943	168,858
Taxes accrued	335,846	334,441
Accrued interest	134,612	162,494
Dividends payable	139,333	131,748
Derivative instruments	26,729	32,482
Other	445,488	287,802
Total current liabilities	2,839,061	2,937,073
Deferred credits and other liabilities		
Deferred income taxes	5,186,944	4,434,909
Deferred investment tax credits	79,609	82,761
Regulatory liabilities	1,052,726	1,059,939
Asset retirement obligations	1,785,319	1,719,796
Derivative instruments	217,027	242,866
Customer advances	266,676	252,888
Pension and employee benefit obligations	998,212	1,163,265
Other	239,519	229,207
Total deferred credits and other liabilities	9,826,032	9,185,631

Commitments and contingencies		
Capitalization		
Long-term debt	10,914,273	10,143,905
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 497,625,709 and 487,959,516 shares outstanding at Sept. 30, 2013 and Dec. 31, 2012, respectively	1,244,064	1,219,899
Additional paid in capital	5,615,716	5,353,015
Retained earnings	2,797,486	2,413,816
Accumulated other comprehensive loss	(109,980)	(112,653)
Total common stockholders' equity	9,547,286	8,874,077
Total liabilities and equity	$33,126,652	$31,140,686

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended Sept. 30, 2013 and 2012						
Balance at June 30, 2012	487,286	$1,218,214	$5,316,658	$2,140,639	$(102,006)	$8,573,505
Net income				398,106		398,106
Other comprehensive loss					(7,594)	(7,594)
Dividends declared:						
Common stock				(132,729)		(132,729)
Issuances of common stock	327	818	8,679			9,497
Share-based compensation			9,378			9,378
Balance at Sept. 30, 2012	487,613	$1,219,032	$5,334,715	$2,406,016	$(109,600)	$8,850,163
Balance at June 30, 2013	497,296	$1,243,239	$5,595,906	$2,572,935	$(111,835)	$9,300,245
Net income				364,752		364,752
Other comprehensive income					1,855	1,855
Dividends declared:						
Common stock				(140,201)		(140,201)
Issuances of common stock	330	825	8,966			9,791
Share-based compensation			10,844			10,844
Balance at Sept. 30, 2013	497,626	$1,244,064	$5,615,716	$2,797,486	$(109,980)	$9,547,286

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Nine Months Ended Sept. 30, 2013 and 2012						
Balance at Dec. 31, 2011	486,494	$1,216,234	$5,327,443	$2,032,556	$(94,035)	$8,482,198
Net income				765,059		765,059
Other comprehensive loss					(15,565)	(15,565)
Dividends declared:						
Common stock				(391,599)		(391,599)
Issuances of common stock	1,819	4,548	19,449			23,997
Repurchase of common stock	(700)	(1,750)	(16,779)			(18,529)
Purchase of common stock for settlement of equity awards			(23,307)			(23,307)
Share-based compensation			27,909			27,909
Balance at Sept. 30, 2012	487,613	$1,219,032	$5,334,715	$2,406,016	$(109,600)	$8,850,163
Balance at Dec. 31, 2012	487,960	$1,219,899	$5,353,015	$2,413,816	$(112,653)	$8,874,077
Net income				798,179		798,179
Other comprehensive income					2,673	2,673
Dividends declared:						
Common stock				(414,509)		(414,509)
Issuances of common stock	9,666	24,165	228,751			252,916
Share-based compensation			33,950			33,950
Balance at Sept. 30, 2013	497,626	$1,244,064	$5,615,716	$2,797,486	$(109,980)	$9,547,286

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of Sept. 30, 2013 and Dec. 31, 2012; the results of its operations, including the components of net income and comprehensive income, and changes in stockholders' equity for the three and nine months ended Sept. 30, 2013 and 2012; and its cash flows for the nine months ended Sept. 30, 2013 and 2012. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2013 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2012 balance sheet information has been derived from the audited 2012 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2012. These notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2012, filed with the SEC on Feb. 22, 2013. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the consolidated financial statements in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2012, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

Balance Sheet Offsetting — In December 2011, the Financial Accounting Standards Board (FASB) issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (Accounting Standards Update (ASU) No. 2011-11), which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. In January 2013, the FASB issued Balance Sheet (Topic 210) – Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities (ASU No. 2013-01) to clarify the specific instruments that should be considered in these disclosures. These disclosure requirements do not affect the presentation of amounts in the consolidated balance sheets, and were effective for annual reporting periods beginning on or after Jan. 1, 2013, and interim periods within those annual reporting periods. Xcel Energy implemented the disclosure guidance effective Jan. 1, 2013, and the implementation did not have a material impact on its consolidated financial statements. See Note 8 for the required disclosures.

Comprehensive Income Disclosures — In February 2013, the FASB issued Comprehensive Income (Topic 220) — Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (ASU No. 2013-02), which requires detailed disclosures regarding changes in components of accumulated other comprehensive income and amounts reclassified out of accumulated other comprehensive income. These disclosure requirements do not change how net income or comprehensive income are presented in the consolidated financial statements. These disclosure requirements were effective for annual reporting periods beginning on or after Dec. 15, 2012, and interim periods within those annual reporting periods. Xcel Energy implemented the disclosure guidance effective Jan. 1, 2013, and the implementation did not have a material impact on its consolidated financial statements. See Note 13 for the required disclosures.

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3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2013	Dec. 31, 2012
Accounts receivable, net		
Accounts receivable	$838,271	$769,440
Less allowance for bad debts	(51,397)	(51,394)
	$786,874	$718,046

(Thousands of Dollars)	Sept. 30, 2013	Dec. 31, 2012
Inventories		
Materials and supplies	$228,302	$213,739
Fuel	201,728	189,425
Natural gas	174,598	132,410
	$604,628	$535,574

(Thousands of Dollars)	Sept. 30, 2013	Dec. 31, 2012
Property, plant and equipment, net		
Electric plant	$29,550,871	$28,285,031
Natural gas plant	3,942,182	3,836,335
Common and other property	1,467,811	1,480,558
Plant to be retired [(a)]	115,753	152,730
Construction work in progress	2,391,783	1,757,189
Total property, plant and equipment	37,468,400	35,511,843
Less accumulated depreciation	(12,462,716)	(12,048,697)
Nuclear fuel	2,157,940	2,090,801
Less accumulated amortization	(1,821,046)	(1,744,599)
	$25,342,578	$23,809,348

(a) In 2010, in response to the Clean Air Clean Jobs Act (CACJA), the Colorado Public Utilities Commission (CPUC) approved the early retirement of Cherokee Units 1, 2 and 3, Arapahoe Unit 3 and Valmont Unit 5 between 2011 and 2017. In 2011, Cherokee Unit 2 was retired and in 2012, Cherokee Unit 1 was retired. Amounts are presented net of accumulated depreciation.

4. Income Taxes

Except to the extent noted below, the circumstances set forth in Note 6 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2012 appropriately represent, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expired in September 2012. The statute of limitations applicable to Xcel Energy's 2009 federal income tax return expires in June 2015. In the third quarter of 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011. As of Sept. 30, 2013, the IRS had not proposed any material adjustments to tax years 2010 and 2011.

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State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Sept. 30, 2013, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2006
Minnesota	2009
Texas	2009
Wisconsin	2009

In the fourth quarter of 2012, the state of Colorado commenced an examination of tax years 2006 through 2009. In the first quarter of 2013, the state of Wisconsin commenced an examination of tax years 2009 through 2011. As of Sept. 30, 2013, no material adjustments had been proposed for either of these audits. There are currently no other state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (ETR). In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Sept. 30, 2013	Dec. 31, 2012
Unrecognized tax benefit — Permanent tax positions	$8.8	$4.7
Unrecognized tax benefit — Temporary tax positions	32.4	29.8
Total unrecognized tax benefit	$41.2	$34.5

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss (NOL) and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Sept. 30, 2013	Dec. 31, 2012
NOL and tax credit carryforwards	$(40.1)	$(33.5)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS and state audits progress. As the IRS examination moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $35 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at Sept. 30, 2013 and Dec. 31, 2012 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2013 or Dec. 31, 2012.

Tangible Property Regulations — In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with the acquisition, production and improvement of tangible property. As Xcel Energy had adopted certain utility-specific guidance previously issued by the IRS, the issuance is not expected to have a material impact on its consolidated financial statements.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 12 to the consolidated financial statements included in Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2012 and in Note 5 to Xcel Energy Inc.’s Quarterly Reports on Form 10-Q for the quarter periods ended March 31, 2013 and June 30, 2013, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

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NSP-Minnesota

Recently Concluded Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

NSP-Minnesota – Minnesota 2013 Electric Rate Case — In November 2012, NSP-Minnesota filed a request with the 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 (FTY), 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.

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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 (CON) 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.

Pending Regulatory Proceedings — North Dakota Public Service Commission (NDPSC)

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 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.

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Recently Concluded Regulatory Proceedings — South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota – South Dakota 2012 Electric Rate Case — In March 2013, NSP-Minnesota and the SDPUC Staff reached a settlement agreement that provides for a base rate increase of approximately $11.6 million and the implementation of a new rider. On Oct. 1, 2013, NSP-Minnesota filed its compliance report consistent with the settlement to recover the revenue requirement on the specific major capital additions and incremental property tax resulting in recovery of $8.7 million for 2014.

NSP-Wisconsin

Pending Regulatory Proceedings — Public Service Commission of Wisconsin (PSCW)

NSP-Wisconsin – Wisconsin 2014 Electric and Gas Rate Case — On May 31, 2013, NSP-Wisconsin filed a request with the 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 $34.0 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.

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PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo – Colorado 2013 Gas Rate Case — In December 2012, PSCo filed a multi-year request with the 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 recommended an incremental base revenue decrease of $1.1 million, based on a historic test year (HTY), an ROE of 9 percent and an equity ratio of 52 percent. The Office of Consumer Counsel (OCC) recommended an incremental base revenue increase of $15.4 million based on an HTY, an ROE of 9 percent and equity ratio of 51.03 percent and other adjustments. The recommended incremental base revenues are inclusive of proposed changes to the level of integrity management costs moved from the PSIA rider to base rates.

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. This requested increase includes amounts to be transferred from the PSIA rider mechanism. The deficiency, based on an FTY, was $30.6 million.

In October 2013, the ALJ issued her recommendation. As part of this decision, she recommended the use of an HTY, an ROE of 9.72 percent and an equity ratio of 56 percent. The ALJ also recommended to reject PSCo's proposed changes to the PSIA, instead leaving the current rider in effect and suggested that changes be presented in a separate application. The recommended incremental base revenue increase was approximately $15.0 million.

The following table summarizes the CPUC Staff, OCC and ALJ's recommendations:

(Millions of Dollars)	CPUC Staff	OCC	ALJ
PSCo deficiency based on a FTY	$44.8	$44.8	$44.8
Move to HTY	(1.6)	(1.6)	(1.6)
ROE and capital structure adjustments	(20.8)	(20.0)	(7.7)
Move to a 13 month average from year end rate base	(5.7)	(3.2)	(3.3)
Remove pension asset	(5.9)	—	—
Reduce pension expense net of corrections	(1.6)	—	—
Remove incentive compensation	(3.5)	(0.2)	(0.2)
Challenge known and measurable	—	(9.0)	—
Eliminate depreciation annualization	—	(1.8)	—
Revenue adjustments	(4.1)	(1.4)	(1.4)
Resulting tax impacts	1.5	4.7	(0.2)
Other adjustments	(4.2)	3.1	(1.2)
Remove PSIA from base rates	(14.2)	(14.2)	—
Recommendation	$(15.3)	$1.2	$29.2

Neutralize PSIA - base rate transfer	14.2	14.2	(14.2)
Incremental base revenue	$(1.1)	$15.4	$15.0

Exceptions and corresponding responses are due to be filed in November 2013 and a CPUC decision is expected in December 2013.

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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 (CPCN) proceeding for the construction of the Sun Valley Steam Center. A decision on the settlement is expected at the end of 2013.

PSCo – Annual Electric Earnings Test — An earnings sharing mechanism is used to apply prospective electric rate adjustments for earnings in the prior year over PSCo's authorized ROE threshold of 10 percent. In June 2013, PSCo entered into a comprehensive settlement of issues with all parties associated with the 2012 earnings test, resulting in a refund obligation of approximately $8.2 million to be refunded through June 2014. As of Sept. 30, 2013, PSCo has also recognized management's best estimate of an accrual for the 2013 test year.

PSCo – Production Formula Rate ROE Complaint — On Aug. 30, 2013, PSCo's wholesale production customers filed a complaint with the Federal Energy Regulatory Commission (FERC), and requested it reduce the stated ROEs ranging from 10.1 percent through 10.4 percent to 9.04 percent in the PSCo power sales formula rates, which could reduce revenues approximately $2 million per year prospectively. The matter is currently pending the FERC's action.

Renewable Energy Credit (REC) Sharing — In May 2011, the CPUC determined that margin sharing on stand-alone REC transactions would be shared 20 percent to PSCo and 80 percent to customers and ultimately becoming 10 percent to PSCo and 90 percent to customers by 2014. The CPUC also approved a change to the treatment of hybrid REC trading margins (RECs that are bundled with energy) that allows the customers' share of the margins to be netted against the renewable energy standard adjustment (RESA) regulatory asset balance.

In March 2012, the CPUC approved an annual margin sharing on the first $20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the $20 million are to be shared 90 percent to the customers and 10 percent to PSCo. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the RESA regulatory asset balance. For the three months ended Sept. 30, 2013 and 2012, PSCo credited the RESA regulatory asset balance $6.1 million and $6.2 million, respectively. The cumulative credit to the RESA regulatory asset balance was $99.4 million and $82.8 million at Sept. 30, 2013 and Dec. 31, 2012, respectively. The credits include the customers' share of REC trading margins and the customers' share of carbon offset funds.

This sharing mechanism will be effective through 2014. The CPUC is then expecting to review the framework and evidence regarding actual deliveries before determining to continue the sharing mechanism.

Electric Commodity Adjustment (ECA) / RESA Adjustment — In July 2013, PSCo advised the CPUC that it had inadvertently allocated purchased power expense between the deferred accounts for the ECA and the RESA from 2010 to 2012. In order to be in compliance with a series of CPUC orders, PSCo proposed to transfer from the RESA deferred account to the ECA deferred account approximately $26.2 million and to amortize the recovery of this amount over 12 months. The transfer, if approved, would mainly impact the timing of recovery. In addition, interest of $2.6 million was accrued on the amount related to the RESA. The PSCo application to change the ECA tariff to address this issue has been set for hearing in December 2013 by the CPUC.

ECA Prudence Review — In September 2013, the CPUC Staff requested that the 2012 annual ECA prudence review be set for hearing. The prudence review, as determined by the ALJ, will primarily consider if replacement power costs during the outage of jointly owned facilities were properly allocated between wholesale and retail customers. A hearing is expected in January 2014.

2012 PSIA Report — In April 2013, PSCo filed its 2012 PSIA report. The OCC and CPUC Staff requested the CPUC set the matter for hearing to review in detail the information provided, including a review of the prudence of expenditures in 2012, and to develop standards for future filings. The CPUC approved the request on July 10, 2013 and assigned the matter to an ALJ.

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Next steps in the procedural schedule are as follows:

- Direct testimony - Nov. 5, 2013;
- Intervenor testimony - Jan. 7, 2014;
- Rebuttal testimony - Feb. 6, 2014;
- Evidentiary hearing - March 3 - March 7, 2014;
- Initial brief - March 28, 2014; and
- Reply brief - April 11, 2014.

SPS

Recently Concluded Regulatory Proceedings — Public Utility Commission of Texas (PUCT)

SPS – Texas 2012 Electric Rate Case — In November 2012, SPS filed an electric rate case in Texas with the PUCT for an increase in annual revenue of approximately $90.2 million. The rate filing is based on a historic twelve month test year ended June 30, 2012 (adjusted for known and measurable changes), a requested ROE of 10.65 percent, an electric rate base of $1.15 billion and an equity ratio of 52 percent.

In June 2013, the PUCT approved a settlement agreement in which SPS' base rate increased by $37 million, effective May 1, 2013 and by an additional $13.8 million on Sept. 1, 2013. In addition, the settlement allows SPS to file a transmission cost recovery adjustment rider in the fourth quarter of 2013 and for those rates to become effective on an interim basis in January 2014. Under the settlement, SPS cannot file another base rate case in 2013, but there are no restrictions on SPS filing a base rate case in 2014.

Pending Regulatory Proceedings — New Mexico Public Regulation Commission (NMPRC)

SPS – New Mexico 2014 Electric Rate Case — In December 2012, SPS filed an electric rate case in New Mexico with the 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.

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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.

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.

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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.

Purchase and Sale Agreement for Certain Texas Transmission Assets — On March 29, 2013, SPS entered into a purchase and sale agreement with Sharyland Distribution and Transmission Services, LLC (Sharyland) for the sale of certain segments of SPS’ transmission lines and two related substations for a base purchase price of $37 million, subject to adjustments for unplanned capital expenditures. The transaction is subject to various regulatory approvals including that of the FERC.

On April 29, 2013, SPS made filings regarding the planned transaction with the PUCT, the NMPRC and the FERC. If approved, the sale is expected to close by the end of 2013. The FERC approved the transaction in August 2013 and on Sept. 20, 2013 SPS filed an unopposed stipulation at the PUCT resolving all issues related to the SPS items in the joint application SPS filed together with Sharyland. In the proposed settlement to the PUCT, the Texas retail jurisdiction would be allocated 45 percent of the net pre-tax gain on sale and this amount would be shared 60 percent with customers and 40 percent would be retained by SPS.

On Sept. 12, 2013, the NMPRC Staff and the NMAG filed testimony in support of the sale of the transmission assets. Both parties proposed that SPS’ New Mexico retail customers should retain 100 percent of any New Mexico jurisdictional share of the gain on sale. On Sept. 27, 2013, SPS filed rebuttal testimony before the NMPRC disputing the positions presented by the NMPRC Staff and the NMAG. An evidentiary hearing was held on Oct. 8, 2013.

Decisions are expected from the NMPRC and PUCT in the fourth quarter of 2013.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5, the circumstances set forth in Notes 12, 13 and 14 to the consolidated financial statements included in Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2012, appropriately represent, in all material respects, the current status of commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to Xcel

Energy's financial position.

Purchased Power Agreements

Under certain purchased power agreements, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific purchased power agreements create a variable interest in the associated independent power producing entity.

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The Xcel Energy utility subsidiaries had approximately 3,338 megawatts (MW) and 3,324 MW of capacity under long-term purchased power agreements as of Sept. 30, 2013 and Dec. 31, 2012, respectively, with entities that have been determined to be variable interest entities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. These agreements have expiration dates through the year 2033.

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of Sept. 30, 2013 and Dec. 31, 2012, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

The following table presents guarantees and bond indemnities issued and outstanding for Xcel Energy Inc.:

(Millions of Dollars)	Sept. 30, 2013	Dec. 31, 2012
Guarantees issued and outstanding	$54.8	$69.5
Current exposure under these guarantees	17.8	17.9
Bonds with indemnity protection	31.9	29.6

Indemnification Agreements

Xcel Energy Inc. and its subsidiaries provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

Ashland Manufactured Gas Plant (MGP) Site — NSP-Wisconsin has been named a potentially responsible party (PRP) for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Ashland site) includes property owned by NSP-Wisconsin, which was a site previously operated by a predecessor company as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park), on which an unaffiliated third party previously operated a sawmill and conducted creosote treating operations; and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

The U.S. Environmental Protection Agency (EPA) issued its Record of Decision (ROD) in 2010, which describes the preferred remedy the EPA has selected for the cleanup of the Ashland site. In 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, for future remediation at the site. The special notice letters requested that those PRPs participate in negotiations with the EPA regarding how the PRPs intended to conduct or pay for the remediation at the Ashland site. As a result of those settlement negotiations, the EPA agreed to segment the Ashland site into separate areas. The first area (Phase I Project Area) includes soil and groundwater in Kreher Park and the Upper Bluff. The second area includes the Sediments.

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In October 2012, a settlement among the EPA, the Wisconsin Department of Natural Resources (WDNR), the Bad River and Red Cliff Bands of the Lake Superior Tribe of Chippewa Indians and NSP-Wisconsin was approved by the U.S. District Court for the Western District of Wisconsin. This settlement resolves claims against NSP-Wisconsin for its alleged responsibility for the remediation of the Phase I Project Area. Under the terms of the settlement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area, but does not admit any liability with respect to the Ashland site. The settlement reflects a cost estimate for the clean up of the Phase I Project Area of $40 million. The settlement also resolves claims by the federal, state and tribal trustees against NSP-Wisconsin for alleged natural resource damages at the Ashland site, including both the Phase I Project Area and the Sediments. As part of the settlement, NSP-Wisconsin has conveyed approximately 1,390 acres of land to the State of Wisconsin and tribal trustees. Fieldwork to address the Phase I Project Area at the Ashland site began at the end of 2012 and continues.

Negotiations between the EPA and NSP-Wisconsin regarding who will pay or perform the cleanup of the Sediments are ongoing. In August and September 2013, NSP-Wisconsin performed field studies in the Sediments to gather more data about site conditions. The data from that investigation will be received and reported in November 2013. Also, in September 2013, the EPA requested NSP-Wisconsin consider re-submitting another proposal to perform a wet dredge pilot study for a portion of the Sediments. NSP-Wisconsin previously submitted a proposal for a wet dredge pilot study in 2011. The EPA's ROD for the Ashland site includes estimates that the cost of the preferred remediation related to the Sediments is between $63 million and $77 million, with a potential deviation in such estimated costs of up to 50 percent higher to 30 percent lower.

In August 2012, NSP-Wisconsin also filed litigation against other PRPs for their share of the cleanup costs for the Ashland site. Trial for this matter has been rescheduled for April 2015. Negotiations between the EPA, NSP-Wisconsin and several of the other PRPs regarding the PRPs' fair share of the cleanup costs for the Ashland site are also ongoing.

At Sept. 30, 2013 and Dec. 31, 2012, NSP-Wisconsin had recorded a liability of $101.2 million and $103.7 million, respectively, for the Ashland site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $19.5 million and $20.1 million, respectively, was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, potential contributions by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

NSP-Wisconsin has deferred the estimated site remediation costs, as a regulatory asset, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin retail rate case process. Under an existing PSCW policy, utilities have recovered remediation costs for MGPs in natural gas rates, amortized over a four- to six-year period. The PSCW historically has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation.

In the last rate case decision, the PSCW recognized the potential magnitude of the future liability for the cleanup at the Ashland site and granted an exception to its existing policy at the request of NSP-Wisconsin. The elements of this exception include: 1) approval to begin recovery of estimated Phase 1 Project costs beginning on Jan. 1, 2013; 2) approval to amortize these estimated costs over a ten-year period; and 3) approval to apply a three percent carrying cost to the unamortized regulatory asset. Implementation of this exception will help mitigate the rate impact to natural gas customers and the risk to NSP-Wisconsin from a longer amortization period.

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Environmental Requirements

Greenhouse Gas (GHG) New Source Performance Standard (NSPS) Proposal and Emission Guideline for Existing Sources — In September 2013, the EPA re-proposed a GHG NSPS for newly constructed power plants which seeks to establish carbon dioxide (CO_2) emission rates for coal-fired power plants that reflect emission reductions using partial carbon capture and storage technology (CCS). The EPA's proposed CO_2 emission limits for gas-fired power plants reflect emissions levels from combined cycle technology with no CCS. The EPA continues to propose that the NSPS not apply to modified or reconstructed existing power plants. In addition, installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program. It is not possible to evaluate the impact of the re-proposed NSPS until its final requirements are known.

In June 2013, President Obama issued a memorandum directing the EPA to develop GHG emission standards for existing power plants. The memorandum anticipates the EPA will issue a proposed GHG emission standard for existing power plants in June 2014. It is not possible to evaluate the impact of existing source standards until the upcoming proposal and final requirements are known.

Cross-State Air Pollution Rule (CSAPR) — In 2011, the EPA issued the CSAPR to address long range transport of particulate matter (PM) and ozone by requiring reductions in sulfur dioxide (SO_2) and nitrogen oxide (NOx) from utilities in the eastern half of the United States. For Xcel Energy, the rule would have applied in Minnesota, Wisconsin and Texas. The CSAPR would have set more stringent requirements than the proposed Clean Air Transport Rule and specifically would have required plants in Texas to reduce their SO_2 and annual NOx emissions. The rule also would have created an emissions trading program.

In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the CSAPR and remanded it back to the EPA. The D.C. Circuit stated that the EPA must continue administering the Clean Air Interstate Rule (CAIR) pending adoption of a valid replacement. In June 2013, the U.S. Supreme Court elected to review the D.C. Circuit's 2012 decision to vacate the CSAPR. The Court has ordered the parties to file briefs in the appeal this fall and will hear arguments in December 2013. The Court will likely issue a decision by June 2014.

As the EPA continues administering the CAIR while the CSAPR or a replacement rule is pending, Xcel Energy expects to comply with the CAIR as described below.

CAIR — In 2005, the EPA issued the CAIR to further regulate SO_2 and NOx emissions. The CAIR applies to Texas and Wisconsin. The CAIR does not apply to Minnesota.

Under the CAIR's cap and trade structure, companies can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. NSP-Wisconsin purchased allowances in 2012 and plans to continue to purchase allowances in 2013 to comply with the CAIR. In the SPS region, installation of low-NOx combustion control technology was completed in 2012 on Tolk Unit 1. SPS plans to install the same combustion control technology on Tolk Unit 2 in 2014. These installations will reduce or eliminate SPS' need to purchase NOx emission allowances. In addition, SPS has sufficient SO_2 allowances to comply with the CAIR in 2013. At Sept. 30, 2013, the estimated annual CAIR NOx allowance cost for Xcel Energy did not have a material impact on the results of operations, financial position or cash flows.

Federal Clean Water Act - Effluent Limitations Guidelines (ELG) — In June 2013, the EPA published a proposed ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. Refuse derived fuel, biomass and other alternatively fueled power plants are not addressed by the proposed revisions. The proposed rule identifies four potential regulatory options and invites comments on those regulatory approaches. The options differ in the number of waste streams covered, size of the units controlled and stringency of controls. A final rule is anticipated in 2014. Under the current proposed rule, facilities would need to comply as soon as possible after July 2017 but no later than July 2022. The impact of this rule on Xcel Energy is uncertain at this time.

Regional Haze Rules — In 2005, the EPA finalized amendments to its regional haze rules, known as best available retrofit technology (BART), which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. Xcel Energy generating facilities in several states are subject to BART requirements. Individual states were required to identify the facilities located in their states that will have to reduce SO_2, NOx and PM emissions under BART and then set emissions limits for those facilities.

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PSCo

In 2011, the Colorado Air Quality Control Commission approved a BART state implementation plan (SIP) incorporating the Colorado CACJA emission reduction plan, which will satisfy regional haze requirements. The Colorado legislature enacted a statute approving the SIP (the Colorado SIP), which was signed into law in 2011. Subsequently, the Colorado Mining Association (CMA) challenged the Colorado SIP in a Colorado District Court. In June 2012, the CMA's appeal was dismissed. The CMA appealed this decision, which is now pending in the Colorado Court of Appeals.

In September 2012, the EPA granted final approval of the Colorado SIP, including the CACJA emission reduction plan for PSCo, as satisfying BART requirements. The emission controls are expected to be installed between 2014 and 2017. Projected costs for emission controls at the Hayden and Pawnee plants are $343.0 million. PSCo expects the cost of any required capital investment will be recoverable from customers.

In March 2013, WildEarth Guardians petitioned the U.S. Court of Appeals for the 10th Circuit to review the EPA's decision approving the Colorado SIP. WildEarth Guardians has stated that it will challenge the BART determination made for Comanche Units 1 and 2, which was a separate determination that was not part of the CACJA emission reduction plan. In comments before the EPA, WildEarth Guardians urged that current emission limitations be made more stringent, or that Selective Catalytic Reduction (SCR) be added to the units. PSCo has intervened in the case.

In 2010, two environmental groups petitioned the U.S. Department of the Interior (DOI) to certify that 12 coal-fired boilers and one coal-fired cement kiln in Colorado are contributing to visibility problems in Rocky Mountain National Park. The following PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege that the Colorado BART rule is inadequate to satisfy the Clean Air Act (CAA) mandate of ensuring reasonable further progress towards restoring natural visibility conditions in the park. It is not known when the DOI will rule on the petition.

NSP-Minnesota

In 2009, the Minnesota Pollution Control Agency (MPCA) approved the SIP for Minnesota (the Minnesota SIP), and submitted it to the EPA for approval. The MPCA selected the BART controls for Sherco Units 1 and 2 to improve visibility in the national parks. The MPCA concluded SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The MPCA's source-specific BART controls for Sherco Units 1 and 2 consist of combustion controls for NOx and scrubber upgrades for SO_2. The combustion controls have been installed on Sherco Units 1 and 2. The scrubber upgrades are underway and scheduled to be completed by January 2015.

The EPA's preliminary review of the Minnesota SIP in 2011 indicated that SCR controls should be added to Sherco Units 1 and 2. Subsequently, the EPA and MPCA both determined that CSAPR meets BART requirements for purposes of the Minnesota SIP. In addition, the MPCA retained its source-specific BART determination for Sherco Units 1 and 2 from the 2009 Minnesota SIP. The EPA approved the Minnesota SIP for electric generating units (EGUs), and also approved the source-specific emission limits for Sherco Units 1 and 2 as strengthening the Minnesota SIP, but avoided characterizing them as BART limits.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit. The Court denied intervention in the case to NSP-Minnesota and other regulated parties who petitioned to intervene. In June 2013, the Court ordered this case to be held in abeyance until the U.S. Supreme Court decides the CSAPR case.

NSP-Minnesota's estimated cost for meeting the BART, regional haze and other CAA requirements is approximately $50 million, of which $37 million has already been spent on projects to reduce NOx emissions on Sherco Units 1 and 2. Xcel Energy anticipates that all costs associated with BART compliance will be fully recoverable through regulatory recovery mechanisms. If the above litigation results in further EPA proceedings concerning the Minnesota SIP, such proceedings may consider whether SCRs should be required for Sherco Units 1 and 2.

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In addition to the regional haze rules, there are other visibility rules related to a program called the Reasonably Attributable Visibility Impairment (RAVI) program. In 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to RAVI and, if so, whether the level of controls required by the MPCA is appropriate. The EPA plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program. It is not yet known when the EPA will publish a proposal under RAVI or what that proposal will entail. In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club. The lawsuit alleges that the EPA has failed to perform a nondiscretionary duty to determine BART for the Sherco Units 1 and 2 under the RAVI program. The EPA filed an answer denying the allegations and asserting that it did not have a nondiscretionary duty under the RAVI program. The Court denied NSP-Minnesota's motion to intervene in July 2013. NSP-Minnesota appealed this decision to the U.S. Court of Appeals for the Eighth Circuit.

SPS
Harrington Units 1 and 2 are potentially subject to BART. Texas has developed a SIP (the Texas SIP) that finds the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs. It is not yet known how the D.C. Circuit's reversal of the CSAPR may impact the EPA's approval of the Texas SIP.

Legal Contingencies

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental Litigation

Comer vs. Xcel Energy Inc. et al. — In May 2011, less than a year after their initial lawsuit was dismissed, plaintiffs in this purported class action lawsuit filed a second lawsuit against more than 85 utility, oil, chemical and coal companies in the U.S. District Court in Mississippi. The complaint alleges defendants' CO_2 emissions intensified the strength of Hurricane Katrina and increased the damage plaintiffs purportedly sustained to their property. Plaintiffs base their claims on public and private nuisance, trespass and negligence. Among the defendants named in the complaint are Xcel Energy Inc., SPS, PSCo, NSP-Wisconsin and NSP-Minnesota. The amount of damages claimed by plaintiffs is unknown. The defendants believe this lawsuit is without merit and filed a motion to dismiss the lawsuit. In March 2012, the U.S. District Court granted this motion for dismissal. In April 2012, plaintiffs appealed this decision to the U.S. Court of Appeals for the Fifth Circuit. In May 2013, the Fifth Circuit affirmed the district court's dismissal of this lawsuit. Plaintiffs elected not to seek further review of this decision, which brings this litigation to a close. No accrual was recorded for this matter.

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Employment, Tort and Commercial Litigation

Merricourt Wind Project Litigation — In April 2011, NSP-Minnesota terminated its agreements with enXco Development Corporation (enXco) for the development of a 150 MW wind project in southeastern North Dakota. NSP-Minnesota's decision to terminate the agreements was based in large part on the adverse impact this project could have on endangered or threatened species protected by federal law and the uncertainty in cost and timing in mitigating this impact. NSP-Minnesota also terminated the agreements due to enXco's nonperformance of certain other conditions, including failure to obtain a Certificate of Site Compatibility and the failure to close on the contracts by an agreed upon date of March 31, 2011. NSP-Minnesota recorded a $101 million deposit in the first quarter of 2011, which was collected in April 2011. In May 2011, NSP-Minnesota filed a declaratory judgment action in the U.S. District Court in Minnesota to obtain a determination that it acted properly in terminating the agreements. enXco also filed a separate lawsuit in the same court seeking approximately $240 million for an alleged breach of contract. NSP-Minnesota believes enXco's lawsuit is without merit. In October 2012, NSP-Minnesota filed a motion for summary judgment. In April 2013, the U.S. District Court granted NSP-Minnesota's motion and entered judgment in its favor. In April 2013, enXco filed a notice of appeal to the Eighth Circuit. It is uncertain when the Eighth Circuit will decide this appeal. Although Xcel Energy believes the likelihood of loss is remote based on existing case law and the U.S. District Court's April 2013 decision, it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. No accrual has been recorded for this matter.

Exelon Wind (formerly John Deere Wind) Complaint — Several lawsuits in Texas state and federal courts and regulatory proceedings have arisen out of a dispute concerning SPS' payments for energy and capacity produced from the Exelon Wind subsidiaries' projects. There are two main areas of dispute. First, Exelon Wind claims that it established legally enforceable obligations (LEOs) for each of its 12 wind facilities in 2005 through 2008 that require SPS to buy power based on SPS' forecasted avoided cost as determined in 2005 through 2008. Although SPS has refused to accept Exelon Wind's LEOs, SPS accepts that it must take energy from Exelon Wind under SPS' PUCT-approved Qualifying Facilities (QF) Tariff. Second, Exelon Wind has raised various challenges to SPS' PUCT-approved QF Tariff, which became effective in August 2010. The state and federal lawsuits and regulatory proceedings are in various stages of litigation. SPS believes the likelihood of loss in these lawsuits and proceedings is remote based primarily on existing case law and while it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome, SPS believes such loss would not be material based upon its belief that it would be permitted to recover such costs, if needed, through its various fuel clause mechanisms. No accrual has been recorded for this matter.

Pacific Northwest FERC Refund Proceeding — In July 2001, the FERC ordered a preliminary hearing to determine whether there were unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for December 2000 through June 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC's orders in this proceeding with the Ninth Circuit.

In an order issued in August 2007, the Ninth Circuit remanded the proceeding back to the FERC and indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The Ninth Circuit denied a petition for rehearing in April 2009, and the mandate was issued.

The FERC issued an order on remand establishing principles for the review proceeding in October 2011. In September 2012, the City of Seattle filed its direct case against PSCo and other Pacific Northwest sellers claiming refunds for the period January 2000 through June 2001. The City of Seattle indicated that for the period June 2000 through June 2001 PSCo had sales to the City of Seattle of approximately $50 million. The City of Seattle did not identify specific instances of unlawful market activity by PSCo, but rather based its claim for refunds on market dysfunction in the Western markets. PSCo submitted its answering case in December 2012.

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In April 2013, the FERC issued an order on rehearing. The FERC confirmed that the City of Seattle would be able to attempt to obtain refunds back from January 2000, but reaffirmed the transaction-specific standard that the City of Seattle and other complainants would have to comply with to obtain refunds. In addition, the FERC rejected the imposition of any market-wide remedies. Although the FERC order on rehearing established the period for which the City of Seattle could seek refunds as January 2000 through June 2001, it is unclear what claim the City of Seattle has against PSCo prior to June 2000. In the proceeding, The City of Seattle does not allege specific misconduct or tariff violations by PSCo but instead asserts generally that the rates charged by PSCo and other sellers were excessive. A FERC hearing on the issue is presently in progress. An ALJ initial decision is expected in December 2013.

Preliminary calculations of the City of Seattle's claim for refunds from PSCo are approximately $28 million excluding interest. PSCo has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, PSCo is currently unable to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. In making this assessment, PSCo considered two factors. First, not withstanding PSCo's view that the City of Seattle has failed to apply the standard that the FERC has established in this proceeding, and the recognition that this case raises a novel issue and the FERC's standard has been challenged on appeal to the Ninth Circuit, the outcome of such an appeal cannot be predicted with any certainty. Second, PSCo would expect to make equitable arguments against refunds even if the City of Seattle were to establish that it was overcharged for transactions. If a loss were sustained, PSCo would attempt to recover those losses from other PRPs. No accrual has been recorded for this matter.

Nuclear Power Operations and Waste Disposal

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the U.S. Department of Energy's (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the United States and NSP-Minnesota. NSP-Minnesota sought contract damages in this lawsuit through Dec. 31, 2004. In September 2007, the court awarded NSP-Minnesota $116.5 million in damages. In August 2007, NSP-Minnesota filed a second complaint; this lawsuit claimed damages for the period Jan. 1, 2005 through Dec. 31, 2008.

In July 2011, the United States and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial $100 million payment from the United States to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013, estimated to be an additional $100 million. The settlement does not address costs for used fuel storage after 2013; such costs could be the subject of future litigation. NSP-Minnesota received the initial $100 million payment in August 2011, the second installment of $18.6 million in March 2012, and the third installment of $20.7 million in October 2012. NSP-Minnesota's claim submission for the fourth installment, in the amount of $42.8 million, was filed May 15, 2013 for costs incurred in 2012. The DOE recommended payment of $42.6 million for this claim in August 2013. Amounts received from the installments were subsequently credited to customers, except for approved reductions such as legal costs and amounts set aside to be credited through another regulatory mechanism.

In NSP-Wisconsin's 2012 Electric and Gas Rate Case, the PSCW authorized NSP-Wisconsin to utilize the proceeds from the second and third installments to be included as a reduction of the 2013 electric rate increase. In December 2012, the MPUC approved NSP-Minnesota's triennial nuclear decommissioning filing which required NSP-Minnesota to place the Minnesota retail portion of the DOE settlement payments for the third installment of $15.3 million and the anticipated fourth installment in 2013 into the nuclear decommissioning fund when received. NSP-Minnesota proposed to contribute the North Dakota retail portion of the second, third and fourth installments to the nuclear decommissioning fund to offset the increase in the decommissioning accrual that was included in the 2012 North Dakota electric rate case. That filing is pending NDPSC action.

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

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Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2013		Twelve Months Ended Dec. 31, 2012	
Borrowing limit	$2,450		$2,450	
Amount outstanding at period end	302		602	
Average amount outstanding	347		403	
Maximum amount outstanding	491		634	
Weighted average interest rate, computed on a daily basis	0.27	%	0.35	%
Weighted average interest rate at period end	0.25		0.36	

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Sept. 30, 2013 and Dec. 31, 2012, there were $18.8 million and $14.2 million of letters of credit outstanding, respectively, under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

At Sept. 30, 2013, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility (a)	Drawn (b)	Available
Xcel Energy Inc.	$800.0	$258.0	$542.0
PSCo	700.0	6.9	693.1
NSP-Minnesota	500.0	44.9	455.1
SPS	300.0	—	300.0
NSP-Wisconsin	150.0	11.0	139.0
Total	$2,450.0	$320.8	$2,129.2

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

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at Sept. 30, 2013 and Dec. 31, 2012.

Long-Term Borrowings and Other Financing Instruments

PSCo — In March 2013, 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. — In May 2013, Xcel Energy Inc. issued $450 million of 0.75 percent senior unsecured notes due May 9, 2016.

NSP-Minnesota — In May 2013, NSP-Minnesota issued $400 million of 2.60 percent first mortgage bonds due May 15, 2023.

SPS — In August 2013, SPS issued $100 million of 4.50 percent first mortgage bonds due Aug. 15, 2041. Including the $300 million of this series previously issued, total principal outstanding for this series is $400 million.

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Issuances of Common Stock — 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. had issued 7.7 million shares of common stock through this program and received cash proceeds of $223.1 million, net of $2.3 million in fees and commissions. The proceeds from the issuances of common stock were used to repay short-term debt, infuse equity into the utility subsidiaries and for other general corporate purposes.

Debt Redemption — 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.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with discounted cash flow or option pricing models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on Xcel Energy’s evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

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Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include financial transmission rights (FTRs) purchased from Midcontinent Independent Transmission System Operator, Inc. (MISO). FTRs purchased from MISO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in the fuel clause adjustment, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and Prairie Island nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. The MPUC approved NSP-Minnesota's proposed change in escrow fund investment strategy in September 2012. The MPUC approved an asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were $202.4 million and $135.8 million at Sept. 30, 2013 and Dec. 31, 2012, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $65.3 million and $46.4 million at Sept. 30, 2013 and Dec. 31, 2012, respectively.

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The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Sept. 30, 2013 and Dec. 31, 2012:

	Sept. 30, 2013				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$74,103	$74,103	$—	$—	$74,103
Commingled funds	436,533	—	438,906	—	438,906
International equity funds	65,529	—	68,164	—	68,164
Private equity investments	43,286	—	—	52,474	52,474
Real estate	41,645	—	—	51,356	51,356
Debt securities:					
Government securities	34,475	—	28,946	—	28,946
U.S. corporate bonds	86,719	—	88,561	—	88,561
International corporate bonds	15,999	—	15,976	—	15,976
Municipal bonds	207,417	—	197,917	—	197,917
Equity securities:					
Common stock	410,820	537,189	—	—	537,189
Total	$1,416,526	$611,292	$838,470	$103,830	$1,553,592

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $87.8 million of equity investments in unconsolidated subsidiaries and $38.6 million of miscellaneous investments.

	Dec. 31, 2012				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$246,904	$237,938	$8,966	$—	$246,904
Commingled funds	396,681	—	417,583	—	417,583
International equity funds	66,452	—	69,481	—	69,481
Private equity investments	27,943	—	—	33,250	33,250
Real estate	32,561	—	—	39,074	39,074
Debt securities:					
Government securities	21,092	—	21,521	—	21,521
U.S. corporate bonds	162,053	—	169,488	—	169,488
International corporate bonds	15,165	—	16,052	—	16,052
Municipal bonds	21,392	—	23,650	—	23,650
Asset-backed securities	2,066	—	—	2,067	2,067
Mortgage-backed securities	28,743	—	—	30,209	30,209
Equity securities:					
Common stock	379,093	420,263	—	—	420,263
Total	$1,400,145	$658,201	$726,741	$104,600	$1,489,542

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $91.2 million of equity investments in unconsolidated subsidiaries and $37.1 million of miscellaneous investments.

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The following tables present the changes in Level 3 nuclear decommissioning fund investments for the three and nine months ended Sept. 30, 2013 and 2012:

(Thousands of Dollars)	July 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3	Sept. 30, 2013
Private equity investments	$45,590	$6,790	$—	$94	$—	$52,474
Real estate	38,140	11,288	—	1,928	—	51,356
Total	$83,730	$18,078	$—	$2,022	$—	$103,830

(Thousands of Dollars)	July 1, 2012	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3	Sept. 30, 2012
Private equity investments	$23,303	$—	$(1,931)	$2,701	$—	$24,073
Real estate	32,721	2,882	(1,165)	795	—	35,233
Asset-backed securities	7,068	—	(2,085)	12	—	4,995
Mortgage-backed securities	66,321	16,782	(19,681)	535	—	63,957
Total	$129,413	$19,664	$(24,862)	$4,043	$—	$128,258

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3 [(a)]	Sept. 30, 2013
Private equity investments	$33,250	$15,344	$—	$3,880	$—	$52,474
Real estate	39,074	18,106	(9,022)	3,198	—	51,356
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	$104,600	$33,450	$(9,022)	$7,078	$(32,276)	$103,830

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements.

(Thousands of Dollars)	Jan. 1, 2012	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3	Sept. 30, 2012
Private equity investments	$9,203	$13,390	$(1,931)	$3,411	$—	$24,073
Real estate	26,395	6,789	(2,931)	4,980	—	35,233
Asset-backed securities	16,501	—	(11,544)	38	—	4,995
Mortgage-backed securities	78,664	31,100	(46,099)	292	—	63,957
Total	$130,763	$51,279	$(62,505)	$8,721	$—	$128,258

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Sept. 30, 2013:

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$—	$—	$28,946	$28,946
U.S. corporate bonds	306	21,488	64,953	1,814	88,561
International corporate bonds	—	4,506	11,470	—	15,976
Municipal bonds	3,118	23,549	26,922	144,328	197,917
Debt securities	$3,424	$49,543	$103,345	$175,088	$331,400

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Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Sept. 30, 2013, accumulated other comprehensive losses related to interest rate derivatives included $2.3 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for any unsettled hedges.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale and vehicle fuel.

At Sept. 30, 2013, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the three and nine months ended Sept. 30, 2013 and 2012.

At Sept. 30, 2013, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

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Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at Sept. 30, 2013 and Dec. 31, 2012:

(Amounts in Thousands) [a][b]	Sept. 30, 2013	Dec. 31, 2012
Megawatt hours (MWh) of electricity	69,682	55,976
Million British thermal units (MMBtu) of natural gas	11,752	725
Gallons of vehicle fuel	532	682

[a] Amounts are not reflective of net positions in the underlying commodities.
[b] Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy Inc. and its subsidiaries employ additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. At Sept. 30, 2013, four of Xcel Energy's 10 most significant counterparties for these activities, comprising $70.6 million or 23 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Five of the 10 most significant counterparties, comprising $89.4 million or 29 percent of this credit exposure at Sept. 30, 2013, were not rated by these agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising $9.4 million or 3 percent of this credit exposure at Sept. 30, 2013, had credit quality less than investment grade, based on Xcel Energy's internal analysis. All 10 of these significant counterparties are municipal or cooperative electric entities or other utilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income, is detailed in the following table:

	Three Months Ended Sept. 30	
(Thousands of Dollars)	2013	2012
Accumulated other comprehensive loss related to cash flow hedges at July 1	$(60,883)	$(55,710)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	22	(8,853)
After-tax net realized losses on derivative transactions reclassified into earnings	539	393
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$(60,322)	$(64,170)

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2013	2012

Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(61,241)	$(45,738)
After-tax net unrealized losses related to derivatives accounted for as hedges	(9)	(19,188)
After-tax net realized losses on derivative transactions reclassified into earnings	928	756
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$(60,322)	$(64,170)

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The following tables detail the impact of derivative activity during the three and nine months ended Sept. 30, 2013 and 2012, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and(Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$829 (a)	$ —	$—
Vehicle fuel and other commodity	36	—	(24) (b)	—	—
Total	$36	$—	$805	$ —	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$7,094 (c)
Electric commodity	—	921	—	(9,823) (d)	—
Natural gas commodity	—	(1,967)	—	—	12 (d)
Total	$—	$(1,046)	$—	$ (9,823)	$7,106

	Nine Months Ended Sept. 30, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$3,140 (a)	$—	$—
Vehicle fuel and other commodity	(11)	—	(67) (b)	—	—
Total	$(11)	$—	$3,073	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$9,372 (c)
Electric commodity	—	61,314	—	(38,816) (d)	—
Natural gas commodity	—	(5,341)	—	9 (e)	(216) (d)
Total	$—	$55,973	$—	$(38,807)	$9,156

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(Thousands of Dollars)	Three Months Ended Sept. 30, 2012 Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and(Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$(14,923)	$—	$733 [a]	$ —	$—
Vehicle fuel and other commodity	157	—	(44) [b]	—	—
Total	$(14,766)	$—	$689	$ —	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$7,651 [c]
Electric commodity	—	3,923	—	(11,931) [d]	—
Natural gas commodity	—	1,193	—	—	—
Total	$—	$5,116	$—	$ (11,931)	$7,651

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2012 Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$(31,914)	$—	$1,511 [a]	$—	$—
Vehicle fuel and other commodity	140	—	(145) [b]	—	—
Total	$(31,774)	$—	$1,366	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$10,963 [c]
Electric commodity	—	43,679	—	(29,616) [d]	—
Natural gas commodity	—	(8,705)	—	80,939 [e]	(109) [d]
Total	$—	$34,974	$—	$51,323	$10,854

[a] Amounts are recorded to interest charges.
[b] Amounts are recorded to O&M expenses.
[c]

Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts for the nine months ended Sept. 30, 2012 included $5.0 million of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such losses for the nine months ended Sept. 30, 2013 were immaterial. The remaining settlement losses for the nine months ended Sept. 30, 2013 and 2012 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2013 and 2012. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale (NPNS) contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. If the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade, derivative instruments reflected in a $2.7 million and $4.6 million gross liability position on the consolidated balance sheets at Sept. 30, 2013 and Dec. 31, 2012, respectively, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle outstanding contracts, including other contracts subject to master netting agreements, which would have resulted in payments of $2.7 million and $4.6 million at Sept. 30, 2013 and Dec. 31, 2012, respectively. At Sept. 30, 2013 and Dec. 31, 2012, there was no collateral posted on these specific contracts.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Sept. 30, 2013 and Dec. 31, 2012.

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Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Sept. 30, 2013:

	Sept. 30, 2013 Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$72	$—	$72	$—	$72
Other derivative instruments:						
Commodity trading	—	23,112	2,142	25,254	(8,490)	16,764
Electric commodity	—	—	41,052	41,052	(2,672)	38,380
Natural gas commodity	—	4,443	—	4,443	—	4,443
Total current derivative assets	$—	$27,627	$43,194	$70,821	$(11,162)	59,659
Purchased power agreements [a]						33,028
Current derivative instruments						$92,687
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$27	$—	$27	$(15)	$12
Other derivative instruments:						
Commodity trading	—	33,862	2,716	36,578	(7,306)	29,272
Total noncurrent derivative assets	$—	$33,889	$2,716	$36,605	$(7,321)	29,284
Purchased power agreements [a]						66,610
Noncurrent derivative instruments						$95,894
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$13,607	$1,770	$15,377	$(11,751)	$3,626
Electric commodity	—	—	2,672	2,672	(2,672)	—
Total current derivative liabilities	$—	$13,607	$4,442	$18,049	$(14,423)	3,626
Purchased power agreements [a]						23,103
Current derivative instruments						$26,729
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$14,767	$—	$14,767	$(7,321)	$7,446
Total noncurrent derivative liabilities	$—	$14,767	$—	$14,767	$(7,321)	7,446
Purchased power agreements [a]						209,581
Noncurrent derivative instruments						$217,027

[a] In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting

requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Sept. 30, 2013. At Sept. 30, 2013, derivative assets and liabilities include obligations to return cash collateral of $0.4 million and rights to reclaim cash collateral of $3.6 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2012:

	Dec. 31, 2012 Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$95	$—	$95	$—	$95
Other derivative instruments:						
Commodity trading	—	26,303	692	26,995	(6,675)	20,320
Electric commodity	—	—	16,724	16,724	(843)	15,881
Natural gas commodity	—	7	—	7	(7)	—
Total current derivative assets	$—	$26,405	$17,416	$43,821	$(7,525)	36,296
Purchased power agreements [a]						32,717
Current derivative instruments						$69,013
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$86	$—	$86	$(47)	$39
Other derivative instruments:						
Commodity trading	—	41,282	77	41,359	(4,162)	37,197
Total noncurrent derivative assets	$—	$41,368	$77	$41,445	$(4,209)	37,236
Purchased power agreements [a]						89,061
Noncurrent derivative instruments						$126,297
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$18,622	$1	$18,623	$(9,112)	$9,511
Electric commodity	—	—	843	843	(843)	—
Natural gas commodity	—	98	—	98	(7)	91
Total current derivative liabilities	$—	$18,720	$844	$19,564	$(9,962)	9,602
Purchased power agreements [a]						22,880
Current derivative instruments						$32,482
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$21,417	$—	$21,417	$(4,210)	$17,207
Total noncurrent derivative liabilities	$—	$21,417	$—	$21,417	$(4,210)	17,207
Purchased power agreements [a]						225,659
Noncurrent derivative instruments						$242,866

[a] In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting

requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2012. At Dec. 31, 2012, derivative assets and liabilities include obligations to return cash collateral of $0.6 million and rights to reclaim cash collateral of $3.0 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents the changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2013 and 2012:

	Three Months Ended Sept. 30	
(Thousands of Dollars)	2013	2012
Balance at July 1	$47,218	$33,789
Purchases	155	—
Settlements	(9,342)	(12,649)
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	4,008	13
(Losses) gains recognized as regulatory assets and liabilities	(571)	4,629
Balance at Sept. 30	$41,468	$25,782

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2013	2012
Balance at Jan. 1	$16,649	$12,417
Purchases	51,541	37,296
Settlements	(30,294)	(34,209)
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	3,729	5
(Losses) gains recognized as regulatory assets and liabilities	(157)	10,273
Balance at Sept. 30	$41,468	$25,782

[(a)] These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2013 and 2012.

Fair Value of Long-Term Debt

As of Sept. 30, 2013 and Dec. 31, 2012, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Sept. 30, 2013		Dec. 31, 2012	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$11,194,811	$12,007,389	$10,402,060	$12,207,866

The fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Sept. 30, 2013 and Dec. 31, 2012, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

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9. Other (Expense) Income, Net

Other (expense) income, net consisted of the following:

(Thousands of Dollars)	Three Months Ended Sept. 30 2013	Three Months Ended Sept. 30 2012	Nine Months Ended Sept. 30 2013	Nine Months Ended Sept. 30 2012
Interest income	$1,304	$1,820	$7,615	$8,323
Other nonoperating income	739	714	2,494	2,793
Insurance policy expense	(2,386)	(2,042)	(5,932)	(5,902)
Other nonoperating expense	(61)	(4)	(246)	(261)
Other (expense) income, net	$(404)	$488	$3,931	$4,953

10. Segment Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $87.8 million and $91.2 million as of Sept. 30, 2013 and Dec. 31, 2012, respectively, included in the regulated natural gas utility segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from continuing operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

(Thousands of Dollars)	All

	Regulated Electric	Regulated Natural Gas	Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2013					
Operating revenues from external customers	$2,599,925	$205,358	$17,055	$—	$2,822,338
Intersegment revenues	346	1,106	—	(1,452)	—
Total revenues	$2,600,271	$206,464	$17,055	$(1,452)	$2,822,338
Income (loss) from continuing operations	$365,156	$(174)	$(446)	$—	$364,536

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(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2012					
Operating revenues from external customers	$2,532,709	$174,513	$17,119	$—	$2,724,341
Intersegment revenues	287	461	—	(748)	—
Total revenues	$2,532,996	$174,974	$17,119	$(748)	$2,724,341
Income (loss) from continuing operations	$400,185	$4,296	$(6,334)	$—	$398,147

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2013					
Operating revenues from external customers	$6,911,998	$1,216,275	$55,827	$—	$8,184,100
Intersegment revenues	955	2,163	—	(3,118)	—
Total revenues	$6,912,953	$1,218,438	$55,827	$(3,118)	$8,184,100
Income (loss) from continuing operations	$740,347	$80,698	$(23,039)	$—	$798,006

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2012					
Operating revenues from external customers	$6,506,320	$1,016,861	$53,907	$—	$7,577,088
Intersegment revenues	886	1,179	—	(2,065)	—
Total revenues	$6,507,206	$1,018,040	$53,907	$(2,065)	$7,577,088
Income (loss) from continuing operations	$733,557	$60,688	$(29,254)	$—	$764,991

11. Earnings Per Share

Basic earnings per share (EPS) was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents), were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated based on the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards.

Share-Based Compensation

Common stock equivalents related to share-based compensation causing dilutive impact to EPS include commitments to issue common stock as an employer match to 401(k) plan participants. Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due to certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted, pending remaining service conditions.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Restricted stock unit equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Performance share plan liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

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The dilutive impact of common stock equivalents affecting EPS was as follows:

	Three Months Ended Sept. 30, 2013			Three Months Ended Sept. 30, 2012		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$364,752			$398,106		
Basic earnings per share:						
Earnings available to common shareholders	364,752	498,149	$0.73	398,106	488,084	$0.82
Effect of dilutive securities:						
401(k) equity awards	—	492		—	494	
Diluted earnings per share:						
Earnings available to common shareholders	$364,752	498,641	$0.73	$398,106	488,578	$0.81

	Nine Months Ended Sept. 30, 2013			Nine Months Ended Sept. 30, 2012		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$798,179			$765,059		
Basic earnings per share:						
Earnings available to common shareholders	798,179	495,256	$1.61	765,059	487,722	$1.57
Effect of dilutive securities:						
401(k) equity awards	—	511		—	476	
Diluted earnings per share:						
Earnings available to common shareholders	$798,179	495,767	$1.61	$765,059	488,198	$1.57

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended Sept. 30			
	2013	2012	2013	2012
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$24,071	$21,591	$1,182	$1,050
Interest cost	35,173	39,043	8,417	9,465
Expected return on plan assets	(49,613)	(51,774)	(8,253)	(7,102)
Amortization of transition obligation	—	—	206	3,580
Amortization of prior service cost (credit)	1,468	5,266	(2,438)	(1,888)
Amortization of net loss	36,038	26,893	5,646	4,228
Net periodic benefit cost	47,137	41,019	4,760	9,333
Costs not recognized and additional cost recognized due to the effects of regulation	(12,986)	(9,645)	—	972
Net benefit cost recognized for financial reporting	$34,151	$31,374	$4,760	$10,305

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(Thousands of Dollars)	Nine Months Ended Sept. 30 2013 Pension Benefits	2012	2013 Postretirement Health Care Benefits	2012
Service cost	$72,212	$64,773	$3,546	$3,152
Interest cost	105,518	117,131	25,251	28,396
Expected return on plan assets	(148,839)	(155,322)	(24,759)	(21,307)
Amortization of transition obligation	—	—	618	10,740
Amortization of prior service cost (credit)	4,404	15,799	(7,314)	(5,664)
Amortization of net loss	108,114	80,678	16,938	12,680
Net periodic benefit cost	141,409	123,059	14,280	27,997
Costs not recognized and additional cost recognized due to the effects of regulation	(27,922)	(28,936)	—	2,918
Net benefit cost recognized for financial reporting	$113,487	$94,123	$14,280	$30,915

In 2013, contributions of $192.2 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2013.

13. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the three and nine months ended Sept. 30, 2013 were as follows:

(Thousands of Dollars)	Three Months Ended Sept. 30, 2013 Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at July 1	$(60,883)	$(135)	$(50,817)	$(111,835)
Other comprehensive gain before reclassifications	22	115	—	137
Losses reclassified from net accumulated other comprehensive loss	539	—	1,179	1,718
Net current period other comprehensive income	561	115	1,179	1,855
Accumulated other comprehensive loss at Sept. 30	$(60,322)	$(20)	$(49,638)	$(109,980)

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2013 Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(61,241)	$(99)	$(51,313)	$(112,653)
Other comprehensive gain (loss) before reclassifications	(9)	79	—	70
Losses reclassified from net accumulated other comprehensive loss	928	—	1,675	2,603
Net current period other comprehensive income	919	79	1,675	2,673
Accumulated other comprehensive loss at Sept. 30	$(60,322)	$(20)	$(49,638)	$(109,980)

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Reclassifications from accumulated other comprehensive loss for the three and nine months ended Sept. 30, 2013 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended Sept. 30, 2013	Nine Months Ended Sept. 30, 2013
(Gains) losses on cash flow hedges:		
Interest rate derivatives	$829 [a]	$3,140 [a]
Vehicle fuel derivatives	(24) [b]	(67) [b]
Total, pre-tax	805	3,073
Tax benefit	(266)	(2,145)
Total, net of tax	539	928
Defined benefit pension and postretirement losses:		
Amortization of net loss	1,770 [c]	5,308 [c]
Prior service cost	93 [c]	279 [c]
Transition obligation	2 [c]	6 [c]
Total, pre-tax	1,865	5,593
Tax benefit	(686)	(3,918)
Total, net of tax	1,179	1,675
Total amounts reclassified, net of tax	$1,718	$2,603

[a] Included in interest charges.

[b] Included in O&M expenses.

[c] Included in the computation of net periodic pension and post retirement benefit costs. See Note 12 for details regarding these benefit plans.

Item 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements. Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

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Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 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,” “objecti “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 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 NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Continuing Operations in Item 7 of Xcel Energy Inc.’s Form 10-K for the year ended Dec. 31, 2012; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including “Risk Factors” in Item 1A of Xcel Energy Inc.’s Form 10-K for the year ended Dec. 31, 2012, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2013.

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy’s financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements.

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The earnings and ongoing diluted EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS 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. Xcel Energy’s management uses this non-GAAP financial measure to evaluate and provide details of earnings results. Xcel Energy’s management believes 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 Xcel Energy’s consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

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Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	2013	2012	2013	2012
PSCo	$0.33	$0.36	$0.77	$0.75
NSP-Minnesota	0.31	0.28	0.67	0.57
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	0.81	0.81	1.77	1.64
Xcel Energy Inc. and other costs	(0.04)	(0.03)	(0.12)	(0.10)
Ongoing diluted earnings per share	0.77	0.78	1.65	1.54
SPS 2004 FERC complaint case orders	(0.04)	—	(0.04)	—
Prescription drug tax benefit	—	0.03	—	0.03
GAAP diluted earnings per share	$0.73	$0.81	$1.61	$1.57

Ongoing earnings exclude adjustments for certain items. For 2013, the adjustment is related to the SPS 2004 FERC complaint case orders. For 2012, the adjustment is related to the Patient Protection and Affordable Care Act. See below under Adjustments to GAAP Earnings and Note 5 to the consolidated financial statements for further discussion.

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.

Adjustments to GAAP Earnings

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 to the consolidated financial statements for further discussion.

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.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Xcel Energy — Overall, ongoing earnings decreased $0.01 per share for the third quarter of 2013. Ongoing earnings, 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.

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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 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.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2013 diluted EPS compared with the same period in 2012. See further discussion below.

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	(0.03)	(0.03)
2012 ongoing 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)	—	0.15
Higher natural gas margins	0.01	0.07
Lower interest charges (excludes impact of SPS 2004 FERC complaint case orders)	0.02	0.04
Higher Allowance for Funds Used During Construction (AFUDC) — equity	0.01	0.04
Lower ETR	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 diluted earnings per share	0.77	1.65
SPS 2004 FERC complaint case orders	(0.04)	(0.04)
2013 GAAP diluted earnings per share	$0.73	$1.61

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The following tables summarize the earnings contributions of Xcel Energy's business segments:

(Millions of Dollars)	Three Months Ended Sept. 30 2013	Three Months Ended Sept. 30 2012	Nine Months Ended Sept. 30 2013	Nine Months Ended Sept. 30 2012
GAAP income (loss) by segment				
Regulated electric income	$365.2	$400.2	$740.3	$733.6
Regulated natural gas income	—	4.3	80.7	60.7
Other income [a]	17.9	8.8	35.4	20.0
Segment income — continuing operations	383.1	413.3	856.4	814.3
Xcel Energy Inc. and other costs [a]	(18.3)	(15.2)	(58.2)	(49.3)
Total income — continuing operations	364.8	398.1	798.2	765.0
Income from discontinued operations	—	—	—	0.1
Total GAAP net income	$364.8	$398.1	$798.2	$765.1

Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30 2013	Three Months Ended Sept. 30 2012	Nine Months Ended Sept. 30 2013	Nine Months Ended Sept. 30 2012
GAAP earnings (loss) by segment				
Regulated electric	$0.73	$0.82	$1.50	$1.50
Regulated natural gas	—	0.01	0.16	0.13
Other [a]	0.04	0.01	0.07	0.04
Segment earnings per share — continuing operations	0.77	0.84	1.73	1.67
Xcel Energy Inc. and other costs [a]	(0.04)	(0.03)	(0.12)	(0.10)
Total earnings per share — continuing operations	0.73	0.81	1.61	1.57
Discontinued operations	—	—	—	—
Total GAAP earnings per diluted share	$0.73	$0.81	$1.61	$1.57

[a] Not a reportable segment. Included in all other segment results in Note 10 to the consolidated financial statements.

Statement of Income Analysis

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

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.

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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 Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have little impact on electric margin. The following table details the electric revenues and margin:

	Three Months Ended 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

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The following tables summarize the components of the changes in electric revenues and electric margin:

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2013 vs. 2012	Nine Months Ended Sept. 30 2013 vs. 2012
Fuel and purchased power cost recovery	$78	$284
Retail rate increases [a]	46	177
Transmission revenue	20	57
Non-fuel riders	7	10
Firm wholesale	(10)	(29)
Conservation and demand side management (DSM) program incentives	(17)	(26)
PSCo earnings test refund obligation	(11)	(20)
SPS 2004 FERC complaint case orders [b]	(5)	(5)
Estimated impact of weather	(20)	(1)
Other, net	5	(15)
Total increase in ongoing electric revenues	93	432
SPS 2004 FERC complaint case orders [b]	(26)	(26)
Total increase in GAAP electric revenues	$67	$406

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 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 5 to the consolidated financial statements for further discussion.

(b) As a result of two orders issued by the 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 to the consolidated financial statements for further discussion.

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Natural Gas Revenues and Margin

The cost of natural gas tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	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 tables summarize the components of the changes in natural gas revenues and natural gas margin:

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2013 vs. 2012	Nine Months Ended Sept. 30 2013 vs. 2012
Purchased natural gas adjustment clause recovery	$27	$148
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	(4)	(2)
Total increase in natural gas revenues	$30	$199

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

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Non-Fuel Operating Expenses and Other Items

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.

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 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 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.

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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.

Public Utility Regulation

NSP-Minnesota

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 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 the system – including the replacement of the steam generator at Prairie Island; the life extension at the nuclear plants, the return to service of 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 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. Hearings were held in October 2013. The competitive acquisition schedule is expected to be as follows:

- 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 (MISO);
- 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.

In September 2013, the Minnesota Center for Environmental Advocacy filed a motion with the MPUC asking that a new proceeding be undertaken to update and expand Minnesota's environmental externality values. The motion is currently pending the MPUC's action.

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CapX2020 Transmission Expansion — In 2009, the MPUC approved separate CON applications to construct one 230 kilovolt (kV) electric transmission line and three 345 kV electric transmission lines as part of the CapX2020 project. The estimated cost of the four transmission projects is $1.9 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total cost. The remainder of the costs will be borne by other utilities in the upper Midwest. These cost estimates will be updated as the projects progress.

Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 345 kV transmission line
In May 2012, the MPUC issued a route permit for the Minnesota portion of the project and the PSCW approved a CPCN for the Wisconsin portion of the project. Federal approval of the project was granted in January 2013. All avenues of appeal for the grant of project permits have now been exhausted. In July 2013, the FERC denied a complaint filed by two citizen groups in March 2013 against the project. Construction on the project started in Minnesota in January 2013 and the project is expected to go into service in 2015.

Minnesota Solar Legislation — In May 2013, Minnesota's Governor signed into law legislation requiring that 1.5 percent of a public utility's total electric retail sales to retail customers, net of customer exclusions, be generated using solar energy by 2020. Of the 1.5 percent, 10 percent must come from systems sized less than 20 kilowatts. The legislation also authorized NSP-Minnesota to offer two new solar programs: a community solar garden program that will provide bill credits to participating solar garden subscribers and a new solar energy incentive program for solar energy systems equal to or less than 20 kilowatts that authorizes the spending of five million dollars over five years for production incentive payments. NSP-Minnesota submitted its proposal for a community solar garden program to the MPUC on Sept. 30, 2013. Under the terms of the solar legislation, the MPUC may approve, disapprove or modify the program. NSP-Minnesota is currently developing the new solar energy incentive program. The legislation also provides for an alternative tariff based on a distributed solar value or "Value of Solar" methodology. The legislation requires the Department of Commerce (DOC) to develop and file with the MPUC a distributed solar value methodology by Jan. 31, 2014. The MPUC must approve, modify with the consent of the DOC or disapprove the methodology within 60 days. Once the methodology is approved, NSP-Minnesota may file a "Value of Solar" tariff. The DOC is conducting a series of workshops in 2013 to develop the "Value of Solar" methodology. NSP-Minnesota provided comments to the DOC on the methodology of this "Value of Solar" alternative tariff on Oct. 1 and Oct. 8, 2013.

Minnesota Interim Ratemaking Ruling — In September 2013, the Minnesota Supreme Court issued its decision affirming the MPUC's decision regarding Minnesota Power's 2011 interim rate request. The MPUC reduced Minnesota Power's interim rate request by 60 percent due to the existence of the following exigent circumstances: (1) timing of the case (filed within one day of receiving a final order in its prior case), (2) size of the case, and (3) the state of the economy. In affirming the decision, the Minnesota Supreme Court found that the MPUC did not exceed its statutory authority in finding exigent circumstances, and that the MPUC findings were supported by substantial evidence. This ruling clarifies the MPUC's authority when establishing interim rates.

Annual Automatic Adjustment (AAA) of Charges — As part of the 2012 AAA dockets in June 2013, the DOC included a fuel clause incentive proposal that would normalize Fuel Clause Adjustment (FCA) recovery using monthly patterns derived from averages of the prior three year period, setting and fixing this level during a rate case with no adjustment between rate cases. NSP-Minnesota filed reply comments opposing the DOC's proposal in August 2013 including a demonstration of the random and volatile results the DOC's fuel clause incentive proposal would have had if it were in place during the 2008-2012 period. Other utilities filed reply comments in September 2013 expressing similar concern with the DOC's incentive proposal, further indicating no support for modification to operation of the fuel clause. Subsequently, the DOC requested the MPUC convene a stakeholder meeting to discuss general purpose and function of the FCA program. On Oct. 24, 2013, the MPUC allowed the DOC opportunity to discuss current challenges in evaluating the prudence of fuel clause costs. The 2012 AAA docket is pending.

Additionally, the DOC has indicated it will review prudence of replacement power costs associated with the Sherco Unit 3 outage event within the 2013 AAA docket.

Minneapolis, Minn. Franchise Agreement — In August 2013, the Minneapolis City Council elected not to conduct a special election on Nov. 5, 2013 to pursue forming a municipal utility. The Minneapolis City Council has commissioned a study to explore the various paths the City of Minneapolis could take to achieve its energy goals, including examination of potential utility partnerships, changes to how the City of Minneapolis uses energy utility franchise fees and the potential for municipalization of one or both energy utilities. Results of the study are due in the first quarter of 2014. The franchise agreement with the City of Minneapolis expires Dec. 31, 2014.

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Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See Note 14 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2012 for further discussion regarding the nuclear generating plants.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants. The event at the nuclear generating plant in Fukushima, Japan in 2011 could impact the NRC's deliberations on NSP-Minnesota's Monticello power uprate request and could also result in additional regulation, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force that has developed recommendations on whether it should require immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures and licensing processes. In July 2011, the task force released its recommendations in a written report which recommends actions to enhance U.S. nuclear generating plant readiness to safely manage severe events.

In March 2012, the NRC issued three orders. The orders included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The NRC also requested additional information including requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards and to assess the emergency preparedness staffing and communications capabilities at each plant. Based on current refueling outage plans specific to each nuclear facility, the dates of the required compliance to meet the orders is expected to begin in the second quarter of 2015 with all units expected to be fully compliant by December 2016.

In June 2013, the NRC issued a revised order with regard to reliable hardened containment vents. The revised order added severe accident conditions under which the existing hardened vent which comes off of the wet portion of the containment needs to operate and requires a second hardened vent off of the dry portion of the containment. The revised order requires that any necessary changes to the existing vent are to be completed by the second quarter of 2017 refueling outage at the Monticello plant and a new vent to be added by the second quarter of 2019 refueling outage. Portions of the work that fall under the requests for additional information are expected to be completed by 2018.

NSP-Minnesota expects that complying with these requirements will cost approximately $40 to $60 million at the Monticello and Prairie Island plants. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

Nuclear Plant EPU

Monticello Nuclear Plant EPU — In 2008, NSP-Minnesota filed for both state and federal regulatory approvals of an EPU of approximately 71 MW for NSP-Minnesota's Monticello nuclear generating plant. For state resource planning purposes, the MPUC approved the CON for the EPU in 2008. Federal regulatory proceedings were delayed by concerns raised by the NRC's Advisory Committee on Reactor Safeguards (ACRS) related to containment pressure associated with pump performance. In September 2012, NSP-Minnesota made a supplemental filing to the NRC to address the containment accident pressure concern. In September 2013, the ACRS met with NSP-Minnesota officials and determined the issue was resolved, recommending to the NRC that the EPU license be approved. The NRC is expected to meet on this issue in November 2013, and could approve the EPU license for the Monticello plant at that time. However, the federal government budget shutdown in October 2013 could delay this timing.

In July 2013, NSP-Minnesota completed implementation of the equipment changes needed to support the Monticello 20-year life extension and EPU projects during the plant's 2013 refueling outage. However, the plant will not be permitted to operate at the higher uprate capacity levels without NRC license approval. The Monticello plant will commence ascension to higher power levels as soon as the NRC EPU license is received. A second NRC license is also needed to proceed to full uprate capacity, for final approval of fuel configuration and utilization under full uprate conditions. NSP-Minnesota expects to receive approval of the second EPU license by the NRC in the first half of 2014 pending any impacts from the federal government shutdown in the fall of 2013. The method and timing of rate recovery of the costs associated with the Monticello life extension and EPU construction projects was included as part of the 2013 electric rate case, and will again be addressed in the 2014 rate case currently planned to be filed in early November 2013. The project costs will be subject to a prudence review by the MPUC coincident with the 2014 electric rate case. See Note 5 to the consolidated financial statements for further discussion. The prudence filing was submitted to the MPUC on Oct. 18, 2013.

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The EPU project was completed concurrently with LCM work at Monticello to support the 20-year extension of the operating license for the plant. A preliminary cost estimate provided to the MPUC in 2008 as part of the EPU CON filing was $320 million, including both LCM and EPU work. Final costs of the project after completion of the 2013 refueling outage were approximately $665 million, but could be reduced depending on the results of ongoing vendor cost negotiations. The primary reasons for the increased cost estimates of Monticello's LCM/EPU project include (a) outside events have affected the NRC's schedule and requirements, adding time and cost to the project; (b) our original estimate was based on preliminary engineering and a conceptual framework before any detailed work activities were scoped; and (c) we discovered additional work was necessary once our planned work entered the construction phase during the 2011 and 2013 refueling outages.

PSCo

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.

Boulder, Colo. Municipalization Exploration — PSCo's franchise agreement with the City of Boulder expired on Dec. 31, 2010. In November 2010, the citizens of Boulder voted to impose an occupational tax to replace franchise fee revenues that would terminate when the franchise agreement terminated. In November 2011, two ballot measures were passed by the citizens of Boulder. The first measure increased the occupation tax to raise an additional $1.9 million annually for funding the exploration costs of forming a municipal utility and acquiring the PSCo electric distribution system in Boulder. The second measure authorized the formation and operation of a municipal light and power utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage.

Boulder Staff have performed a feasibility study on municipalization and in July 2013, recommended that Boulder create its own electric utility. A Task Force of Boulder citizens met with PSCo and City representatives from April through July and recommended continued discussions between Boulder and Xcel Energy. In August 2013, the Boulder City Council voted to authorize the acquisition of PSCo’s transmission and distribution system in and near Boulder on or after Jan. 1, 2014. The City Council also directed City Staff to continue discussions with PSCo through the citizen Task Force on PSCo proposals to meet the City’s energy future goals.

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Boulder's feasibility study 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 has petitioned the CPUC for a declaratory ruling that Boulder cannot serve PSCo's customers outside Boulder's city limits without obtaining a CPCN from the CPUC. In oral deliberations on Oct. 9, 2013, the CPUC declared that the CPUC 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. A written order is expected in the fourth quarter of 2013.

Boulder filed a petition with the FERC for a declaratory ruling that if Boulder enters into a partial requirements wholesale contract with PSCo, no stranded costs associated with the MW supplied under the partial requirements contract would be owed by Boulder. In July 2013, the FERC denied Boulder's petition, without prejudice.

There are two measures on the November ballot that could affect Boulder's municipalization options. A citizen petitioned measure would require, among other things, voter approval of the total debt issued by Boulder in connection with its municipal utility. A City Council referred measure would limit facility acquisition cost to $214 million.

PSCo would seek to obtain full compensation for the property, and in this case, the business taken by Boulder as well as for all damages resulting to PSCo and its system, and should Boulder attempt to condemn PSCo facilities PSCo would also seek appropriate compensation for stranded costs with the FERC.

SPS

PPA Approvals — On July 10, 2013, SPS filed with the NMPRC for authorization to enter into three PPAs for approximately 700 MW of wind power. These contracts were entered into by SPS for economic purposes, not to meet the state mandated renewable energy portfolios. A decision is expected from the NMPRC prior to the end of 2013.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2012. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

MISO Transmission Pricing — The MISO Tariff presently provides for different allocation methods for the costs of new transmission investments depending on whether the project is primarily local or regional in nature. If a project qualifies as a multi-value project (MVP), the costs would be fully allocated to all loads in the MISO region. MVP eligibility is generally obtained for higher voltage (345 kV and higher) projects considered part of a portfolio of projects expected to serve multiple purposes, such as improved reliability, reduced congestion, transmission for renewable energy, and load serving. Certain parties appealed the FERC MVP tariff orders to the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit). In June 2013, the Seventh Circuit upheld the FERC MVP tariff orders allocating MVP project costs regionally, but remanded the FERC decision to not apply the regional charge to transmission service transactions crossing into the PJM Interconnection, LLC Regional Transmission Organization (RTO). U.S. Supreme Court review of the Seventh Circuit decision has been requested; the U.S. Supreme Court's response is pending. The NSP System has certain new transmission facilities for which other customers in MISO contribute to cost recovery. Likewise, the NSP System also pays a share of the costs of projects constructed by other transmission owning entities. The transmission revenues received by the NSP System from MISO, and the transmission charges paid to MISO, associated with projects subject to regional cost allocation could be significant in future periods.

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FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — The FERC issued Order 1000 in July 2011 adopting new requirements for transmission planning, cost allocation and development to be effective prospectively. In Order 1000, the FERC required utilities to develop tariffs that provide for joint regional transmission planning and cost allocation for all FERC-jurisdictional utilities within a region. In addition, Order 1000 required that regions coordinate to develop interregional plans for transmission planning and cost allocation. A key provision of Order 1000 is a requirement that FERC-jurisdictional wholesale transmission tariffs exclude provisions that would grant the incumbent transmission owner a federal Right of First Refusal (ROFR) to build certain types of transmission projects in its service area. Various parties have appealed Order 1000 final rules to the D.C. Circuit Court of Appeals. NSP-Minnesota and NSP-Wisconsin are participating in the appeals in coordination with other MISO transmission owners and utilities who oppose certain aspects of the rules, including the ROFR prohibition. Initial briefs by parties challenging the final rules were filed in May 2013. The FERC submitted its responsive brief on Sept. 25, 2013. Reply briefs from all parties are due on Nov. 15, 2013. Oral arguments have not yet been scheduled. The Court is unlikely to rule before 2014.

The removal of a federal ROFR will eliminate rights that NSP-Minnesota, NSP-Wisconsin, and SPS currently have under the MISO and Southwest Power Pool, Inc. (SPP) tariffs to build certain transmission projects within their footprints. Rather, the FERC required that the opportunity to build such projects would extend to competitive transmission developers. Compliance with Order 1000 for NSP-Minnesota and NSP-Wisconsin will occur through changes to the MISO tariff while compliance for SPS will occur through the SPP tariff. PSCo is not in an RTO and therefore is responsible for making its own Order 1000 compliance filing. MISO, SPP, and PSCo all made their initial compliance filings to incorporate new provisions into their tariffs regarding regional planning and cost allocation. The FERC has ruled on the regional compliance filings for MISO, SPP and PSCo, directing further changes to fully address the requirements of Order 1000.

Filings to address interregional planning and cost allocation requirements with other regions were made by PSCo, MISO and SPP in May or July 2013. The filings are pending action by the FERC. In addition, SPP and MISO received an extension of the deadline for filing their interregional planning and cost allocation agreement with the Midcontinent Area Power Pool which will likely delay that filing until late third quarter of 2014.

NSP-System

In 2012, Minnesota enacted legislation that preserves ROFR rights for Minnesota utilities at the state level. This legislation is similar to legislation previously passed in North Dakota and South Dakota. Wisconsin has not developed such legislation. The FERC's initial order on MISO's compliance filing to address the regional requirements of Order 1000 required MISO to remove proposed tariff provisions that would have recognized state ROFR rights and allowed state regulators to select the developer of a transmission project and Xcel Energy has requested rehearing of this issue. The rehearing request is pending the FERC's action. In a filing concurrent to MISO's Order 1000 compliance filing, the FERC accepted changes to MISO's transmission cost allocation procedures that will protect the ROFR for projects needed for system reliability.

PSCo

Colorado does not have legislation protecting ROFR rights for incumbent utilities. PSCo submitted its compliance filing to address the regional planning and cost allocation requirements of Order 1000, proposing that PSCo would join the WestConnect region, a consortium of utilities in the Western Interconnection. In March 2013, the FERC issued its initial order on PSCo's compliance filing and required a number of changes. In April 2013, PSCo and other WestConnect members requested rehearing on various aspects of the March 2013 order. While requests for rehearing of the March 2013 order are pending, PSCo and other WestConnect jurisdictional utilities made their compliance filings on Sept. 20, 2013 to address directives in the March 2013 order. The FERC is expected to rule in late 2013 or early 2014 on the compliance filing and the requests for rehearing that were filed. The WestConnect members filed the interregional compliance filing in May 2013 and action on that filing is pending.

SPS

The FERC issued its initial order on SPP's Order 1000 regional compliance filing in July 2013. In the order, the FERC identified several areas that will require a further compliance filing by SPP to address regional compliance issues identified by the FERC. Among other things, the FERC rejected SPP's proposal to retain a ROFR for new transmission projects with operational voltages between 100 kV and 300 kV. Requests for rehearing of the FERC's July 2013 order were filed Aug. 19, 2013 and are pending the FERC's action. The further SPP regional compliance filing is due Nov. 15, 2013. The SPP interregional compliance filing was submitted in July 2013 and is pending the FERC's action. With respect to ROFR rights of incumbent utilities, Xcel Energy believes that Texas statutes protect the right of incumbent utilities operating outside of the Electric Reliability Council of Texas to construct and own transmission interconnected to their systems, though this view is disputed by some parties. The State of New Mexico does not have legislation protecting ROFR rights for incumbent utilities.

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Environmental, Legal and Other Matters

See a discussion of environmental, legal and other matters in Note 6 to the consolidated financial statements.

Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported even if the nature of the accounting policies applied have not changed. Item 7 — Management's Discussion and Analysis, in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2012, includes a discussion of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and that require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. As of Sept. 30, 2013, there have been no material changes to policies set forth in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2012.

Pending Accounting Changes

See a discussion of recently issued accounting pronouncements and pending accounting changes in Note 2 to the consolidated financial statements.

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 8 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and non-performance risk.

Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

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At Sept. 30, 2013, the fair values by source for net commodity trading contract assets were as follows:

Futures / Forwards

(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$9,031	$17,949	$2,556	$271	$29,807
NSP-Minnesota	2	172	—	—	1,009	1,181
PSCo	1	474	—	—	—	474
		$9,677	$17,949	$2,556	$1,280	$31,462

Options

(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	2	$200	$26	$—	$—	$226

1 — Prices actively quoted or based on actively quoted prices.
2 — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms were as follows:

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2013	2012
Fair value of commodity trading net contract assets outstanding at Jan. 1	$28,314	$20,424
Contracts realized or settled during the period	(6,018)	(9,778)
Commodity trading contract additions and changes during period	9,392	17,244
Fair value of commodity trading net contract assets outstanding at June 30	$31,688	$27,890

At Sept. 30, 2013, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.4 million. At Sept. 30, 2012, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.5 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.5 million.

Xcel Energy Inc.'s utility subsidiaries' wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Three Months Ended Sept. 30	VaR Limit	Average	High	Low
2013	$0.48	$3.00	$0.45	$1.35	$0.18
2012	0.46	3.00	0.51	1.21	0.19

Interest Rate Risk — Xcel Energy is subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Sept. 30, 2013 and 2012, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $4.4 million and $4.2 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

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Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Sept. 30, 2013, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $37.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $12.7 million. At Sept. 30, 2012, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $10.7 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $13.7 million.

Xcel Energy Inc. and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 8 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Sept. 30, 2013. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as other comprehensive income or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Sept. 30, 2013.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 2.8 percent and 40.1 percent of total assets and liabilities, respectively, measured at fair value at Sept. 30, 2013.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $45.9 million and $4.4 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2013.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. Level 3 commodity derivative assets and liabilities included $2.7 million of forwards and no options at Sept. 30, 2013.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of private equity investments and real estate investments. Based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling $103.8 million in the nuclear decommissioning fund at Sept. 30, 2013 (approximately 6.3 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

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Liquidity and Capital Resources

Cash Flows

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2013	2012
Cash provided by operating activities	$2,003	$1,572

Net cash provided by operating activities increased $431 million for the nine months ended Sept. 30, 2013, compared with the nine months ended Sept. 30, 2012. The increase was the result of higher net income, changes in working capital related to the timing of payments and receipts and 2012 interest rate swap settlements, partially offset by increased purchases of natural gas.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2013	2012
Cash used in investing activities	$(2,311)	$(1,610)

Net cash used in investing activities increased $701 million for the nine months ended Sept. 30, 2013, compared with the nine months ended Sept. 30, 2012. The increase was the result of higher capital expenditures related to nuclear, transmission and CACJA projects, as well as the change in restricted cash associated with the 2012 nuclear waste disposal settlement.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2013	2012
Cash provided by financing activities	$327	$724

Net cash provided by financing activities decreased $397 million for the nine months ended Sept. 30, 2013, compared with the nine months ended Sept. 30, 2012. The decrease was primarily due to higher repayments of previously existing short term debt and lower proceeds from the issuances of long-term debt, partially offset by proceeds from issuances of common stock.

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the Commodity Futures Trading Commission (CFTC) and the SEC with expanded regulatory authority over derivative and swap transactions. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements.

As a result of this legislation there will be material increased reporting requirements for certain volumes of derivative and swap activity. In April 2012, the CFTC ruled that swap dealing activity conducted by entities under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the de minimis exemption level and will not subject an entity to registering as a swap dealer. Xcel Energy's current and projected swap activity is below this de minimis level. The CFTC has set an $800 million de minimis volume exemption for swaps with "Utility Special Entities," defined by the CFTC as primarily entities owning or operating electric or natural gas facilities and government entities, after which the entity would have to register as a swap dealer. The bill also contains provisions that should exempt certain derivatives end users from much of the clearing and margin requirements. Xcel Energy does not expect to be materially impacted by the margining provisions. Xcel

Energy has completed its review of the additional reporting obligations for “trade options,” which are physical electric and gas contracts that contain embedded volumetric and/or price optionality. At this time, none of the contracts reviewed qualify as a “trade option.” However, this determination is subject to change as additional Dodd-Frank Act rules are finalized and subsequent transactions are executed. Xcel Energy is currently meeting all other reporting requirements.

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Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income securities, and alternative investments, including private equity, real estate, hedge fund and commodity investments.

- In 2013, contributions of $192.2 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2013;
- In 2012, contributions of $198.1 million were made across four of Xcel Energy's pension plans; and
- For future years, we anticipate contributions will be made as necessary.

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Sept. 30, 2013, approximately $4.3 million of cash was held in these accounts.

Commercial Paper — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $800 million for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $300 million for SPS; and
- $150 million for NSP-Wisconsin.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2013		Twelve Months Ended Dec. 31, 2012	
Borrowing limit	$2,450		$2,450	
Amount outstanding at period end	302		602	
Average amount outstanding	347		403	
Maximum amount outstanding	491		634	
Weighted average interest rate, computed on a daily basis	0.27	%	0.35	%
Weighted average interest rate at period end	0.25		0.36	

Credit Facilities — As of Oct. 22, 2013, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$800.0	$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.

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Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

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.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

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.

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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.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis under Item 2.

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Sept. 30, 2013, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting.

Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters.

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Additional Information

See Note 6 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Note 5 to the consolidated financial statements for discussion of proceedings involving utility rates and other regulatory matters.

Item 1A — RISK FACTORS

Xcel Energy Inc.'s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2012, which is incorporated herein by reference.

Item 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended Sept. 30, 2013:

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2013 — July 31, 2013	—	—	—	—
Aug. 1, 2013 — Aug. 31, 2013	—	—	—	—
Sept. 1, 2013 — Sept. 30, 2013	—	—	—	—
Total	—		—	—

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

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Item 6 — EXHIBITS

* Indicates incorporation by reference
+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2013 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Oct. 25, 2013

By: /s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Vice President and Controller
(Principal Accounting Officer)

/s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)