XCEL ENERGY INC
Form 10-Q
August 02, 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 June 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 July 26, 2013
Common Stock, $2.50 par value	497,570,936 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 June 30		Six Months Ended June 30	
	2013	2012	2013	2012
Operating revenues				
Electric	$2,219,877	$2,036,829	$4,312,073	$3,973,611
Natural gas	341,321	221,313	1,010,917	842,348
Other	17,715	16,526	38,772	36,788
Total operating revenues	2,578,913	2,274,668	5,361,762	4,852,747
Operating expenses				
Electric fuel and purchased power	1,011,044	854,373	1,936,087	1,718,353
Cost of natural gas sold and transported	188,765	89,759	628,140	507,705
Cost of sales — other	7,881	5,944	16,292	13,248
Operating and maintenance expenses	562,557	534,014	1,091,788	1,044,698
Conservation and demand side management program expenses	60,445	58,615	124,477	122,322
Depreciation and amortization	243,934	226,641	492,640	455,313
Taxes (other than income taxes)	102,051	99,632	215,478	205,256
Total operating expenses	2,176,677	1,868,978	4,504,902	4,066,895
Operating income	402,236	405,690	856,860	785,852
Other income, net	413	728	4,335	4,465
Equity earnings of unconsolidated subsidiaries	7,529	7,502	15,106	14,660
Allowance for funds used during construction — equity	22,109	15,194	41,863	28,644
Interest charges and financing costs				
Interest charges — includes other financing costs of $12,229, $6,036, $18,038 and $12,116, respectively	146,828	151,921	286,441	303,751
Allowance for funds used during construction — debt	(10,316)	(7,683)	(19,074)	(14,290)
Total interest charges and financing costs	136,512	144,238	267,367	289,461
Income from continuing operations before income taxes	295,775	284,876	650,797	544,160
Income taxes	98,893	101,801	217,327	177,316
Income from continuing operations	196,882	183,075	433,470	366,844
(Loss) income from discontinued operations, net of tax	(25)	(15)	(43)	109
Net income	$196,857	$183,060	$433,427	$366,953
Weighted average common shares outstanding:				
Basic	497,747	487,717	493,786	487,538
Diluted	498,036	488,017	494,303	488,006
Earnings per average common share:				

Basic	$0.40	$0.38	$0.88	$0.75
Diluted	0.40	0.38	0.88	0.75
Cash dividends declared per common share	$0.28	$0.27	$0.55	$0.53

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 June 30		Six Months Ended June 30	
	2013	2012	2013	2012
Net income	$196,857	$183,060	$433,427	$366,953
Other comprehensive income (loss)				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $729, $647, $3,232 and $1,269, respectively	1,135	932	496	1,827
Derivative instruments:				
Net fair value decrease, net of tax of $(29), $(23,164), $(17) and $(6,673), respectively	(44)	(35,727)	(31)	(10,335)
Reclassification of losses to net income, net of tax of $451, $158, $1,881 and $314, respectively	694	182	389	363
	650	(35,545)	358	(9,972)
Marketable securities:				
Net fair value increase (decrease), net of tax of $0, $83, $(18) and $119, respectively	—	122	(36)	174
Other comprehensive income (loss)	1,785	(34,491)	818	(7,971)
Comprehensive income	$198,642	$148,569	$434,245	$358,982

See Notes to Consolidated Financial Statements

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

	Six Months Ended June 30	
	2013	2012
Operating activities		
Net income	$433,427	$366,953
Remove loss (income) from discontinued operations	43	(109)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	507,658	464,117
Conservation and demand side management program amortization	3,425	3,765
Nuclear fuel amortization	49,485	49,765
Deferred income taxes	235,684	278,358
Amortization of investment tax credits	(3,314)	(3,104)
Allowance for equity funds used during construction	(41,863)	(28,644)
Equity earnings of unconsolidated subsidiaries	(15,106)	(14,660)
Dividends from unconsolidated subsidiaries	18,683	8,028
Share-based compensation expense	18,747	17,249
Net realized and unrealized hedging and derivative transactions	(2,754)	7,325
Changes in operating assets and liabilities:		
Accounts receivable	(78,940)	(928)
Accrued unbilled revenues	37,069	139,012
Inventories	40,684	145,095
Other current assets	29,700	(61,291)
Accounts payable	1,625	(177,076)
Net regulatory assets and liabilities	76,693	12,912
Other current liabilities	(83,336)	(117,653)
Pension and other employee benefit obligations	(170,162)	(168,898)
Change in other noncurrent assets	16,940	(40,893)
Change in other noncurrent liabilities	(163)	(14,027)
Net cash provided by operating activities	1,074,225	865,296
Investing activities		
Utility capital/construction expenditures	(1,596,778)	(1,103,562)
Proceeds from insurance recoveries	50,000	24,000
Allowance for equity funds used during construction	41,863	28,644
Purchases of investments in external decommissioning fund	(890,700)	(371,361)
Proceeds from the sale of investments in external decommissioning fund	887,500	371,361
Investment in WYCO Development LLC	(2,166)	(379)
Change in restricted cash	—	94,959
Other, net	(1,696)	(24)
Net cash used in investing activities	(1,511,977)	(956,362)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(248,000)	262,000
Proceeds from issuance of long-term debt	1,337,045	111,015

Repayments of long-term debt, including reacquisition premiums	(651,516)	(2,455)
Proceeds from issuance of common stock	227,113	3,698
Repurchase of common stock	—	(18,529)
Purchase of common stock for settlement of equity awards	—	(23,307)
Dividends paid	(250,392)	(238,510)
Net cash provided by financing activities	414,250	93,912
Net change in cash and cash equivalents	(23,502)	2,846
Cash and cash equivalents at beginning of period	82,323	60,684
Cash and cash equivalents at end of period	$58,821	$63,530
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(258,124)	$(281,266)
Cash received (paid) for income taxes, net	13,681	(5,875)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$302,434	$274,350
Issuance of common stock for reinvested dividends and 401(k) plans	37,504	35,543

See Notes to Consolidated Financial Statements

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

	June 30, 2013	Dec. 31, 2012
Assets		
Current assets		
Cash and cash equivalents	$58,821	$82,323
Accounts receivable, net	719,069	718,046
Accrued unbilled revenues	626,294	663,363
Inventories	494,890	535,574
Regulatory assets	396,308	352,977
Derivative instruments	100,215	69,013
Deferred income taxes	158,350	32,528
Prepayments and other	264,253	171,315
Total current assets	2,818,200	2,625,139
Property, plant and equipment, net	24,813,411	23,809,348
Other assets		
Nuclear decommissioning fund and other investments	1,622,978	1,617,865
Regulatory assets	2,727,210	2,762,029
Derivative instruments	100,313	126,297
Other	184,150	200,008
Total other assets	4,634,651	4,706,199
Total assets	$32,266,262	$31,140,686
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$282,042	$258,155
Short-term debt	354,000	602,000
Accounts payable	998,607	959,093
Regulatory liabilities	205,112	168,858
Taxes accrued	242,339	334,441
Accrued interest	156,751	162,494
Dividends payable	139,240	131,748
Derivative instruments	29,897	32,482
Other	288,822	287,802
Total current liabilities	2,696,810	2,937,073
Deferred credits and other liabilities		
Deferred income taxes	4,820,650	4,434,909
Deferred investment tax credits	80,587	82,761
Regulatory liabilities	1,070,059	1,059,939
Asset retirement obligations	1,762,959	1,719,796
Derivative instruments	222,575	242,866
Customer advances	261,684	252,888
Pension and employee benefit obligations	988,773	1,163,265
Other	245,443	229,207
Total deferred credits and other liabilities	9,452,730	9,185,631

Commitments and contingencies		
Capitalization		
Long-term debt	10,816,477	10,143,905
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 497,295,719 and 487,959,516 shares outstanding at June 30, 2013 and Dec. 31, 2012, respectively	1,243,239	1,219,899
Additional paid in capital	5,595,906	5,353,015
Retained earnings	2,572,935	2,413,816
Accumulated other comprehensive loss	(111,835)	(112,653)
Total common stockholders' equity	9,300,245	8,874,077
Total liabilities and equity	$32,266,262	$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 June 30, 2013 and 2012						
Balance at March 31, 2012	486,936	$1,217,339	$5,298,572	$2,089,275	$(67,515)	$8,537,671
Net income				183,060		183,060
Other comprehensive loss					(34,491)	(34,491)
Dividends declared:						
Common stock				(131,696)		(131,696)
Issuances of common stock	350	875	8,482			9,357
Share-based compensation			9,604			9,604
Balance at June 30, 2012	487,286	$1,218,214	$5,316,658	$2,140,639	$(102,006)	$8,573,505
Balance at March 31, 2013	494,755	$1,236,888	$5,515,513	$2,516,332	$(113,620)	$9,155,113
Net income				196,857		196,857
Other comprehensive income					1,785	1,785
Dividends declared:						
Common stock				(140,254)		(140,254)
Issuances of common stock	2,541	6,351	67,940			74,291
Share-based compensation			12,453			12,453
Balance at June 30, 2013	497,296	$1,243,239	$5,595,906	$2,572,935	$(111,835)	$9,300,245

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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
Six Months Ended June 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				366,953		366,953
Other comprehensive loss					(7,971)	(7,971)
Dividends declared:						
Common stock				(258,870)		(258,870)
Issuances of common stock	1,492	3,730	10,770			14,500
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			18,531			18,531
Balance at June 30, 2012	487,286	$1,218,214	$5,316,658	$2,140,639	$(102,006)	$8,573,505
Balance at Dec. 31, 2012	487,960	$1,219,899	$5,353,015	$2,413,816	$(112,653)	$8,874,077
Net income				433,427		433,427
Other comprehensive income					818	818
Dividends declared:						
Common stock				(274,308)		(274,308)
Issuances of common stock	9,336	23,340	219,785			243,125
Share-based compensation			23,106			23,106
Balance at June 30, 2013	497,296	$1,243,239	$5,595,906	$2,572,935	$(111,835)	$9,300,245

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 June 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 six months ended June 30, 2013 and 2012; and its cash flows for the six months ended June 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 June 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.

3. Selected Balance Sheet Data

(Thousands of Dollars)	June 30, 2013	Dec. 31, 2012
Accounts receivable, net		
Accounts receivable	$766,848	$769,440
Less allowance for bad debts	(47,779)	(51,394)
	$719,069	$718,046

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(Thousands of Dollars)	June 30, 2013	Dec. 31, 2012
Inventories		
Materials and supplies	$222,628	$213,739
Fuel	186,009	189,425
Natural gas	86,253	132,410
	$494,890	$535,574

(Thousands of Dollars)	June 30, 2013	Dec. 31, 2012
Property, plant and equipment, net		
Electric plant	$29,017,319	$28,285,031
Natural gas plant	3,903,127	3,836,335
Common and other property	1,475,534	1,480,558
Plant to be retired [a]	115,466	152,730
Construction work in progress	2,298,899	1,757,189
Total property, plant and equipment	36,810,345	35,511,843
Less accumulated depreciation	(12,344,995)	(12,048,697)
Nuclear fuel	2,142,145	2,090,801
Less accumulated amortization	(1,794,084)	(1,744,599)
	$24,813,411	$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 June 30, 2013, the IRS had not proposed any material adjustments to tax years 2010 and 2011.

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 June 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	2008
Wisconsin	2008

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 June 30, 2013, no material adjustments had been proposed for either of these audits. There are currently no other state income tax audits in progress.

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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)	June 30, 2013	Dec. 31, 2012
Unrecognized tax benefit — Permanent tax positions	$7.6	$4.7
Unrecognized tax benefit — Temporary tax positions	31.7	29.8
Total unrecognized tax benefit	$39.3	$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)	June 30, 2013	Dec. 31, 2012
NOL and tax credit carryforwards	$(38.1)	$(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 June 30, 2013 and Dec. 31, 2012 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 2013 or Dec. 31, 2012.

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 Report on Form 10-Q for the quarter period ended March 31, 2013, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

Pending Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

Base Rate

NSP-Minnesota – Minnesota 2012 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 is based on a 2013 forecast test year, a requested return on equity (ROE) of 10.6 percent, an average electric rate base of approximately $6.3 billion and an equity ratio of 52.56 percent. In January 2013, interim rates of approximately $251 million became effective, subject to refund.

In March 2013, NSP-Minnesota filed rebuttal testimony and revised the requested annual revenue increase to approximately $219.7 million, or 8.23 percent, based on an ROE of 10.6 percent, a rate base of approximately $6.3 billion and an equity ratio of 52.56 percent. The updated request reflects alternate proposals in several key areas including:

- Deferral of depreciation expenses and property taxes related to Sherco Unit 3 for 2012 and 2013 and removal of avoided 2013 operating and maintenance (O&M) expense due to the extended outage at Sherco Unit 3.
- Removal of Monticello 2013 license costs from plant in service and deferral of 2013 depreciation expense for the primary Monticello life cycle management (LCM) / extended power uprate (EPU) project until after an MPUC order finding the costs prudent.
- Removal of Prairie Island EPU project costs, reflecting the MPUC decision to cancel the project in December 2012.

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- Adjustments to compensation and benefits recovery including Annual Incentive Plan (AIP) to reflect prior MPUC decisions establishing a limitation at 15 percent of base pay using a four-year average AIP target, pension expense and active healthcare costs.
- Adjustment of pension recoveries to reflect amortized recovery of 2008 market losses.
- Recovery of coal pile and ash pond remediation costs at the Black Dog plant through a 15 year amortization.
- Updated forecast for property taxes.
- Updated forecast with 6 months of actual sales, customer and weather data through December 2012, and updated economic assumptions based on a December 2012 economic forecast, proposing a refund if sales are higher than forecast on a weather-normalized basis.
- Correction to the original filing and other adjustments.

In April 2013, intervenors filed surrebuttal testimony, including the Minnesota Department of Commerce (DOC), Office of Attorney General (OAG), Minnesota Chamber (MCC), Xcel Large Industrials (XLI), Commercial Group, Industrial, Commercial and Institutional Customers, and Energy Cents Coalition. The DOC recommended a revenue increase of $89.6 million, based on a 9.83 percent ROE, an average electric rate base of approximately $6.1 billion and an equity ratio of 52.56 percent. Subsequently, the DOC’s recommendation was revised to approximately $98.6 million, largely to reflect updated information.

In its surrebuttal testimony, the OAG recommended no recovery for the Prairie Island EPU project, stating it should have been written off in 2012 when cancellation of the project was approved by the MPUC. The DOC is also not supportive of recovery of the Prairie Island EPU cancelled EPU costs. The OAG suggests pension recovery in rates exceeds benefit payout because of changes made to benefit plans and recommends correction for an alleged over-collection of funds to pay for future benefits which may never be paid out. The OAG supports the DOC in adjustments to recovery of annual incentive compensation and does not find NSP-Minnesota’s Sherco Unit 3 proposal warranted. XLI and MCC also opposed recovery of Sherco Unit 3 costs and Monticello EPU costs.

Through the hearing and briefing process, NSP-Minnesota revised its rate request to approximately $209 million to reflect updated property tax information, resolution of concerns regarding Wisconsin wholesale customers and other adjustments. The $209 million revenue requirement reflects a requested deficiency of $259 million combined with $50 million of rate mitigation through deferral mechanisms.

ALJ Recommendation

On July 3, 2013, the Minnesota Administrative Law Judge (ALJ) issued her report and recommended a rate increase of approximately $127 million, based on a ROE of 9.83 percent, an equity ratio of 52.56 percent and an electric rate base of $6.233 billion. In addition, the ALJ recommendation included approximately $51 million in deferrals of which NSP-Minnesota estimates $34 million will affect net income. The deferrals are related to Sherco Unit 3 and pension.

The ALJ indicated that Sherco Unit 3 should be considered “used and useful” for rate making purposes, but that a portion of the Monticello LCM/EPU would not be considered “used and useful” until NSP-Minnesota obtains the uprate license from the Nuclear Regulatory Commission (NRC). The ALJ also found that the prudency of the cost increases for the Monticello LCM/EPU project and cost recovery for the cancelled Prairie Island EPU project should be determined in the next Minnesota rate case. In addition, the ALJ recommended accepting NSP-Minnesota’s position on the inclusion of the pension market loss and incentive compensation and the DOC’s position on the sales forecast.

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The table below reconciles the final position of NSP-Minnesota, the DOC and the ALJ.

(Millions of Dollars)	NSP-Minnesota Request	DOC Recommendation	ALJ Recommendation
NSP-Minnesota original request	$285	$285	$285
ROE	—	(43)	(43)
Sherco Unit 3	(35)	(40)	(38)
Reduced recovery for the nuclear plants	(11)	(9)	(14)
Incentive compensation	(3)	(20)	(4)
Sales forecast	(1)	(26)	(26)
Pension	(10)	(25)	(13)
Employee benefits	(4)	(6)	(6)
Black Dog remediation	(5)	(5)	(5)
NSP-Wisconsin wholesale allocation	(7)	(7)	(7)
Other, net	—	(5)	(2)
Recommended rate increase	209	99	127
Preliminary estimated impact of cost deferrals	50	5	34
Estimated impact on 2013 pre-tax income	$259	$104	$161

The MPUC has scheduled deliberations for Aug. 6 and 8, 2013. The MPUC is expected to reach a decision on the issues at the deliberations and issue an order in September 2013.

NSP-Minnesota recorded a current regulatory liability representing the current best estimate of a refund obligation associated with the interim rates of approximately $16 million and $47 million, as of March 31 and June 30, 2013, respectively.

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

Base Rate

NSP-Minnesota – North Dakota 2012 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 forecast test year, 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. There were no intervenors in this proceeding.

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On July 17, 2013, NDPSC Advocacy Staff filed direct testimony prepared by their rate case consultants. Staff's testimony recommended a 9.0 percent ROE and other revenue requirement adjustments, which resulted in an overall rate reduction of approximately $2.1 million. Primary revenue requirement adjustments include:

(Millions of Dollars)	Revenue requirement adjustments as filed by the Staff
NSP-Minnesota revised request	$16.0
Use of a one month coincident peak demand allocator for certain rate base and operation expenses	(20.0)
ROE	(5.2)
Incentive compensation	(0.8)
Adjustment for various O&M expenses	(0.7)
Calculation of federal income taxes	6.3
Modified cost of capital and increased capital structure to 53.42 percent	1.4
Other, net	0.9
Recommended rate decrease	$(2.1)

Additionally, NDPSC Staff recommends customers in NSP-Minnesota's North Dakota jurisdiction be excluded from paying for costs of certain purchased power agreements.

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

- Rebuttal Testimony – Aug. 12, 2013
- Technical Hearings – Aug. 27-28, 2013
- Initial Briefs – Sept. 20, 2013
- Reply Briefs/Proposed Findings – October 2013

A final NDPSC decision on the case is expected in the fourth quarter of 2013.

NSP-Wisconsin

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

Base Rate

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 forecast test year, a 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.

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

- Staff and Intervenor Direct Testimony – Oct. 4, 2013

- Rebuttal Testimony – Oct. 18, 2013
- Surrebuttal testimony – Oct. 28, 2013
- Hearing – Oct. 30, 2013
- Initial Brief – Nov. 13, 2013
- 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

Base Rate

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 forecast test year, 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.

In order to accommodate the procedural schedule, rates will go into effect as filed on Aug. 10, 2013, subject to refund.

On April 3, 2013, four parties filed answer testimony in the natural gas case. The CPUC Staff and Office of Consumer Counsel (OCC) recommended changes to the level of integrity management costs moved from the PSIA rider to base rates. PSCo's 2013 deficiency based on a Forecasted Test Year (FTY) net of PSIA changes was $45 million for 2013 and the revenue deficiency was $28.3 million based on a Historic Test Year (HTY).

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

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

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

On April 29, 2013, PSCo filed rebuttal testimony and revised its requested annual rate increase to $44.8 million for 2013, with subsequent step increases of $9.0 million for 2014 and $10.9 million for 2015, based on an ROE of 10.3 percent. PSCo agreed to recover approximately $3.5 million of revenue requirement in the PSIA, rather than through base rates and accepted the CPUC Staff's recommendation to use deferred accounting to accommodate property tax increases.

Hearings were held in May 2013. An ALJ recommendation is anticipated in August 2013 and a decision is expected in the third quarter of 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 forecast test year, a 10.5 percent ROE, a rate base of $21 million for steam and an equity ratio of 56 percent. Final rates are expected to be effective in the fourth quarter of 2013.

On July 23, 2013, PSCo, CPUC Staff, the OCC and Colorado Energy Consumers representing the Building Owners Management Association filed an unopposed joint motion for the CPUC to vacate the current procedural schedule and to set a date of Aug. 12, 2013, by which the parties shall file either: (i) a comprehensive settlement agreement resolving all issues presented in this matter; or (ii) a consensus revised procedural schedule.

PSCo – 2011 Electric Rate Case Earnings Test — On April 1, 2013, PSCo filed a tariff implementing the earnings sharing mechanism consistent with the settlement and CPUC decision for PSCo's 2011 electric rate case. The 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 the April 2013 filing for 2012, PSCo indicated that its earnings did not exceed the established threshold. CPUC Staff, the OCC and Colorado Energy Consumers each filed notices with the CPUC disputing PSCo's assertion that earnings did not exceed the threshold. In June 2013, PSCo entered into a comprehensive settlement of issues with all parties, which was approved by the CPUC and resulted in a refund of approximately $8.2 million to customers over the next year. As of June 30, 2013, PSCo recognized a liability for the settlement amount as well as an estimated accrual representing its best estimate of any refund obligation for the 2013 test year.

Electric, Purchased Gas and Resource Adjustment Clauses

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 beginning in 2011 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 June 30, 2013 and 2012, PSCo credited the RESA regulatory asset balance $6.5 million and $6.3 million, respectively. The cumulative credit to the RESA regulatory asset balance was $93.3 million and $82.8 million at June 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 to provide the CPUC an opportunity to review the framework and evidence regarding actual deliveries.

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. A procedural schedule has not been set.

SPS

Pending Regulatory Proceedings — Public Utility Commission of Texas (PUCT)

Base Rate

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.

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In April 2013, the parties filed a settlement agreement in which SPS' base rate will increase by $37 million, effective May 1, 2013, on an interim basis pending the PUCT's approval of the settlement, 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. On June 6, 2013, the PUCT approved the settlement without modification.

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

Base Rate

SPS – New Mexico 2012 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. The rate filing is based on a 2014 forecast test year, a requested ROE of 10.65 percent, a jurisdictional electric rate base of $479.8 million and an equity ratio of 53.89 percent.

In March 2013, the NMPRC ruled that SPS' case, as originally filed, was incomplete due to confidential exhibits to testimony and schedules being included in SPS' direct case, and directed the hearing examiner to review SPS' claims of confidentiality and to determine the date the filing is complete. After SPS made filings to address the NMPRC's concern about the confidential documents, the hearing examiner determined that SPS' application was completed on April 12, 2013. The NMPRC has suspended the tariffs for an initial nine month period beyond that date, or until Jan. 11, 2014. The NMPRC has authority to suspend the rates for an additional three months beyond the initial nine month period, or until April 11, 2014. On June 19, 2013, SPS revised its requested rate increase to $43.3 million.

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

- Staff/Intervenor Direct Testimony – Aug. 22, 2013
- Rebuttal Testimony – Sept. 9, 2013
- Evidentiary Hearings – Sept. 16-27, 2013

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 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 Federal Energy Regulatory Commission (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.

Next steps in the procedural schedules are expected to be as follows:

- PUCT Intervenor Direct Testimony – Aug. 2, 2013
- PUCT Staff Direct Testimony – Aug. 9, 2013
- PUCT SPS Rebuttal Testimony – Aug. 16, 2013
- PUCT Evidentiary Hearing – Sept. 3, 2013
- NMPRC Staff/Intervenor Direct Testimony – Sept. 12, 2013
- NMPRC SPS Rebuttal Testimony – Sept. 27, 2013
- NMPRC Evidentiary Hearing – Oct. 8 - 9, 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.

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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.

The Xcel Energy utility subsidiaries had approximately 3,406 megawatts (MW) and 3,324 MW of capacity under long-term purchased power agreements as of June 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 June 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)	June 30, 2013	Dec. 31, 2012
Guarantees issued and outstanding	$54.8	$69.5
Current exposure under these guarantees	17.9	17.9
Bonds with indemnity protection	31.0	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 in 2013.

Negotiations between the EPA and NSP-Wisconsin regarding who will pay or perform the cleanup of the Sediments are ongoing. 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 scheduled for June 2014. 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 June 30, 2013 and Dec. 31, 2012, NSP-Wisconsin had recorded a liability of $101.3 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 $14.3 million and $20.1 million, respectively, was considered a current liability. The reduction in recorded liability at June 30, 2013 reflects that cleanup has now commenced and costs are being incurred with respect to the Phase I Project Area. 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 a recent rate case decision, the PSCW recognized the potential magnitude of the future liability for the cleanup at the Ashland site. In December 2012, the PSCW 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.

Environmental Requirements

Greenhouse Gas (GHG) New Source Performance Standard Proposal (NSPS) and Emission Guideline for Existing Sources — In April 2012, the EPA proposed a GHG NSPS for newly constructed power plants. The proposal requires that carbon dioxide (CO_2) emission rates be equal to a natural gas combined-cycle plant, even if the plant is coal-fired. The EPA also proposed that NSPS not apply to modified or reconstructed existing power plants and that installation of control equipment on existing plants would not constitute a “modification” to those plants under the NSPS program. On June 25, 2013, President Obama issued a memorandum directing the EPA to re-propose GHG emission standards for new power plants and develop GHG emission standards for existing power plants. It is not possible to evaluate the impact of these regulations until the upcoming proposals and final requirements are known.

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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. Although the D.C. Circuit had denied all requests for rehearing, 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 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 2017. 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 June 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 (CCR). 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. The EPA is also seeking comment on the interaction between the ELG proposal and its proposed CCR rule, which is another proposed rule that would also regulate surface impoundments that store coal combustion byproducts (coal ash) and whether to regulate coal ash as hazardous or nonhazardous waste. A final rule is anticipated in 2014. Under the current proposed rule, facilities would need to comply as soon as possible after July 1, 2017 but no later than July 1, 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.

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 $340.8 million. PSCo expects the cost of any required capital investment will be recoverable from customers.

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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.

The estimated cost for meeting the BART, regional haze and other CAA requirements is approximately $50 million, of which $34 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.

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.

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New Mexico GHG Regulations — In 2010, the New Mexico Environmental Improvement Board (EIB) adopted two regulations to limit GHG emissions, including CO_2 emissions from power plants and other industrial sources. The EIB repealed both regulations in the first quarter of 2012. Western Resource Advocates and New Energy Economy, Inc. filed appeals with the New Mexico Court of Appeals to challenge each of the EIB's decisions to repeal the two GHG rules. After the appellants filed unopposed motions to dismiss, the court dismissed these appeals in July 2013.

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

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in the U.S. District Court for the Northern District of California against Xcel Energy and 23 other utility, oil, gas and coal companies. Plaintiffs claim that defendants' emission of CO_2 and other greenhouse gases contribute to global warming, which is harming their village. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss in June 2008. In October 2009, the U.S. District Court dismissed the lawsuit on constitutional grounds. In November 2009, plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). In October 2012, the Ninth Circuit affirmed the U.S. District Court's dismissal and subsequently rejected plaintiffs' request for rehearing. In May 2013 the U.S. Supreme Court denied plaintiffs' request for review, which brings this litigation to a close. No accrual has been recorded for this matter.

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. It is uncertain whether plaintiffs will seek further review of this decision. Although Xcel Energy believes the likelihood of loss is remote based upon existing case law, 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.

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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. On Oct. 22, 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. On April 23, 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 Administrative Law Judge (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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On April 5, 2013, the FERC issued an order on rehearing of its remand order issued for the October 2011 review proceedings. 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 scheduled to begin in August 2013.

Preliminary calculations of the City of Seattle's claim for refunds from PSCo are approximately $28 million not including 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 third claim submission, in the amount of $42.8 million, was filed May 15, 2013 for costs incurred in 2012. The DOE has until Sept. 1, 2013 to accept or deny the claim, in whole or in part. Amounts received from the first installments were subsequently credited to customers, except for approved reductions such as legal costs, customer credit amounts still in process at June 30, 2013, 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 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 June 30, 2013		Twelve Months Ended Dec. 31, 2012	
Borrowing limit	$2,450		$2,450	
Amount outstanding at period end	354		602	
Average amount outstanding	255		403	
Maximum amount outstanding	487		634	
Weighted average interest rate, computed on a daily basis	0.29	%	0.35	%
Weighted average interest rate at period end	0.27		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 June 30, 2013 and Dec. 31, 2012, there were $15.7 million and $14.2 million of letters of credit outstanding, respectively, under the credit facilities. All letters of credit outstanding were issued under the credit facilities at June 30, 2013 and Dec. 31, 2012. 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 June 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	$278.0	$522.0
PSCo	700.0	4.6	695.4
NSP-Minnesota	500.0	36.1	463.9
SPS	300.0	49.0	251.0
NSP-Wisconsin	150.0	2.0	148.0
Total	$2,450.0	$369.7	$2,080.3

[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 June 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.

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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. As of June 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 the 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. 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; 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.

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.

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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 $169.6 million and $135.8 million at June 30, 2013 and Dec. 31, 2012, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $81.6 million and $46.4 million at June 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 June 30, 2013 and Dec. 31, 2012:

	June 30, 2013				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$32,663	$32,663	$—	$—	$32,663
Commingled funds	415,197	—	414,899	—	414,899
International equity funds	66,452	—	65,606	—	65,606
Private equity investments	36,496	—	—	45,590	45,590
Real estate	30,357	—	—	38,140	38,140
Debt securities:					
Government securities	56,017	—	49,702	—	49,702
U.S. corporate bonds	131,917	—	134,571	—	134,571
International corporate bonds	18,859	—	18,703	—	18,703
Municipal bonds	190,353	—	182,225	—	182,225
Equity securities:					
Common stock	429,086	513,339	—	—	513,339
Total	$1,407,397	$546,002	$865,706	$83,730	$1,495,438

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $88.7 million of equity investments in unconsolidated subsidiaries and $38.8 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 six months ended June 30, 2013 and 2012:

(Thousands of Dollars)	April 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3	June 30, 2013
Private equity investments	$34,506	$7,298	$—	$3,786	$—	$45,590
Real estate	40,406	2,032	(4,723)	425	—	38,140
Total	$74,912	$9,330	$(4,723)	$4,211	$—	$83,730

(Thousands of Dollars)	April 1, 2012	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	Transfers Out of Level 3	June 30, 2012
Private equity investments	$20,068	$3,235	$—	$—	$—	$23,303
Real estate	27,905	2,271	—	2,545	—	32,721
Asset-backed securities	16,547	—	(9,458)	(21)	—	7,068
Mortgage-backed securities	68,671	7,414	(9,690)	(74)	—	66,321
Total	$133,191	$12,920	$(19,148)	$2,450	$—	$129,413

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3 (a)	June 30, 2013
Private equity investments	$33,250	$8,554	$—	$3,786	$—	$45,590
Real estate	39,074	6,818	(9,022)	1,270	—	38,140
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	$104,600	$15,372	$(9,022)	$5,056	$(32,276)	$83,730

(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 (Losses) Recognized as Regulatory Assets and Liabilities	Transfers Out of Level 3	June 30, 2012
Private equity investments	$9,203	$13,390	$—	$710	$—	$23,303
Real estate	26,395	3,907	(1,766)	4,185	—	32,721
Asset-backed securities	16,501	—	(9,459)	26	—	7,068
Mortgage-backed securities	78,664	14,318	(26,418)	(243)	—	66,321

Total	$130,763	$31,615	$(37,643)	$4,678	$—	$129,413

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

(Thousands of Dollars)	Final Contractual Maturity 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	$—	$2,793	$11,211	$35,698	$49,702
U.S. corporate bonds	1,734	39,998	81,716	11,123	134,571
International corporate bonds	—	3,115	14,588	1,000	18,703
Municipal bonds	3,790	24,313	26,270	127,852	182,225
Debt securities	$5,524	$70,219	$133,785	$175,673	$385,201

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 June 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 June 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 six months ended June 30, 2013 and 2012.

At June 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 June 30, 2013 and Dec. 31, 2012:

(Amounts in Thousands) [a][b]	June 30, 2013	Dec. 31, 2012
Megawatt hours (MWh) of electricity	79,276	55,976
Million British thermal units (MMBtu) of natural gas	4,843	725
Gallons of vehicle fuel	582	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 June 30, 2013, five of Xcel Energy's 10 most significant counterparties for these activities, comprising $81.6 million or 28 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Four of the 10 most significant counterparties, comprising $55.6 million or 19 percent of this credit exposure at June 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 $7.9 million or 3 percent of this credit exposure at June 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, and no single counterparty comprised greater than 10 percent of Xcel Energy's credit exposure at June 30, 2013.

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 June 30	
(Thousands of Dollars)	2013	2012
Accumulated other comprehensive loss related to cash flow hedges at April 1	$(61,533)	$(20,165)
After-tax net unrealized losses related to derivatives accounted for as hedges	(44)	(35,727)
After-tax net realized losses on derivative transactions reclassified into earnings	694	182
Accumulated other comprehensive loss related to cash flow hedges at June 30	$(60,883)	$(55,710)

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(Thousands of Dollars)	Six Months Ended June 30 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	(31)	(10,335)
After-tax net realized losses on derivative transactions reclassified into earnings	389	363
Accumulated other comprehensive loss related to cash flow hedges at June 30	$(60,883)	$(55,710)

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

	Three Months Ended June 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 Losses Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$1,162 (a)	$ —	$—
Vehicle fuel and other commodity	(73)	—	(17) (b)	—	—
Total	$(73)	$—	$1,145	$ —	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$(498) (c)
Electric commodity	—	53,974	—	(13,764) (d)	—
Natural gas commodity	—	(3,427)	—	—	(244) (d)
Total	$—	$50,547	$—	$ (13,764)	$(742)

	Six Months Ended June 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	$—	$—	$2,312 (a)	$—	$—
Vehicle fuel and other commodity	(48)	—	(42) (b)	—	—
Total	$(48)	$—	$2,270	$—	$—

Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$2,278 (c)
Electric commodity	—	60,393	—	(28,993) (d)	—
Natural gas commodity	—	(3,374)	—	9 (e)	(228) (d)
Total	$—	$57,019	$—	$(28,984)	$2,050

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(Thousands of Dollars)	Three Months Ended June 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	$(58,695)	$—	$389 [a]	$ —	$—
Vehicle fuel and other commodity	(196)	—	(49) [b]	—	—
Total	$(58,891)	$—	$340	$ —	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$1,589 [c]
Electric commodity	—	38,174	—	(9,713) [d]	—
Natural gas commodity	—	885	—	—	—
Total	$—	$39,059	$—	$ (9,713)	$1,589

(Thousands of Dollars)	Six Months Ended June 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	$(16,991)	$—	$777 [a]	$—	$—
Vehicle fuel and other commodity	(17)	—	(100) [b]	—	—
Total	$(17,008)	$—	$677	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$3,312 [c]
Electric commodity	—	39,756	—	(17,685) [d]	—
Natural gas commodity	—	(9,898)	—	80,939 [e]	(109) [d]
Total	$—	$29,858	$—	$63,254	$3,203

[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 six months ended June 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 six months ended June 30, 2013 were immaterial. The remaining settlement losses for the six months ended June 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 six months ended June 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 $23.3 million and $4.6 million gross liability position on the consolidated balance sheets at June 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 $3.8 million and $4.6 million at June 30, 2013 and Dec. 31, 2012, respectively. At June 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 June 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 June 30, 2013:

	June 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	$—	$61	$—	$61	$—	$61
Other derivative instruments:						
Commodity trading	—	23,508	2,349	25,857	(8,008)	17,849
Electric commodity	—	—	50,105	50,105	(2,823)	47,282
Natural gas commodity	—	1,999	—	1,999	(2)	1,997
Total current derivative assets	$—	$25,568	$52,454	$78,022	$(10,833)	67,189
Purchased power agreements [a]						33,026
Current derivative instruments						$100,215
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$26	$—	$26	$(14)	$12
Other derivative instruments:						
Commodity trading	—	28,867	55	28,922	(3,410)	25,512
Total noncurrent derivative assets	$—	$28,893	$55	$28,948	$(3,424)	25,524
Purchased power agreements [a]						74,789
Noncurrent derivative instruments						$100,313
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$15,116	$2,468	$17,584	$(11,060)	$6,524
Electric commodity	—	—	2,823	2,823	(2,823)	—
Natural gas commodity	—	231	—	231	(2)	229
Total current derivative liabilities	$—	$15,347	$5,291	$20,638	$(13,885)	6,753
Purchased power agreements [a]						23,144
Current derivative instruments						$29,897
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$10,741	$—	$10,741	$(3,424)	$7,317
Total noncurrent derivative liabilities	$—	$10,741	$—	$10,741	$(3,424)	7,317
Purchased power agreements [a]						215,258
Noncurrent derivative instruments						$222,575

(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 June 30, 2013. 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. 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 six months ended June 30, 2013 and 2012:

	Three Months Ended June 30	
(Thousands of Dollars)	2013	2012
Balance at April 1	$7,642	$5,324
Purchases	51,386	37,296
Settlements	(8,503)	(12,675)
Net transactions recorded during the period:		
Losses recognized in earnings [a]	(217)	—
(Losses) gains recognized as regulatory assets and liabilities	(3,090)	3,844
Balance at June 30	$47,218	$33,789

	Six Months Ended June 30	
(Thousands of Dollars)	2013	2012
Balance at Jan. 1	$16,649	$12,417
Purchases	51,386	37,297
Settlements	(20,952)	(21,560)
Net transactions recorded during the period:		
Losses recognized in earnings [a]	(279)	(9)
Gains recognized as regulatory liabilities	414	5,644
Balance at June 30	$47,218	$33,789

[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 the three and six months ended June 30, 2013 and 2012.

Fair Value of Long-Term Debt

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

	June 30, 2013		Dec. 31, 2012	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$11,098,519	$11,996,501	$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 June 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 Income, Net

Other income, net consisted of the following:

	Three Months Ended June 30		Six Months Ended June 30	
(Thousands of Dollars)	2013	2012	2013	2012
Interest income	$1,505	$881	$6,311	$6,503
Other nonoperating income	534	1,157	1,755	2,079
Insurance policy expense	(1,407)	(1,061)	(3,546)	(3,860)
Other nonoperating expense	(219)	(249)	(185)	(257)
Other income, net	$413	$728	$4,335	$4,465

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 $88.7 million and $91.2 million as of June 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 June 30, 2013					
Operating revenues	$2,219,877	$341,321	$17,715	$—	$2,578,913
Intersegment revenues	308	557	—	(865)	—
Total revenues	$2,220,185	$341,878	$17,715	$(865)	$2,578,913
Income (loss) from continuing operations	$201,084	$15,960	$(20,162)	$—	$196,882

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(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2012					
Operating revenues	$2,036,829	$221,313	$16,526	$—	$2,274,668
Intersegment revenues	297	219	—	(516)	—
Total revenues	$2,037,126	$221,532	$16,526	$(516)	$2,274,668
Income (loss) from continuing operations	$190,151	$6,190	$(13,266)	$—	$183,075

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2013					
Operating revenues	$4,312,073	$1,010,917	$38,772	$—	$5,361,762
Intersegment revenues	609	1,057	—	(1,666)	—
Total revenues	$4,312,682	$1,011,974	$38,772	$(1,666)	$5,361,762
Income (loss) from continuing operations	$375,190	$80,870	$(22,590)	$—	$433,470

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2012					
Operating revenues	$3,973,611	$842,348	$36,788	$—	$4,852,747
Intersegment revenues	599	718	—	(1,317)	—
Total revenues	$3,974,210	$843,066	$36,788	$(1,317)	$4,852,747
Income (loss) from continuing operations	$333,372	$56,392	$(22,920)	$—	$366,844

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 June 30, 2013			Three Months Ended June 30, 2012		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$196,857			$183,060		
Basic earnings per share:						
Earnings available to common shareholders	196,857	497,747	$0.40	183,060	487,717	$0.38
Effect of dilutive securities:						
401(k) equity awards	-	289		-	300	
Diluted earnings per share:						
Earnings available to common shareholders	$196,857	498,036	$0.40	$183,060	488,017	$0.38

	Six Months Ended June 30, 2013			Six Months Ended June 30, 2012		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$433,427			$366,953		
Basic earnings per share:						
Earnings available to common shareholders	433,427	493,786	$0.88	366,953	487,538	$0.75
Effect of dilutive securities:						
401(k) equity awards	-	517		-	468	
Diluted earnings per share:						
Earnings available to common shareholders	$433,427	494,303	$0.88	$366,953	488,006	$0.75

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended June 30			
	2013	2012	2013	2012
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$24,070	$21,853	$1,182	$922
Interest cost	35,173	39,365	8,417	9,551
Expected return on plan assets	(49,613)	(52,072)	(8,253)	(7,094)
Amortization of transition obligation	—	—	206	3,580
Amortization of prior service cost (credit)	1,468	5,267	(2,438)	(1,888)
Amortization of net loss	36,038	27,467	5,646	4,487
Net periodic benefit cost	47,136	41,880	4,760	9,558
Costs not recognized and additional cost recognized due to the effects of regulation	(7,089)	(10,158)	—	973
Net benefit cost recognized for financial reporting	$40,047	$31,722	$4,760	$10,531

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(Thousands of Dollars)	Six Months Ended June 30 2013	2012	2013	2012
	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$48,141	$43,182	$2,364	$2,102
Interest cost	70,345	78,088	16,834	18,931
Expected return on plan assets	(99,226)	(103,548)	(16,506)	(14,205)
Amortization of transition obligation	—	—	412	7,160
Amortization of prior service cost (credit)	2,936	10,533	(4,876)	(3,776)
Amortization of net loss	72,076	53,785	11,292	8,452
Net periodic benefit cost	94,272	82,040	9,520	18,664
Costs not recognized and additional cost recognized due to the effects of regulation	(14,936)	(19,291)	—	1,946
Net benefit cost recognized for financial reporting	$79,336	$62,749	$9,520	$20,610

In January 2013, contributions of $191.5 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 six months ended June 30, 2013 were as follows:

(Thousands of Dollars)	Three Months Ended June 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 April 1	$(61,533)	$(135)	$(51,952)	$(113,620)
Other comprehensive loss before reclassifications	(44)	—	—	(44)
Losses reclassified from net accumulated other comprehensive loss	694	—	1,135	1,829
Net current period other comprehensive income	650	—	1,135	1,785
Accumulated other comprehensive loss at June 30	$(60,883)	$(135)	$(50,817)	$(111,835)

(Thousands of Dollars)	Six Months Ended June 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 loss before reclassifications	(31)	(36)	—	(67)
Losses reclassified from net accumulated other comprehensive loss	389	—	496	885
Net current period other comprehensive income (loss)	358	(36)	496	818
Accumulated other comprehensive loss at June 30	$(60,883)	$(135)	$(50,817)	$(111,835)

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Reclassifications from accumulated other comprehensive loss for the three and six months ended June 30, 2013 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended June 30, 2013		Six Months Ended June 30, 2013	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$1,162	(a)	$2,312	(a)
Vehicle fuel derivatives	(17)	(b)	(42)	(b)
Total, pre-tax	1,145		2,270	
Tax benefit	(451)		(1,881)	
Total, net of tax	694		389	
Defined benefit pension and postretirement losses:				
Amortization of net loss	1,769	(c)	3,538	(c)
Prior service cost	93	(c)	186	(c)
Transition obligation	2	(c)	4	(c)
Total, pre-tax	1,864		3,728	
Tax benefit	(729)		(3,232)	
Total, net of tax	1,135		496	
Total amounts reclassified, net of tax	$1,829		$885	

(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 full year earnings per share guidance and assumptions, are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outloo "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; 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 June 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 EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. EPS by subsidiary is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. 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.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended June 30	Six Months Ended June 30

Diluted Earnings (Loss) Per Share	2013	2012	2013	2012
PSCo	$0.20	$0.20	$0.43	$0.39
NSP-Minnesota	0.16	0.13	0.37	0.29
SPS	0.05	0.06	0.08	0.08
NSP-Wisconsin	0.02	0.01	0.06	0.04
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility — continuing operations	0.44	0.41	0.96	0.82
Xcel Energy Inc. and other costs	(0.04)	(0.03)	(0.08)	(0.07)
GAAP diluted earnings per share	$0.40	$0.38	$0.88	$0.75

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Xcel Energy — Overall, earnings increased $0.02 per share for the second quarter of 2013. Second quarter 2013 earnings were favorably impacted by increased electric and natural gas margins. The increase in electric margin was mainly due to rate increases in Colorado, Wisconsin, South Dakota and Texas, along with interim rate increases, subject to refund, in Minnesota and North Dakota. Natural gas margins were positively impacted by cooler weather compared with the second quarter of last year. These positive drivers were partially offset by higher O&M expenses and depreciation and amortization, reflecting our continued infrastructure investment in our utility business.

PSCo — PSCo's earnings were flat for the second quarter of 2013 and increased $0.04 per share for the six months ended June 30, 2013. Higher electric and natural gas margins and lower interest charges were offset by higher depreciation and O&M expenses. Higher margins resulted from electric rate increases, effective May 2012 and January 2013, and increased natural gas margins due to cooler weather compared to the prior year.

NSP-Minnesota — NSP-Minnesota's earnings increased $0.03 per share for the second quarter of 2013 and $0.08 per share for the six months ended June 30, 2013. Earnings were positively impacted by the Minnesota and North Dakota interim electric rates, subject to refund, an electric rate increase in South Dakota and lower interest charges. Further, natural gas margins increased due to cooler weather which contributed approximately $0.01 per share and $0.04 per share for the three and six month periods, respectively. These factors were partially offset by higher O&M expenses and depreciation.

SPS — SPS' earnings decreased $0.01 per share for the second quarter of 2013 and were flat for the six months ended June 30, 2013. Rate increases in Texas, effective May 2013, did not fully offset higher O&M expenses, depreciation and interest charges.

NSP-Wisconsin — NSP-Wisconsin's earnings increased $0.01 per share for the second quarter of 2013 and $0.02 per share for the six months ended June 30, 2013. Higher earnings from electric and gas rates, effective January 2013, and the effect of cooler weather were partially offset by higher depreciation and O&M expenses.

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, which are discussed in more detail later:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
2012 GAAP diluted earnings per share	$0.38	$0.75
Components of change — 2013 vs. 2012		
Higher electric margins	0.03	0.15
Higher natural gas margins	0.03	0.06
Higher Allowance for Funds Used During Construction (AFUDC) - Equity	0.01	0.03
Lower interest charges	0.01	0.02
Lower ETR	0.01	—
Higher taxes (other than income taxes)	—	(0.01)
Higher O&M expenses	(0.04)	(0.06)
Higher depreciation and amortization	(0.02)	(0.05)
Dilution from direct stock purchase plan and benefit plans	(0.01)	(0.01)
2013 GAAP diluted earnings per share	$0.40	$0.88

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2013	2012	2013	2012
GAAP income (loss) by segment				
Regulated electric income	$201.1	$190.2	$375.2	$333.4
Regulated natural gas income	16.0	6.2	80.9	56.4
Other income [a]	1.0	3.8	17.1	11.1
Segment income — continuing operations	218.1	200.2	473.2	400.9
Xcel Energy Inc. and other costs [a]	(21.2)	(17.1)	(39.8)	(34.0)
Total income — continuing operations	196.9	183.1	433.4	366.9
Income from discontinued operations	—	—	—	0.1
Total GAAP net income	$196.9	$183.1	$433.4	$367.0

	Three Months Ended June 30		Six Months Ended June 30	
Contributions to Diluted Earnings (Loss) Per Share	2013	2012	2013	2012
GAAP earnings (loss) by segment				
Regulated electric	$0.41	$0.39	$0.76	$0.68
Regulated natural gas	0.03	0.01	0.16	0.12
Other [a]	—	0.01	0.04	0.02
Segment earnings per share — continuing operations	0.44	0.41	0.96	0.82
Xcel Energy Inc. and other costs [a]	(0.04)	(0.03)	(0.08)	(0.07)
Total earnings per share — continuing operations	0.40	0.38	0.88	0.75
Discontinued operations	—	—	—	—
Total GAAP earnings per diluted share	$0.40	$0.38	$0.88	$0.75

[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 June 30			Six Months Ended June 30		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
HDD	22.5 %	(33.1)%	84.4 %	7.2 %	(21.4)%	35.6 %
CDD	52.2	79.9	(16.1)	51.8	83.2	(18.0)
THI	6.6	40.1	(28.0)	6.5	45.7	(30.9)

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

	Three Months Ended June 30			Six Months Ended June 30		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
Retail electric	$0.027	$0.032	$(0.005)	$0.031	$0.007	$0.024
Firm natural gas	0.007	(0.008)	0.015	0.016	(0.029)	0.045
Total	$0.034	$0.024	$0.010	$0.047	$(0.022)	$0.069

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

	Three Months Ended June 30	
	Actual	Weather Normalized
Electric residential	0.1 %	0.3 %
Electric commercial and industrial	(0.9)	(0.5)
Total retail electric sales	(0.6)	(0.2)
Firm natural gas sales [(a)]	66.0	17.2

	Six Months Ended June 30		Six Months Ended June 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 June 30		Six Months Ended June 30	
(Millions of Dollars)	2013	2012	2013	2012
Electric revenues	$2,220	$2,037	$4,312	$3,974
Electric fuel and purchased power	(1,011)	(854)	(1,936)	(1,718)
Electric margin	$1,209	$1,183	$2,376	$2,256

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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 June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Fuel and purchased power cost recovery	$153	$206
Retail rate increases (Minnesota interim, Colorado, Wisconsin, South Dakota, Texas and North Dakota interim) [(a)]	56	131
Transmission revenue	18	37
Firm wholesale	(11)	(19)
PSCo earnings test refund obligation	(9)	(9)
Conservation and DSM program incentives	(9)	(8)
Estimated impact of weather	(3)	19
Other, net	(12)	(19)
Total increase in electric revenues	$183	$338

Electric Margin

(Millions of Dollars)	Three Months Ended June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Retail rate increases (Minnesota interim, Colorado, Wisconsin, South Dakota, Texas and North Dakota interim) [(a)]	$56	$131
Transmission revenue, net of costs	10	21
PSCo earnings test refund obligation	(9)	(9)
Conservation and DSM program incentives	(9)	(8)
Firm wholesale	(8)	(13)
Estimated impact of weather	(3)	18
Other, net	(11)	(21)
Total increase in electric margin	$26	$119

(a) NSP-Minnesota recognized a reserve for revenue subject to refund of approximately $31 million and $47 million, for the three and six month periods ended June 30, 2013, respectively. See Note 5 to the consolidated financial statements for additional discussion.

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 June 30		Six Months Ended June 30	
(Millions of Dollars)	2013	2012	2013	2012
Natural gas revenues	$341	$221	1,011	$842
Cost of natural gas sold and transported	(189)	(90)	(628)	(508)
Natural gas margin	$152	$131	$383	$334

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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 June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Purchased natural gas adjustment clause recovery	$ 100	$ 122
Estimated impact of weather	12	34
Retail sales growth	7	6
Conservation and DSM program revenues (offset by expenses)	2	5
Other, net	(1)	2
Total increase in natural gas revenues	$ 120	$ 169

Natural Gas Margin

(Millions of Dollars)	Three Months Ended June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Estimated impact of weather	$ 12	$ 34
Retail sales growth	7	6
Conservation and DSM program revenues (offset by expenses)	2	5
Other, net	—	4
Total increase in natural gas margin	$ 21	$ 49

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $28.5 million, or 5.3 percent, for the second quarter of 2013 and $47.1 million, or 4.5 percent, for the six months ended June 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 June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Other electric and gas distribution expenses	$ 12	$ 13
Nuclear plant operations and amortization	9	18
Transmission costs	5	9
NSP-Minnesota storm damage restoration	4	4
Employee benefits	(2)	7
Other, net	1	(4)
Total increase in O&M expenses	$ 29	$ 47

- Other electric and gas distribution expenses were primarily driven by increased maintenance activities;
- Costs related to nuclear plant operations and amortization increased mainly due to operational initiatives;
- Increased transmission costs were related to higher substation maintenance expenditures and reliability costs;
- Storm damage restoration was due to power outages experienced during the second quarter of 2013;
- Higher year-to-date employee benefits related primarily to increased pension expense.

Depreciation and Amortization — Depreciation and amortization increased $17.3 million, or 7.6 percent, for the second quarter of 2013 and $37.3 million, or 8.2 percent, for the six months ended June 30, 2013 compared with the same periods in 2012. The increases are primarily attributable to normal system expansion.

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Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $2.4 million, or 2.4 percent, for the second quarter of 2013 and $10.2 million, or 5.0 percent, for the six months ended June 30, 2013 compared with the same periods in 2012. The increases are due to higher property taxes primarily in Minnesota, Colorado and Texas. Increased property taxes in Colorado related to the electric retail business are being deferred based on the multi-year rate settlement approved by the CPUC in May 2012 with amortization of the deferral beginning in 2013.

AFUDC — AFUDC increased $9.5 million for the second quarter of 2013 and $18.0 million for the six months ended June 30, 2013 compared with the same periods in 2012. The increases are due to construction related to the CACJA, the expansion of transmission facilities and other capital projects.

Interest Charges — Interest charges decreased $5.1 million, or 3.4 percent, for the second quarter of 2013 and $17.3 million, or 5.7 percent, for the six months ended June 30, 2013 compared with the same periods in 2012. The decreases are due to lower interest rates, primarily related to refinancings, partially offset by higher long-term debt levels to fund investments in utility operations and the write off of $6.3 million of unamortized debt expense related to the junior subordinated notes called in May 2013.

Income Taxes — Income tax expense for continuing operations decreased $2.9 million for the second quarter of 2013 compared with the same period in 2012. The decrease in income tax expense was primarily due to increased plant-related adjustments. The ETR for continuing operations was 33.4 percent for the second quarter of 2013 compared with 35.7 percent for the same period in 2012. The lower ETR for 2013 was primarily due to a tax benefit for a carryback related to 2013 and increased permanent plant-related adjustments in 2013.

Income tax expense for continuing operations increased $40.0 million for the first six 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 33.4 percent for the six months ended June 30, 2013 compared with 32.6 percent for the same period in 2012. The lower ETR for 2012 was primarily due to a discrete tax benefit of approximately $15 million for a carryback in 2012, partially offset by a tax benefit for a carryback claim related to 2013 and increased permanent plant-related adjustments in 2013.

Public Utility Regulation

NSP-Minnesota

NSP-Minnesota – Minnesota Resource Plan — In March 2013, the MPUC approved NSP-Minnesota’s 2011-2025 Resource Plan. The MPUC ordered that a competitive acquisition process be conducted with the goal of adding approximately 500 MW of generation to the NSP System between 2017 and 2019. In February 2013, NSP-Minnesota also issued a Request for Proposal (RFP) for up to 200 MW of wind generation, to the extent that cost effective opportunities can be identified. Proposals for both RFPs may be for purchase power agreements (PPA), self-build or contracts with a build-ownership transfer option. Bid proposals in response to the two RFPs were received in April 2013.

The competitive acquisition schedule is expected to be as follows:

- Continued evaluation of generation bids through contested case process managed by ALJ – August-October 2013
- ALJ will report to the MPUC which project should be selected – December 2013
- MPUC to make a final ruling – February-March 2014

On July 16, 2013, NSP-Minnesota filed a petition with the MPUC seeking approval of three 200 MW wind generation projects. NSP-Minnesota requested approval by October 2013. Potential projects are as follows:

- Odell is a 200 MW wind farm located near Mountain Lake, Minn. This is a 20-year PPA with Geronimo Energy. The project is expected to be operational in late 2015.
- Courtenay is a 200 MW wind farm located near Jamestown, N.D. This is a 20-year PPA with Geronimo Energy. The project is expected to operational by September 2015.
- Pleasant Valley is a 200 MW wind farm to be located near Austin, Minn. It will be developed and constructed by RES Americas, who will transfer ownership to NSP-Minnesota upon construction completion. Pleasant Valley is expected to operational by October 2015.
- In addition, NSP-Minnesota has been in discussions with RES Americas regarding an additional 150 MW build-ownership project. This may be brought to the MPUC and the NDPSC in separate petitions, depending on transmission costs which will be determined by MISO.

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CapX2020 Transmission Expansion — In 2009, the MPUC approved separate Certificate of Need (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 certificate of public convenience and necessity (CPCN) for the Wisconsin portion of the project. Federal approval of the project was granted in January 2013. Two parties filed an appeal with the Minnesota Court of Appeals against the MPUC's route permit decision, and the Court of Appeals issued an order on June 10, 2013, upholding the MPUC's determination. One party has requested Minnesota Supreme Court review of the MPUC's route permit decision, citing similar arguments to those presented unsuccessfully to the Court of Appeals. On July 3, 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 which at least 10 percent must be rooftop, of a public utility's total electric retail sales to retail customers be generated using solar energy by 2020. The legislation also authorized two new solar programs, a community solar garden program that must have a minimum of five subscribers and a new solar energy program that authorizes the spending of five million dollars over five years to implement a solar energy production incentive payment for solar energy systems equal to or less than 20 kilowatts. Both programs require approval by the MPUC. Xcel Energy is currently assessing the impact of this legislation.

Minnesota Multi-Year Plan — In June 2013, the MPUC issued guidelines to allow utilities within its jurisdiction to file multi-year rate plans. Under a multi-year rate plan, utilities would be required to show clearly identified capital projects and non-capital costs for which it sought recovery over a period no longer than three years. NSP-Minnesota would file fixed rates over the period, with one ROE applying throughout the plan. A multi-year plan request would be filed within the context of a general rate case.

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. While this may set a limitation of monthly FCA costs, it would be largely based on costs NSP-Minnesota does not control, such as the price of fuel and not recognize new events or changed circumstances which would dilute the impact of those events and circumstances until three or more years had passed. NSP-Minnesota's reply comments are expected to be filed in August 2013.

Minneapolis, Minn. Franchise Agreement — On June 28, 2013, two measures were authorized by the Minneapolis City Council. The first measure allowed for public hearings to be held regarding the establishment of a municipal electric and natural gas utility. These hearings were held on Aug. 1, 2013. The Minneapolis City Council has until Aug. 16, 2013 to vote on placing a measure on the November 2013 ballot to further pursue forming a municipal utility. The second measure authorized a $250,000 study that will 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. Any potential municipalization of the public utilities would require a vote of the Minneapolis City Council to authorize the city to establish a municipal utility, and a subsequent special election to obtain voter ratification of the council action.

Should Minneapolis attempt to condemn Xcel Energy facilities, Xcel Energy would seek to obtain full compensation for the property and business taken by Minneapolis and for all damages resulting to Xcel Energy and its system. Xcel Energy would also seek appropriate compensation for stranded costs with the FERC.

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.

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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 and a request for additional information to all licensees. 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 request for additional information included 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 that superseded the March 2012 order. 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 for both the March 2012 and June 2013 orders 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 Power Uprates

Monticello Nuclear Plant EPU — In 2008, NSP-Minnesota filed for both state and federal approvals of an EPU of approximately 71 MW for NSP-Minnesota's Monticello nuclear generating plant. The MPUC approved the CON for the EPU in 2008. The NRC staff has placed the license amendment filing on hold to address concerns raised by the Advisory Committee on Reactor Safeguards 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. 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, which concluded when the plant commenced operations on July 19, 2013. However, the plant will not be permitted to operate at the higher uprate capacity levels without NRC approval. NSP-Minnesota expects to receive approval of the EPU license by the NRC in the second half of 2013. The method and timing of rate recovery of the costs associated with the Monticello life extension and EPU construction projects is included as part of the 2013 electric rate case. Ultimately, the project costs will be subject to a prudence review by the MPUC as part of the 2014 electric rate case, currently planned to be filed in the fall 2013.

The EPU project was completed concurrently with life cycle management (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. The total construction budget estimate for the LCM/EPU project of $587 million (determined in late 2011) was included in the 2013 Minnesota electric rate case filing and revised during the case to $640 million. Final costs of the project after completion of the 2013 outage are now projected to be approximately $650 million, 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 outages.

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PSCo

Colorado 2011 Electric Resource Plan (ERP), 2013 All-Source Solicitation and Renewable Energy Standard (RES) Plan — In January 2013, the CPUC approved with modifications the 2011 ERP. Consistent with the ERP, in March 2013, PSCo issued an All-Source RFP for 250 MW by the end of 2018. Proposals for the All-Source RFP may be for purchase power agreements, self-build or contracts with a build-ownership transfer option. PSCo also issued a separate wind RFP for purchase power agreements only. Bid proposals in response to the Wind RFP were received in April 2013. The CPUC recommended that PSCo include 548 MW of wind in its resource portfolios for modeling purposes. The CPUC approved the inclusion of the least cost wind bid in portfolios for modeling purposes and sought additional information regarding the wind bids in the September All-Source evaluation assessment before approving any of the acquisitions. In July 2013, the 2014 RES plan was filed.

Next steps in the 2013 All-Source RFP schedule are expected to be as follows:

- Delivery of the All-Source evaluation assessment report to CPUC – September 2013
- CPUC evaluation and regulatory approval of wind-based generation proposals – October 2013
- CPUC evaluation and regulatory approval of All-Source generation proposals – December 2013

Boulder, Colo. Franchise Agreement — 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. Boulder's authorization of any condemnation action requires two readings (i.e., votes) by the City Council. On July 24, 2013, the City Council on first reading voted in favor of an ordinance authorizing the acquisition of the PSCo transmission and distribution system in and near Boulder. The second, and final, vote is scheduled for Aug. 6, 2013.

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, that the CPUC can only grant one CPCN per area and that the CPUC has already issued to PSCo a CPCN for this area. The CPUC has set a briefing schedule for this petition.

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. Both PSCo and the CPUC filed pleadings in opposition to Boulder's request. In July 2013, the FERC denied Boulder's petition, without prejudice.

Consistent with our approach to condemnation actions where PSCo is the condemnee, should Boulder attempt to condemn PSCo facilities, 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. PSCo would also seek appropriate compensation for stranded costs with the FERC.

SPS

Texas Tax Legislation — Texas has enacted a change in law that eliminates the use of a Consolidated Tax Savings Adjustment (CTSA) in electric utility rate cases. The revised law takes effect Sept. 1, 2013 and applies to rate cases filed on or after that date. Under the settlement agreement approved by the PUCT in SPS' recently concluded rate case, the earliest SPS is allowed to file its next base rate case is January 2014. The new law eliminating the use of a CTSA will apply to that rate case. SPS does not expect it to have a material impact on the results of operations, financial position or cash flows.

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. Pending regulatory approval, these PPAs are estimated to provide cost savings to customers. A decision is expected from the NMPRC in fourth quarter 2013.

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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. On June 7, 2013, the Court of Appeals for 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). 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.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — The FERC issued Order 1000 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 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 May 28, 2013. The FERC is expected to submit its responsive brief in September 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 transmission within their footprints. Rather, the FERC required that 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 compliance filings for MISO and PSCo, directing further changes to fully address the requirements of Order 1000. The FERC's ruling on the SPP compliance was issued on July 18, 2013 as discussed below. The due date for the further compliance filing to address PSCo and WestConnect's regional planning and cost allocation requirements has been extended to Sept. 20, 2013. In addition, SPP and MISO have received an extension of the deadline for filing their interregional planning and cost allocation agreement with the Midcontinent Area Power Pool (MAPP) which will likely delay that filing until late third quarter of 2013. Filings to address MISO and SPP interregional planning and cost allocation requirements with other regions were made on July 10, 2013.

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.

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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, including the requirement that cost allocation for new projects identified through the planning process be binding upon all participants in the planning process. This requirement poses a challenge because WestConnect is comprised of a number of utilities that are not subject to FERC jurisdiction and are unwilling to participate in a regional planning or cost allocation process if they do not have the ultimate authority to decline to help fund a project identified through the regional process. On April 22, 2013, PSCo and other WestConnect members requested rehearing on various aspects of the March 2013 order, including the requirement that cost allocation be binding. The WestConnect members filed the interregional compliance filing on May 10, 2013.

The FERC issued its initial order on SPP's Order 1000 compliance filing on July 18, 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. It is expected that SPP and other parties will request rehearing of some aspects of the FERC's order; requests for rehearing are due Aug. 19, 2013. The further SPP compliance filing is due Nov. 15, 2013. 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.

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 June 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 nonperformance risk.

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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.

At June 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	$7,918	$16,085	$1,398	$643	$26,044
NSP-Minnesota	2	(385)	—	—	—	(385)
PSCo	1	474	—	—	—	474
		$8,007	$16,085	$1,398	$643	$26,133

	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	$266	$55	$—	$—	$321

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:

	Six Months Ended June 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	(3,863)	(6,070)
Commodity trading contract additions and changes during period	2,003	6,899
Fair value of commodity trading net contract assets outstanding at June 30	$26,454	$21,253

At June 30, 2013, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1.2 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1.2 million. At June 30, 2012, a 10 percent increase or decrease in market prices for commodity trading contracts would have an immaterial impact on pretax income from continuing operations.

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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 Month Ended June 30	VaR Limit	Average	High	Low
2013	$0.43	$3.00	$0.70	$1.47	$0.21
2012	0.49	3.00	0.42	1.56	0.15

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 June 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 $6.3 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

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 June 30, 2013, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $5.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $13.7 million. At June 30, 2012, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $6.4 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $9.4 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 June 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 OCI 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 June 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 3.3 percent and 37.6 percent of total assets and liabilities, respectively, measured at fair value at June 30, 2013.

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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 $52.5 million and $5.3 million of estimated fair values, respectively, for FTRs held at June 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 an immaterial amount for forwards and options held at June 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 $83.7 million in the nuclear decommissioning fund at June 30, 2013 (approximately 5.3 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.

Liquidity and Capital Resources

Cash Flows

	Six Months Ended June 30	
(Millions of Dollars)	2013	2012
Cash provided by operating activities	$1,074	$865

Net cash provided by operating activities increased $209 million for the six months ended June 30, 2013, compared with the six months ended June 30, 2012. The increase was the result of higher net income, changes in working capital due to the timing of payments and receipts and the effect of income taxes paid in 2012 compared to refunds received in 2013.

	Six Months Ended June 30	
(Millions of Dollars)	2013	2012
Cash used in investing activities	$(1,512)	$(956)

Net cash used in investing activities increased $556 million for the six months ended June 30, 2013, compared with the six months ended June 30, 2012. The increase was the result of higher capital expenditures related to nuclear, transmission and CACJA projects, partially offset by the change in restricted cash associated with the nuclear waste disposal settlement with the U.S. Department of Energy in 2012.

	Six Months Ended June 30	
(Millions of Dollars)	2013	2012
Cash provided by financing activities	$414	$94

Net cash provided by financing activities increased $320 million for the six months ended June 30, 2013, compared with the six months ended June 30, 2012. The increase was primarily due to higher proceeds from the issuances of long-term debt and common stock, partially offset by repayments of previously existing short and long-term debt, higher dividend payments and common stock purchases made in 2012.

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.

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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 is conducting legal reviews associated with the additional reporting obligations for "trade options," which are physical electric and gas contracts that contain embedded volumetric and/or price optionality. The reporting requirements were subject to begin in April 2013, however the CFTC has issued two "no action" letters that effectively suspend reporting obligations for "trade options" until March 2014 and commodity swaps until October 2013. The "no action letters" did, however, leave in place data gathering requirements. Xcel Energy is prepared to meet these requirements.

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 January 2013, contributions of $191.5 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.
- 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 June 30, 2013, approximately $2.5 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.

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Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2013		Twelve Months Ended Dec. 31, 2012	
Borrowing limit	$2,450		$2,450	
Amount outstanding at period end	354		602	
Average amount outstanding	255		403	
Maximum amount outstanding	487		634	
Weighted average interest rate, computed on a daily basis	0.29	%	0.35	%
Weighted average interest rate at period end	0.27		0.36	

Credit Facilities — As of July 25, 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	$240.0	$560.0	$0.4	$560.4
PSCo	700.0	4.6	695.4	0.6	696.0
NSP-Minnesota	500.0	101.2	398.8	0.2	399.0
SPS	300.0	134.0	166.0	0.5	166.5
NSP-Wisconsin	150.0	12.0	138.0	0.5	138.5
Total	$2,450.0	$491.8	$1,958.2	$2.2	$1,960.4

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

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.

Xcel Energy Inc. and its utility subsidiaries completed the following financings in 2013:

- In March, 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.
- In May, Xcel Energy Inc. issued $450 million of 0.75 percent senior unsecured notes due May 9, 2016.
- In May, NSP-Minnesota issued $400 million of 2.60 percent first mortgage bonds due May 15, 2023.

In addition, SPS may issue approximately $100 million of first mortgage bonds in the third quarter of 2013.

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. As of June 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 the 7.60 percent junior subordinated notes. Upon redemption, Xcel Energy Inc. recognized $6.3 million of related unamortized debt issuance costs as interest charges.

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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 earnings guidance is $1.85 to $1.95 per share. Key assumptions related to 2013 earnings are detailed below:

- Rate case outcomes consistent with current expectations.
- 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 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 $75 million to $85 million over 2012 levels.
- Property taxes are projected to increase approximately $20 million to $25 million over 2012 levels.
- Interest expense (net of AFUDC - debt) is projected to decrease $40 million to $45 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.

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 June 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 June 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
April 1, 2013 — April 30, 2013	—	—	—	—
May 1, 2013 — May 31, 2013	—	—	—	—
June 1, 2013 — June 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)).
4.01*	Supplemental Indenture No. 7 dated as of May 1, 2013 between Xcel Energy and Wells Fargo Bank, National Association, as Trustee, creating $450 million principal amount of 0.75 percent Senior Notes, Series due May 9, 2016. (Exhibit 4.01 to Form 8-K dated May 9, 2013 (file no. 001-03034))
4.02*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60 percent First Mortgage Bonds, Series due May 15, 2023. (Exhibit 4.01 to NSP-Minnesota's Form 8-K dated May 20, 2013 (file no. 001-31387))
10.01+	First Amendment dated May 21, 2013 to the Xcel Energy Inc. Long Term Incentive Plan (as amended and restated effective Feb. 17, 2010).
10.02+	Second Amendment dated May 21, 2013 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement).
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 June 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.
Aug. 2, 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)

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