XCEL ENERGY INC
Form 10-Q
May 02, 2014

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 March 31, 2014
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 April 28, 2014
Common Stock, $2.50 par value	501,969,728 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 March 31	
	2014	2013
Operating revenues		
Electric	$2,301,710	$2,092,196
Natural gas	879,688	669,596
Other	21,206	21,057
Total operating revenues	3,202,604	2,782,849
Operating expenses		
Electric fuel and purchased power	1,067,321	925,043
Cost of natural gas sold and transported	623,828	439,375
Cost of sales — other	9,129	8,411
Operating and maintenance expenses	560,143	529,231
Conservation and demand side management program expenses	77,546	64,032
Depreciation and amortization	245,943	248,706
Taxes (other than income taxes)	124,702	113,427
Total operating expenses	2,708,612	2,328,225
Operating income	493,992	454,624
Other income, net	3,201	3,922
Equity earnings of unconsolidated subsidiaries	7,438	7,577
Allowance for funds used during construction — equity	21,907	19,754
Interest charges and financing costs		
Interest charges — includes other financing costs of $5,792 and $5,809, respectively	139,094	139,631
Allowance for funds used during construction — debt	(9,548)	(8,758)
Total interest charges and financing costs	129,546	130,873
Income before income taxes	396,992	355,004
Income taxes	135,771	118,434
Net income	$261,221	$236,570
Weighted average common shares outstanding:		
Basic	499,523	489,781
Diluted	499,746	490,531
Earnings per average common share:		
Basic	$0.52	$0.48

Diluted	0.52	0.48
Cash dividends declared per common share	$0.30	$0.27

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 March 31	
	2014	2013
Net income	$261,221	$236,570
Other comprehensive income (loss)		
Pension and retiree medical benefits:		
Amortization of losses (gains) included in net periodic benefit cost, net of tax of $550 and $2,503, respectively	864	(639)
Derivative instruments:		
Net fair value (decrease) increase, net of tax of $(5) and $12, respectively	(7)	13
Reclassification of losses (gains) to net income, net of tax of $358 and $1,429, respectively	560	(305)
	553	(292)
Marketable securities:		
Net fair value increase (decrease), net of tax of $24 and $(18), respectively	38	(36)
Other comprehensive income (loss)	1,455	(967)
Comprehensive income	$262,676	$235,603

See Notes to Consolidated Financial Statements

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

	Three Months Ended March 31	
	2014	2013
Operating activities		
Net income	$261,221	$236,570
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	250,343	253,004
Conservation and demand side management program amortization	1,555	1,712
Nuclear fuel amortization	28,862	27,522
Deferred income taxes	150,464	130,662
Amortization of investment tax credits	(1,443)	(1,657)
Allowance for equity funds used during construction	(21,907)	(19,754)
Equity earnings of unconsolidated subsidiaries	(7,438)	(7,577)
Dividends from unconsolidated subsidiaries	8,850	9,539
Share-based compensation expense	5,370	8,167
Net realized and unrealized hedging and derivative transactions	7,384	217
Changes in operating assets and liabilities:		
Accounts receivable	(140,962)	(72,205)
Accrued unbilled revenues	111,417	76,602
Inventories	140,301	87,865
Other current assets	(66,320)	(51,203)
Accounts payable	(37,730)	5,311
Net regulatory assets and liabilities	(253)	88,572
Other current liabilities	1,008	20,318
Pension and other employee benefit obligations	(125,780)	(181,091)
Change in other noncurrent assets	48,054	24,594
Change in other noncurrent liabilities	(20,347)	5,160
Net cash provided by operating activities	592,649	642,328
Investing activities		
Utility capital/construction expenditures	(822,628)	(752,251)
Proceeds from insurance recoveries	4,260	23,500
Allowance for equity funds used during construction	21,907	19,754
Purchases of investments in external decommissioning fund	(229,548)	(586,239)
Proceeds from the sale of investments in external decommissioning fund	227,901	584,948
Investment in WYCO Development LLC	(1,161)	(231)
Other, net	(1,501)	(2,745)
Net cash used in investing activities	(800,770)	(713,264)
Financing activities		
Proceeds from (repayments of) short-term borrowings, net	6,000	(177,000)
Proceeds from issuance of long-term debt	295,999	494,282
Repayments of long-term debt, including reacquisition premiums	(224)	(251,367)
Proceeds from issuance of common stock	63,548	160,084
Dividends paid	(132,033)	(124,426)
Net cash provided by financing activities	233,290	101,573

Net change in cash and cash equivalents	25,169	30,637
Cash and cash equivalents at beginning of period	107,144	82,323
Cash and cash equivalents at end of period	$132,313	$112,960
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(152,522)	$(153,498)
Cash (paid) received for income taxes, net	(164)	17,939
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$290,058	$256,530
Issuance of common stock for reinvested dividends and 401(k) plans	14,525	18,791

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)

	March 31, 2014	Dec. 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$132,313	$107,144
Accounts receivable, net	885,098	744,160
Accrued unbilled revenues	575,813	687,230
Inventories	436,237	576,538
Regulatory assets	481,473	417,801
Derivative instruments	70,275	91,707
Deferred income taxes	252,658	341,202
Prepayments and other	295,479	252,258
Total current assets	3,129,346	3,218,040
Property, plant and equipment, net	26,541,482	26,122,159
Other assets		
Nuclear decommissioning fund and other investments	1,793,067	1,755,990
Regulatory assets	2,497,280	2,509,218
Derivative instruments	67,513	84,842
Other	170,064	217,241
Total other assets	4,527,924	4,567,291
Total assets	$34,198,752	$33,907,490
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$282,133	$280,763
Short-term debt	765,000	759,000
Accounts payable	1,061,874	1,261,238
Regulatory liabilities	258,946	274,769
Taxes accrued	461,520	378,766
Accrued interest	132,589	159,372
Dividends payable	150,250	139,432
Derivative instruments	22,358	23,382
Other	333,078	377,776
Total current liabilities	3,467,748	3,654,498
Deferred credits and other liabilities		
Deferred income taxes	5,412,381	5,331,046
Deferred investment tax credits	77,796	79,239
Regulatory liabilities	1,090,733	1,059,395
Asset retirement obligations	1,838,521	1,815,390
Derivative instruments	199,578	209,224
Customer advances	272,583	275,555
Pension and employee benefit obligations	642,126	769,222

Other	244,543	237,217
Total deferred credits and other liabilities	9,778,261	9,776,288
Commitments and contingencies		
Capitalization		
Long-term debt	11,205,319	10,910,754
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 501,151,619 and 497,971,508 shares outstanding at March 31, 2014 and Dec. 31, 2013, respectively	1,252,879	1,244,929
Additional paid in capital	5,681,150	5,619,313
Retained earnings	2,918,215	2,807,983
Accumulated other comprehensive loss	(104,820)	(106,275)
Total common stockholders' equity	9,747,424	9,565,950
Total liabilities and equity	$34,198,752	$33,907,490

See Notes to Consolidated Financial Statements

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

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
	Shares	Par Value				
Three Months Ended March 31, 2014 and 2013						
Balance at Dec. 31, 2012	487,960	$1,219,899	$5,353,015	$2,413,816	$ (112,653)	$8,874,077
Net income				236,570		236,570
Other comprehensive loss					(967)	(967)
Dividends declared on common stock				(134,054)		(134,054)
Issuances of common stock	6,795	16,989	151,845			168,834
Share-based compensation			10,653			10,653
Balance at March 31, 2013	494,755	$1,236,888	$5,515,513	$2,516,332	$ (113,620)	$9,155,113
Balance at Dec. 31, 2013	497,972	$1,244,929	$5,619,313	$2,807,983	$ (106,275)	$9,565,950
Net income				261,221		261,221
Other comprehensive income					1,455	1,455
Dividends declared on common stock				(150,989)		(150,989)
Issuances of common stock	3,180	7,950	55,772			63,722
Share-based compensation			6,065			6,065
Balance at March 31, 2014	501,152	$1,252,879	$5,681,150	$2,918,215	$ (104,820)	$9,747,424

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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 March 31, 2014 and Dec. 31, 2013; the results of its operations, including the components of net income and comprehensive income, and changes in stockholders' equity for the three months ended March 31, 2014 and 2013; and its cash flows for the three months ended March 31, 2014 and 2013. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2014 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, 2013 balance sheet information has been derived from the audited 2013 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2013. 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, 2013, filed with the SEC on Feb. 21, 2014. 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, 2013, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently issued accounting pronouncements that have been adopted in the current period did not materially impact the consolidated financial statements, and no material impact is expected from accounting pronouncements issued and pending implementation.

3. Selected Balance Sheet Data

(Thousands of Dollars)	March 31, 2014	Dec. 31, 2013
Accounts receivable, net		
Accounts receivable	$939,228	$797,267
Less allowance for bad debts	(54,130)	(53,107)
	$885,098	$744,160

(Thousands of Dollars)	March 31, 2014	Dec. 31, 2013
Inventories		
Materials and supplies	$229,299	$225,308
Fuel	149,190	189,485
Natural gas	57,748	161,745
	$436,237	$576,538

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(Thousands of Dollars)	March 31, 2014	Dec. 31, 2013
Property, plant and equipment, net		
Electric plant	$30,562,428	$30,341,310
Natural gas plant	4,156,606	4,086,651
Common and other property	1,477,531	1,485,547
Plant to be retired [a]	92,050	101,279
Construction work in progress	2,672,049	2,371,566
Total property, plant and equipment	38,960,664	38,386,353
Less accumulated depreciation	(12,741,176)	(12,608,305)
Nuclear fuel	2,193,544	2,186,799
Less accumulated amortization	(1,871,550)	(1,842,688)
	$26,541,482	$26,122,159

(a) As a result of the 2010 Colorado Public Utilities Commission (CPUC) approval of PSCo's Clean Air Clean Jobs Act (CACJA) compliance plan and the December 2013 approval of PSCo's preferred plans for applicable generating resources, PSCo has received approval for early retirement of Cherokee Unit 3 and Valmont Unit 5 between 2015 and 2017. 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, 2013 appropriately represent, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Tax Loss Carryback Claims — In 2012 and 2013, Xcel Energy identified certain expenses related to 2009, 2010, 2011 and 2013 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $15 million in 2012 and $12 million in 2013.

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, including the 2009 carryback claim. As of March 31, 2014, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $10 million of income tax expense for the 2009 through 2011 claims and the anticipated claim for 2013. Xcel Energy is continuing to work through the audit process, but the outcome and timing of a resolution is uncertain.

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 March 31, 2014, 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	2009
Minnesota	2009
Texas	2009
Wisconsin	2009

In the first quarter of 2014, the state of Wisconsin completed an examination of tax years 2009 through 2011. No material adjustments were proposed for those tax years. As of March 31, 2014, there were no state income tax audits in progress.

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

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

(Millions of Dollars)	March 31, 2014	Dec. 31, 2013
Unrecognized tax benefit — Permanent tax positions	$7.4	$12.9
Unrecognized tax benefit — Temporary tax positions	27.8	28.3
Total unrecognized tax benefit	$35.2	$41.2

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)	March 31, 2014	Dec. 31, 2013
NOL and tax credit carryforwards	$(23.0)	$(27.1)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS audit progresses and state audits resume. As the IRS examination moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $8 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 March 31, 2014 and Dec. 31, 2013 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2014 or Dec. 31, 2013.

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, 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)

NSP Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the MPUC. The rate case is based on a requested return on equity (ROE) of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015.

The NSP-Minnesota electric rate case reflects an overall increase in revenues of approximately $193 million or 6.9 percent in 2014 and an additional $98 million or 3.5 percent in 2015. The request includes a proposed rate moderation plan for 2014 and 2015. After reflecting interim rate adjustments, NSP-Minnesota is requesting a rate increase of $127 million or 4.6 percent in 2014 and an incremental rate increase of $164 million or 5.6 percent in 2015.

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the excess depreciation reserve which the MPUC approved in NSP-Minnesota's last electric rate case and the use of expected funds from the U.S. Department of Energy (DOE) for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund NSP-Minnesota's decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello life cycle management (LCM)/extended power uprate (EPU) project costs and NSP-Minnesota's request to amortize amounts associated with the canceled Prairie Island EPU project. NSP-Minnesota may file a petition for deferred accounting regarding these Monticello costs later in 2014.

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

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

In December 2013, the MPUC approved interim rates of $127 million effective Jan. 3, 2014, subject to refund. The MPUC determined that the costs of Sherco Unit 3 would be allowed in interim rates, and that NSP-Minnesota's request to accelerate the depreciation reserve amortization was a permissible adjustment to its interim rate request.

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

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

A final MPUC decision is anticipated in March 2015.

NSP-Minnesota – Nuclear Project Prudence Investigation — The MPUC has initiated an investigation to determine whether the costs in excess of the $320 million included in the certificate of need (CON) for NSP-Minnesota's Monticello LCM/EPU project were prudent. The final costs for the Monticello LCM/EPU project were approximately $665 million.

In October 2013, NSP-Minnesota filed a report to further support the change and prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and (3) additional Nuclear Regulatory Commission (NRC) licensing related requests over the five-plus year application process. NSP-Minnesota has provided information that the cost deviation is in line with similar upgrade projects undertaken by other utilities and the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and has begun the process to comply with the license requirements for higher power levels, subject to NRC oversight and review.

At the direction of the MPUC, the Minnesota Department of Commerce (DOC) has retained a consultant to assist in their review. The consultant, Global Energy and Water Consulting, LLC is covering the cost split between LCM and

EPU; reasons for the cost increases; project management and oversight; and the prudence of scope changes among others. The results and any recommendations from the conclusion of this prudence proceeding are expected to be considered by the MPUC in NSP-Minnesota's 2014 Minnesota electric rate case. The next steps in the procedural schedule are expected to be as follows:

- Direct Testimony — July 2, 2014;
- Rebuttal Testimony — Aug. 26, 2014;
- Surrebuttal Testimony — Sept. 19, 2014;
- Hearing — Sept. 29 - Oct. 3, 2014;

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- Reply Brief — Nov. 21, 2014; and
- ALJ Report — Dec. 31, 2014.

A final MPUC decision is anticipated in the first quarter of 2015.

Recently Concluded Regulatory Proceedings — North Dakota Public Service Commission (NDPSC)

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

In February 2014, the NDPSC approved a four-year rate plan settlement. The approved plan will provide increased revenues of approximately $7.4 million, $9.4 million and $10.1 million, an annual rate increase of 4.9 percent for 2013, 2014 and 2015 respectively, with no increase in 2016. Additionally, the rate plan includes a gradually increasing ROE of 9.75, 10.0, 10.0 and 10.25 percent for 2013 through 2016, respectively. Final rates for 2013 and the 2014 rate increase went into effect May 1, 2014. The 2015 rate increase will take effect Jan. 1, 2015.

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo – Colorado 2013 Gas Rate Case — In December 2012, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas rates by $48.5 million in 2013 with subsequent step increases of $9.9 million in 2014 and $12.1 million in 2015. The request was based on a 2013 FTY, a 10.5 percent ROE, a rate base of $1.3 billion and an equity ratio of 56 percent. Interim rates, subject to refund, went into effect in August 2013.

In April 2013, PSCo revised its requested annual rate increase to $44.8 million for 2013, with subsequent step increases of $9.0 million for 2014 and $10.9 million for 2015, based on an ROE of 10.3 percent. This requested increase included amounts to be transferred from the Pipeline System Integrity Adjustment (PSIA) rider mechanism.

In December 2013, the CPUC approved a natural gas base rate increase of approximately $15.8 million based on an ROE of 9.72 percent, a historic test year (HTY) with an end of year rate base and an equity ratio of 56 percent.

The following table summarizes the CPUC decision:

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

Rates and conforming changes made to the PSIA were effective Jan. 1, 2014. In April 2014, the CPUC approved PSCo’s request to refund $6.6 million to customers, excluding amounts related to the PSIA rider mechanism. The refund represents the difference between the interim rates collected and the final approved rates and will be returned between April 2014 and March 2015.

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

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In October 2013, PSCo, the CPUC Staff, the Office of Consumer Counsel (OCC) and Colorado Energy Consumers filed a comprehensive settlement which tied the outcome of the steam rate case to key issues to be decided in the natural gas rate case, including ROE and capital structure. The settlement allowed the filed rates to be effective on Jan. 1, 2014, subject to refund. Final rates allowing a rate increase of $2.3 million annually were implemented on Feb. 1, 2014.

PSCo – Annual Electric Earnings Test — An earnings sharing mechanism is used to apply prospective electric rate adjustments for earnings in the prior year that exceed PSCo’s authorized ROE threshold of 10 percent. PSCo filed a tariff for the 2013 earnings test with the CPUC on April 30, 2014, proposing a refund obligation of $45.7 million to electric customers to be returned between August 2014 and July 2015. As of March 31, 2014, PSCo has also recognized management’s best estimate of an accrual for 2014.

Electric Commodity Adjustment (ECA) Prudence Review — In September 2013, the CPUC Staff requested that the 2012 annual ECA prudence review be set for hearing. The prudence review, as determined by the ALJ, will primarily consider if replacement power costs during outages of certain jointly owned facilities were properly allocated between wholesale and retail customers. A decision is anticipated later in 2014.

2012 PSIA Report — In April 2013, PSCo filed its 2012 PSIA report, requesting $43.5 million for recovery of expenditures. The OCC and CPUC Staff requested that 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. In July 2013, the CPUC approved the request and assigned the matter to an ALJ.

In February 2014, PSCo, the CPUC Staff and the OCC agreed to a settlement amount of $43.4 million for recovery of 2012 expenditures, subject to final approval. This includes a one-time disallowance of approximately $0.1 million of operating and maintenance (O&M) expenditures in 2012 and an agreement not to disallow capital expenditures related to a pipeline replacement project. In March 2014, the ALJ waived the need for a hearing on the settlement. An ALJ recommended decision is anticipated later in 2014.

Electric, Purchased Gas and Resource Adjustment Clauses

Renewable Energy Credit (REC) Sharing — In 2011, the CPUC approved margin sharing on stand-alone REC transactions at 10 percent to PSCo and 90 percent to customers for 2014. In 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 renewable energy standard adjustment (RESA) regulatory asset balance. PSCo’s credit to the RESA regulatory asset balance was not material for the three months ended March 31, 2014. For the three months ended March 31, 2013, PSCo credited the RESA regulatory asset balance $4.0 million. The cumulative credit to the RESA regulatory asset balance was $104.6 million and $104.5 million at March 31, 2014 and Dec. 31, 2013, respectively. The credits include the customers’ share of REC trading margins and the unspent share of carbon offset funds.

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

ECA / RESA Adjustment — In July 2013, PSCo advised the CPUC that it had inadvertently allocated purchased power expense between the deferred accounts for the ECA and the RESA from 2010 to 2012. PSCo proposed to transfer from the RESA deferred account to the ECA deferred account approximately $26.2 million and to amortize the recovery of this amount over 12 months. In 2014, the ALJ and the CPUC determined that the $26.2 million was prudently incurred and recommended full recovery through the ECA over a 12 month period with interest accrued at the ECA interest rate. The difference between the RESA interest rate and the ECA interest rate was a decrease of approximately 7.4 percent, or $4.3 million, and was reflected in 2013 earnings.

Pending Regulatory Proceedings — Federal Energy Regulatory Commission (FERC)

PSCo Transmission Formula Rate Cases — In April 2012, PSCo filed with the FERC to revise the wholesale transmission formula rates from a HTY formula rate to a forecast transmission formula rate and to establish formula ancillary services rates. PSCo proposed that the formula rates be updated annually to reflect changes in costs, subject to a true-up. The request would increase PSCo's wholesale transmission and ancillary services revenue by approximately $2.0 million annually. Various transmission customers taking service under the tariff protested the filing. In June 2012, the FERC issued an order accepting the proposed transmission and ancillary services formula rates, suspending the increase to November 2012, subject to refund, and setting the case for settlement judge or hearing procedures.

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In June 2012, several wholesale customers filed a complaint with the FERC seeking to have the transmission formula rate ROE reduced from 10.25 to 9.15 percent effective July 1, 2012. If implemented, the ROE reduction would reduce PSCo transmission and ancillary rate revenues by approximately $1.8 million annually. In October 2012, the FERC issued an order accepting the complaint, consolidating the complaint with the April 2012 formula rate change filing, establishing a refund effective date of July 1, 2012, and setting the complaint for settlement judge and hearing procedures.

In December 2013, the FERC approved a partial settlement resolving all issues related to the April 2012 transmission rate filing and June 2012 complaint other than ROE. The settlement is not expected to materially increase 2014 transmission revenues. The ROE issue is now subject to an evidentiary hearing process.

In March 2014, the FERC Staff filed testimony supporting an ROE of 8.91 percent for July 2012 to November 2012, and an ROE of 8.70 percent thereafter. The case is scheduled for a hearing before an ALJ in May 2014, with the ALJ recommended decision expected by September 2014.

SPS

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

SPS – Texas 2014 Electric Rate Case — In January 2014, SPS filed a retail electric rate case in Texas with each of its Texas municipalities and the PUCT for a net increase in annual revenue of approximately $52.7 million, or 5.8 percent. The net increase reflected a base rate increase, revenue credits transferred from base rates to rate riders or the fuel clause, and resetting the Transmission Cost Recovery Factor (TCRF) to zero when the final base rates become effective.

The rate filing was based on a HTY ending June 2013, a requested ROE of 10.40 percent, an electric rate base of approximately $1.27 billion and an equity ratio of 53.89 percent. The requested rate increase reflected an increase in depreciation expense of approximately $16 million.

In April 2014, SPS revised its requested rate increase to approximately $48.1 million, or 5.3 percent, based on updated information. The following table summarizes SPS' revised request:

(Millions of Dollars)	SPS Request	
Adjusted base rate increase	$76.9	
Resetting TCRF	(12.9	)
Credit to customers for gain on sale to Lubbock moved to a rider	(4.9	)
Adjusted net increase in base revenue	59.1	
Fuel clause offsets	(11.0	)
Adjusted retail customer net bill impact	$48.1	

The PUCT has suspended SPS' proposed rates through Oct. 31, 2014. If the PUCT has not issued a final order by July 11, 2014, then SPS' current rates will not change, but final rates, when approved by the PUCT, will be made effective retroactive to July 12, 2014. SPS, intervenors and other parties have commenced settlement negotiations.

Next steps in the procedural schedule are as follows:

- Intervenor testimony — May 22, 2014;
- PUCT Staff testimony — May 29, 2014;
- Cross-rebuttal testimony — June 12, 2014;
- Rebuttal testimony — June 16, 2014;

- Evidentiary hearing — June 25, 2014; and
- A PUCT decision and implementation of final rates are anticipated in the third quarter of 2014.

Electric, Purchased Gas and Resource Adjustment Clauses

TCRF Rider — In November 2013, SPS filed with the PUCT to implement the TCRF for Texas retail customers. The requested increase in revenues is $13 million. The PUCT issued an order allowing the TCRF to go into effect on an interim basis effective Jan. 1, 2014. In April and May 2014, several parties including both intervenors and the PUCT Staff filed testimony recommending various reductions or modifications to the proposed TCRF.

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Next steps in the procedural schedule are as follows:

- SPS Rebuttal testimony — May 8, 2014; and
- Evidentiary hearings — May 15 - May 16, 2014.

Recently Concluded Regulatory Proceedings — New Mexico Public Regulation Commission (NMPRC)

SPS – New Mexico 2014 Electric Rate Case — In December 2012, SPS filed an electric rate case in New Mexico with the NMPRC for an increase in annual revenue of approximately $45.9 million effective in 2014. The rate filing was based on a 2014 FTY, a requested ROE of 10.65 percent, an electric rate base of $479.8 million and an equity ratio of 53.89 percent.

In September 2013, SPS filed rebuttal testimony, revising its requested rate increase to $32.5 million, based on updated information and an ROE of 10.25 percent. This reflects a base and fuel increase of $20.9 million, an increase of rider revenue of $12.1 million and a decrease to other of $0.5 million.

In March 2014, the NMPRC approved an overall increase of approximately $33.1 million. The increase includes: an ROE of 9.96 percent, an equity ratio of 53.89 percent, allowance of the prepaid pension asset in rate base of approximately $2.4 million, allowance of certain non-labor operating and maintenance escalations and recovery of approximately $18.1 million of renewable energy costs through rider revenue instead of base revenue. As a result of a change in the amount of fuel costs recovered through base rates, SPS will no longer be required to credit customers for $2.3 million through the fuel clause adjustment (FCA). Final rates were effective April 5, 2014. On April 25, 2014, the New Mexico Attorney General filed a request for rehearing. The rehearing request is pending with the NMPRC, which has until May 15, 2014 to grant or deny the request.

The following table summarizes the NMPRC's approval from SPS' revised request:

(Millions of Dollars)	NMPRC Approval
SPS revised request, September 2013	$32.5
Fuel clause adjustment credit — non-renewable energy costs	2.3
SPS revised request, fuel adjusted	34.8
ROE (9.96 percent)	(1.2)
Rate rider adjustment — renewable energy costs	6.0
Base rate reduction for rate rider — renewable energy costs	(6.0)
Other, net	(0.5)
Approved increase, March 2014	$33.1
Means of recovery:	
Base revenue	$12.7
Rider revenue	18.1
Fuel clause	2.3
	$33.1

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, 2013, appropriately represent, in all material respects, the current status of commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to Xcel

Energy’s financial position.

Purchased Power Agreements (PPAs)

Under certain PPAs, 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 PPAs create a variable interest in the associated independent power producing entity.

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The Xcel Energy utility subsidiaries had approximately 3,698 megawatts (MW) and 3,338 MW of capacity under long-term PPAs as of March 31, 2014 and Dec. 31, 2013, 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 March 31, 2014 and Dec. 31, 2013, 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)	March 31, 2014	Dec. 31, 2013
Guarantees issued and outstanding	$ 18.3	$ 19.4
Current exposure under these guarantees	0.3	0.3
Bonds with indemnity protection	32.4	32.1

Indemnification Agreements

In connection with the sale of certain Texas electric transmission assets to Sharyland Distribution and Transmission Services, LLC. in 2013, SPS agreed to indemnify the purchaser for losses arising out of any breach of the representations, warranties and covenants under the related asset purchase agreement and for losses arising out of certain other matters, including pre-closing liabilities. SPS' indemnification obligation is capped at $37.1 million, in the aggregate. The indemnification provisions for most representations and warranties expire in December 2014. The remaining representations and warranties, which relate to due organization and transaction authorization, survive indefinitely. As of March 31, 2014 and Dec. 31, 2013, SPS has recorded a $0.4 million liability related to this indemnity.

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. For the Sediments at the Ashland Site, the ROD preferred remedy is a hybrid remedy involving both dry excavation and wet conventional dredging methodologies (the Hybrid Remedy). The ROD also identifies the possibility of a wet conventional dredging only remedy for the Sediments (the Wet Dredge), contingent upon the completion of a successful Wet Dredge pilot study.

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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 settlement negotiations with NSP-Wisconsin, 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.

In October 2012, a settlement among the EPA, the Wisconsin Department of Natural Resources, 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 cleanup of the Phase I Project Area of $40 million. Demolition activities occurred at the Ashland site in 2013. The Final Design for the soil, including excavation and treatment, as well as containment wall remedies was submitted to the EPA in April 2014 and work is anticipated to begin in the second quarter of 2014. A Preliminary Design for the groundwater remedy was also submitted to the EPA in April 2014 and activities are expected to commence in 2015. Based on these updated designs, the updated cost estimate for the cleanup of the Phase I Project Area is approximately $51 million, of which $5 million has already been spent. The settlement also resolves claims by the federal, state and tribal trustees against NSP-Wisconsin for alleged natural resource damages at the Ashland site, including both the Phase I Project Area and the Sediments. As part of the settlement, NSP-Wisconsin has conveyed approximately 1,390 acres of land to the State of Wisconsin and tribal trustees. Fieldwork to address the Phase I Project Area at the Ashland site began at the end of 2012 and continues.

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay or perform the cleanup of the Sediments and what remedy will be implemented at the site to address the Sediments. In August and September 2013, NSP-Wisconsin performed field studies in the Sediments to gather more data about site conditions. The data from that investigation was received and reported to the EPA at the end of 2013. It is NSP-Wisconsin’s view that this data demonstrates the Hybrid Remedy is not safe or feasible to implement. The EPA’s ROD for the Ashland site includes estimates that the cost of the Hybrid Remedy 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. Also, in September 2013, the EPA requested NSP-Wisconsin consider re-submitting another proposal to perform a Wet Dredge pilot study for a portion of the Sediments. NSP-Wisconsin previously submitted a proposal for a Wet Dredge pilot study in 2011. In November 2013, NSP-Wisconsin submitted a revised Wet Dredge pilot study work plan proposal to the EPA. The EPA provided conditional approval of the Wet Dredge pilot study work plan in March 2014. NSP-Wisconsin is in the process of negotiating a final Administrative Order on Consent for the Wet Dredge pilot study for possible implementation of the pilot in late summer or early fall of 2014.

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 is scheduled for April 2015. Negotiations between the EPA, NSP-Wisconsin and several of the other PRPs regarding the PRPs’ fair share of the cleanup costs for the Ashland site are also ongoing.

At March 31, 2014 and Dec. 31, 2013, NSP-Wisconsin had recorded a liability of $115.2 million and $104.6 million, respectively, for the Ashland site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $33.4 million and $25.2 million, respectively, was considered a current liability. NSP-Wisconsin’s potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include the cleanup approach implemented for the

Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, potential contributions by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

NSP-Wisconsin has deferred the estimated site remediation costs, as a regulatory asset, based on an expectation that the Public Service Commission of Wisconsin (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.

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In the 2013 rate case decision, the PSCW recognized the potential magnitude of the future liability for the cleanup at the Ashland site and granted an exception to its existing policy at the request of NSP-Wisconsin. The elements of this exception include: (1) approval to begin recovery of estimated Phase 1 Project costs beginning on Jan. 1, 2013; (2) approval to amortize these estimated costs over a ten-year period; and (3) approval to apply a three percent carrying cost to the unamortized regulatory asset. In the 2014 rate case decision, the PSCW continued the cost recovery treatment established in the 2013 rate case, with respect to the 2013 and 2014 cleanup costs for the Phase I Project Area. The PSCW determined the timing of the cleanup of the Sediments was uncertain and declined NSP-Wisconsin's request to begin cost recovery for this portion of the cleanup in 2014 rates. However, the PSCW allowed NSP-Wisconsin to increase its 2014 amortization expense related to the cleanup by an additional $1.1 million to offset the need for a rate decrease for the natural gas utility. The cost recovery treatment granted by the PSCW in the 2013 and 2014 rate cases will help mitigate the rate impact to natural gas customers and the risk to NSP-Wisconsin from a longer amortization period.

Environmental Requirements

Water and waste
Federal Clean Water Act (CWA) 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. The final rule is now expected in September 2015. Under the current proposed rule, facilities would need to comply as soon as possible after July 2017 but no later than July 2022. The impact of this rule on Xcel Energy is uncertain at this time.

Federal CWA Section 316 (b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. In 2011, the EPA published the proposed rule that sets standards for minimization of aquatic species impingement, but leaves entrainment reduction requirements at the discretion of the permit writer and the regional EPA office. A final rule is anticipated in May 2014. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the uncertainty of the final regulatory requirements.

NSP-Minnesota submitted its Black Dog CWA compliance plan for the Minnesota Pollution Control Agency's (MPCA) review and approval in 2010. The MPCA is currently reviewing the proposal in consultation with the EPA.

Air
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 nitrous oxide (NOx) from utilities in the eastern half of the United States. For Xcel Energy, the rule would apply in Minnesota, Wisconsin and Texas. The CSAPR would set more stringent requirements than the proposed Clean Air Transport Rule and require plants in Texas to reduce their SO_2 and annual NOx emissions. The rule would also create an emissions trading program.

In August 2012, the United States 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 the EPA must continue administering the Clean Air Interstate Rule (CAIR) pending adoption of a valid replacement. In April 2014, the U.S. Supreme Court reversed and remanded the case to the D.C. Circuit. The Court held that the EPA's rule design did not violate the Clean Air Act (CAA) and that states had received adequate opportunity to develop their own plans. Because the D.C. Circuit overturned the CSAPR on two over-arching issues, there are many other issues the D.C. Circuit did not rule on that will now need to be considered on remand. Because it is not yet known how the litigation over the remaining issues will be resolved, it is not yet known what requirements may be imposed in the future, or their timing.

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 currently apply to Minnesota.

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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 2013 and plans to continue to purchase allowances in 2014 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 the second quarter of 2014. These installations will reduce or eliminate SPS' need to purchase NOx emission allowances. SPS had sufficient SO_2 allowances to comply with the CAIR in 2013 and has sufficient allowances through 2015. At March 31, 2014, 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.

Regional Haze Rules — In 2005, the EPA amended the best available retrofit technology (BART) requirements of its regional haze rules, 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. In their first regional haze state implementation plan (SIP), Colorado, Minnesota and Texas identified the Xcel Energy facilities that will have to reduce SO_2, NOx and PM emissions under BART and set emissions limits for those facilities.

PSCo
In 2011, the Colorado Air Quality Control Commission approved a SIP (the Colorado SIP) that included the CACJA emission reduction plan as satisfying regional haze requirements for the facilities included in the CACJA plan. In addition, the Colorado SIP included a BART determination for Comanche Units 1 and 2. The EPA approved the Colorado SIP in 2012. Emission controls at the Hayden and Pawnee plants are projected to cost $359.7 million and are expected to be installed between 2014 and 2017. PSCo anticipates these costs will be fully recoverable in rates.

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 it will challenge the BART determination made for Comanche Units 1 and 2. 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 intervened in the case. The 10th Circuit is anticipated to hear argument in January 2015, following completion of the briefs in October 2014.

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 the Colorado BART rule is inadequate to satisfy the 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 MPCA approved a SIP (the Minnesota SIP) and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NOx and scrubber upgrades for SO_2. The MPCA concluded SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The combustion controls have been installed and the scrubber upgrades, to be completed by January 2015, are underway. These emission controls are projected to cost approximately $50 million, of which $42.5 million has already been spent. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

After the CSAPR was adopted in 2011, the MPCA supplemented its Minnesota SIP, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 Minnesota SIP. In June 2012, 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. NSP-Minnesota and other regulated parties were denied intervention. In June 2013, the Court ordered this case to be held in abeyance until the U.S. Supreme Court decides on the CSAPR. It is not yet known how the U.S. Supreme Court’s April 2014 decision on the CSAPR will impact the Eighth Circuit’s proceedings on the Minnesota SIP. If this litigation ultimately results in further EPA proceedings concerning the Minnesota SIP, such proceedings may consider whether SCRs should be required for Sherco Units 1 and 2.

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SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas 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 U.S. Supreme Court's April 2014 decision on the CSAPR may impact the EPA's approval of the Texas SIP.

Reasonably Attributable Visibility Impairment (RAVI) — Additional visibility rules relate to a program called the 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 has stated it 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 the EPA has failed to perform a nondiscretionary duty to determine BART for Sherco Units 1 and 2 under the RAVI program. The EPA filed an answer denying the allegations. 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. Oral arguments were held in March 2014. The court is expected to issue an opinion in the next few months.

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.

Employment, Tort and Commercial Litigation

Merricourt Wind Project Litigation — In April 2011, NSP-Minnesota terminated its agreements with enXco Development Corporation (enXco) for the development of a 150 MW wind project in southeastern North Dakota. NSP-Minnesota's decision to terminate the agreements was based in large part on the adverse impact this project could have on endangered or threatened species protected by federal law and the uncertainty in cost and timing in mitigating this impact. NSP-Minnesota also terminated the agreements due to enXco's nonperformance of certain other conditions, including failure to obtain a Certificate of Site Compatibility and the failure to close on the contracts by an agreed upon date of March 31, 2011. NSP-Minnesota recorded a $101 million deposit in the first quarter of 2011, which was collected in April 2011. In May 2011, NSP-Minnesota filed a declaratory judgment action in the U.S. District Court in Minnesota to obtain a determination that it acted properly in terminating the agreements. enXco also filed a separate lawsuit in the same court seeking approximately $240 million for an alleged breach of contract.

NSP-Minnesota believes enXco's lawsuit is without merit. In October 2012, NSP-Minnesota filed a motion for summary judgment. In April 2013, the U.S. District Court granted NSP-Minnesota's motion and entered judgment in its favor. In April 2013, enXco filed a notice of appeal to the Eighth Circuit. It is uncertain when the Eighth Circuit will decide this appeal. Although Xcel Energy believes the likelihood of loss is remote based on existing case law and the U.S. District Court's April 2013 decision, it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. No accrual has been recorded for this matter.

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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, including a pending appeal by SPS in the Fifth Circuit Court of Appeals. SPS believes the likelihood of loss in these lawsuits and proceedings is remote based primarily on existing case law and while it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome, SPS believes such loss would not be material based upon its belief that it would be permitted to recover such costs, if needed, through its various fuel clause mechanisms. No accrual has been recorded for this matter.

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

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

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

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

A hearing in this case was held before a FERC ALJ and concluded in October 2013. On March 28, 2014, the FERC ALJ issued an initial decision which rejected all of the City of Seattle's claims against PSCo and other respondents. With respect to the period Jan. 1, 2000 through Dec. 24, 2000, the FERC ALJ rejected the City of Seattle's assertion that any of the sales made to the City of Seattle resulted in an excessive burden to the City of Seattle, the applicable legal standard for the City of Seattle's challenges during this period. With respect to the period Dec. 25, 2000 through June 20, 2001, the FERC ALJ concluded that the City of Seattle had failed to establish a causal link between any contracts and any claimed unlawful market activity, the standard required by the FERC in its remand order. The City of Seattle may contest the FERC ALJ's initial decision by filing a brief on exceptions to the FERC.

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

Biomass Fuel Handling Reimbursement — NSP-Minnesota has a PPA through which it procures energy from Fibrominn, LLC (Fibrominn). Under this agreement, NSP-Minnesota is charged for certain costs of transporting biomass fuels that are delivered to Fibrominn's generation facility. Fibrominn has demanded that NSP-Minnesota provide additional cost reimbursement for the period from September 2007 through March 2014, totaling approximately $19 million. NSP-Minnesota has evaluated Fibrominn's claim and based on the terms of the PPA with Fibrominn and its current understanding of the facts, NSP-Minnesota disputes the validity of Fibrominn's claim, on the ground that, among other things, it seeks to impose contractual obligations on NSP-Minnesota that are neither supported by the terms nor the intent of the PPA. NSP-Minnesota has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, NSP-Minnesota is currently unable to determine the amount of reasonably possible loss. If a loss were sustained, NSP-Minnesota would attempt to recover these fuel-related costs. 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. In January 2014, the United States proposed, and NSP-Minnesota accepted, an extension to the settlement agreement which will allow NSP-Minnesota to recover spent fuel storage costs through 2016. The extension does not address costs for used fuel storage after 2016; such costs could be the subject of future litigation. NSP-Minnesota has received a total of $181.9 million of settlement proceeds as of March 31, 2014. Amounts received from the installments will be subsequently credited to customers, except for approved reductions such as legal costs and amounts set aside to be credited through another regulatory mechanism.

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 March 31, 2014	Twelve Months Ended Dec. 31, 2013
Borrowing limit	$2,450	$2,450
Amount outstanding at period end	765	759
Average amount outstanding	925	481
Maximum amount outstanding	1,200	1,160
Weighted average interest rate, computed on a daily basis	0.31 %	0.31 %
Weighted average interest rate at period end	0.33	0.25

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 March 31, 2014 and Dec. 31, 2013, there were $46.3 million and $47.8 million of letters of credit outstanding, respectively, under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

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 March 31, 2014, 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	$487.0	$313.0
PSCo	700.0	6.5	693.5
NSP-Minnesota	500.0	148.9	351.1
SPS	300.0	90.0	210.0
NSP-Wisconsin	150.0	79.0	71.0
Total	$2,450.0	$811.4	$1,638.6

[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 March 31, 2014 and Dec. 31, 2013.

During the second quarter of 2014, Xcel Energy plans to work with its bank group to amend and extend the existing revolving credit agreements for Xcel Energy Inc. and each of the regulated subsidiaries.

Long-Term Borrowings and Other Financing Instruments

PSCo — In March 2014, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044.

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. During the three months ended

March 31, 2014, Xcel Energy Inc. issued 2.1 million shares of common stock through this program and received cash proceeds of $62 million, net of $1 million in fees and commissions. During the year ended Dec. 31, 2013, 7.7 million shares of common stock were issued under the program and Xcel Energy Inc. received cash proceeds of $223 million, net of $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.

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Xcel Energy Inc. had commitments not recognized on the consolidated balance sheet at March 31, 2014 to sell 0.5 million shares of common stock under sales transactions entered into during the last three trading days of March 2014. Subsequent to March 31, 2014, Xcel Energy Inc. issued shares to settle these transactions in exchange for cash proceeds of $16 million, net of $0.2 million in fees and commissions.

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 models using highly observable inputs.

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

Specific valuation methods include the following:

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

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on Xcel Energy's evaluation of its redemption rights, 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 transmission congestion instruments purchased from Midcontinent Independent Transmission System Operator, Inc. (MISO), PJM Interconnection, LLC (PJM), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool, Inc. (SPP) and New York Independent System Operator, generally referred to as financial transmission rights (FTRs). Electric commodity derivatives held by SPS include FTRs purchased from SPP. FTRs purchased from a regional transmission organization (RTO) 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. The 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 and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, 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. NSP-Minnesota uses the MPUC approved 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 $258.6 million and $240.3 million at March 31, 2014 and Dec. 31, 2013, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $45.8 million and $58.5 million at March 31, 2014 and Dec. 31, 2013, 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 March 31, 2014 and Dec. 31, 2013:

	March 31, 2014				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$15,854	$15,854	$—	$—	$15,854
Commingled funds	476,011	—	483,409	—	483,409
International equity funds	78,812	—	82,710	—	82,710
Private equity investments	60,912	—	—	73,801	73,801
Real estate	49,224	—	—	62,954	62,954
Debt securities:					
Government securities	34,176	—	28,822	—	28,822
U.S. corporate bonds	78,362	—	81,827	—	81,827
International corporate bonds	15,223	—	15,685	—	15,685
Municipal bonds	261,106	—	260,044	—	260,044
Equity securities:					
Common stock	380,896	558,289	—	—	558,289
Total	$1,450,576	$574,143	$952,497	$136,755	$1,663,395

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $86.3 million of equity investments in unconsolidated subsidiaries and $43.4 million of miscellaneous investments.

	Dec. 31, 2013				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$33,281	$33,281	$—	$—	$33,281
Commingled funds	457,986	—	452,227	—	452,227
International equity funds	78,812	—	81,671	—	81,671
Private equity investments	52,143	—	—	62,696	62,696
Real estate	45,564	—	—	57,368	57,368
Debt securities:					
Government securities	34,304	—	27,628	—	27,628
U.S. corporate bonds	80,275	—	83,538	—	83,538
International corporate bonds	15,025	—	15,358	—	15,358
Municipal bonds	241,112	—	232,016	—	232,016
Equity securities:					
Common stock	406,695	581,243	—	—	581,243
Total	$1,445,197	$614,524	$892,438	$120,064	$1,627,026

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $87.1 million of equity investments in unconsolidated subsidiaries and $41.9 million of miscellaneous investments.

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The following tables present the changes in Level 3 nuclear decommissioning fund investments for the three months ended March 31, 2014 and 2013:

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Assets	Transfers Out of Level 3	March 31, 2014
Private equity investments	$62,696	$8,769	$—	$2,336	$—	$73,801
Real estate	57,368	3,660	—	1,926	—	62,954
Total	$120,064	$12,429	$—	$4,262	$—	$136,755

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Assets	Transfers Out of Level 3[(a)]	March 31, 2013
Private equity investments	$33,250	$1,256	$—	$—	$—	$34,506
Real estate	39,074	4,786	(4,299)	845	—	40,406
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	$104,600	$6,042	$(4,299)	$845	$(32,276)	$74,912

(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.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at March 31, 2014:

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$—	$—	$28,822	$28,822
U.S. corporate bonds	311	15,816	64,341	1,359	81,827
International corporate bonds	—	3,762	11,923	—	15,685
Municipal bonds	3,088	25,410	38,770	192,776	260,044
Debt securities	$3,399	$44,988	$115,034	$222,957	$386,378

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 March 31, 2014, 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, FTRs and vehicle fuel.

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At March 31, 2014, 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 months ended March 31, 2014 and 2013.

At March 31, 2014, 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.

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 March 31, 2014 and Dec. 31, 2013:

(Amounts in Thousands) [a][b]	March 31, 2014	Dec. 31, 2013
Megawatt hours of electricity	32,453	58,423
Million British thermal units of natural gas	—	9,854
Gallons of vehicle fuel	432	482

[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.

The following tables detail the impact of derivative activity during the three months ended March 31, 2014 and 2013, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended March 31, 2014				
	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	$—	$—	$946 [a]	$—	$—
Vehicle fuel and other commodity	(12)	—	(28) [b]	—	—
Total	$(12)	$—	$918	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$(2,253) [c]
Electric commodity	—	3,527	—	(20,696) [d]	—
Natural gas commodity	—	18,506	—	(18,840) [e]	(5,302) [e]
Total	$—	$22,033	$—	$(39,536)	$(7,555)

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	Three Months Ended March 31, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$1,150 (a)	$—	$—
Vehicle fuel and other commodity	25	—	(26) (b)	—	—
Total	$25	$—	$1,124	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$2,776 (c)
Electric commodity	—	6,419	—	(15,229) (d)	—
Natural gas commodity	—	54	—	9 (e)	16 (e)
Total	$—	$6,473	$—	$(15,220)	$2,792

(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 gain and loss amounts 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 three months ended March 31, 2014 and 2013 included immaterial 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. The remaining derivative settlement gains and losses for the three months ended March 31, 2014 and 2013 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These gains and losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset or liability, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the three months ended March 31, 2014 and 2013. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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 and transmission activities. At March 31, 2014, four of Xcel Energy's 10 most significant counterparties for these activities, comprising $41.2 million or 15 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's Ratings Services, Moody's Investor Services (Moody's) or Fitch Ratings. The remaining six significant counterparties, comprising $79.2 million or 29 percent of this credit exposure, were not rated by these agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. All 10 of these significant counterparties are RTOs, municipal or cooperative electric entities or other utilities.

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 $1.1 million and $1.4 million gross liability position on the consolidated balance sheets at March 31, 2014 and Dec. 31, 2013, respectively, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle applicable outstanding contracts, including other contracts subject to master netting agreements, which would have resulted in payments of $1.1 million and $1.4 million at March 31, 2014 and Dec. 31, 2013, respectively. At March 31, 2014 and Dec. 31, 2013, there was no collateral posted on these specific contracts.

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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 March 31, 2014 and Dec. 31, 2013.

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 March 31, 2014:

	March 31, 2014					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$58	$—	$58	$—	$58
Other derivative instruments:						
Commodity trading	—	20,979	944	21,923	(6,467)	15,456
Electric commodity	—	—	26,640	26,640	(4,907)	21,733
Total current derivative assets	$—	$21,037	$27,584	$48,621	$(11,374)	37,247
PPAs [a]						33,028
Current derivative instruments						$70,275
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$18	$—	$18	$—	$18
Other derivative instruments:						
Commodity trading	—	15,718	1,932	17,650	(407)	17,243
Total noncurrent derivative assets	$—	$15,736	$1,932	$17,668	$(407)	17,261
PPAs [a]						50,252
Noncurrent derivative instruments						$67,513
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$11,946	$392	$12,338	$(12,338)	$—
Electric commodity	—	—	4,907	4,907	(4,907)	—
Total current derivative liabilities	$—	$11,946	$5,299	$17,245	$(17,245)	—
PPAs [a]						22,358
Current derivative instruments						$22,358
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$1,707	$—	$1,707	$(1,015)	$692
Total noncurrent derivative liabilities	$—	$1,707	$—	$1,707	$(1,015)	692
PPAs [a]						198,886
Noncurrent derivative instruments						$199,578

[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 PPAs 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 March 31, 2014. At March 31, 2014, derivative assets and liabilities include obligations to return cash collateral of $0.1 million and rights to reclaim cash collateral of $6.5 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2013:

(Thousands of Dollars)	Dec. 31, 2013 Fair Value 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	$—	$88	$—	$88	$—	$88
Other derivative instruments:						
Commodity trading	—	20,610	1,167	21,777	(7,994)	13,783
Electric commodity	—	—	47,112	47,112	(8,210)	38,902
Natural gas commodity	—	5,906	—	5,906	—	5,906
Total current derivative assets	$—	$26,604	$48,279	$74,883	$(16,204)	58,679
PPAs [a]						33,028
Current derivative instruments						$91,707
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$29	$—	$29	$(16)	$13
Other derivative instruments:						
Commodity trading	—	32,074	3,395	35,469	(9,071)	26,398
Total noncurrent derivative assets	$—	$32,103	$3,395	$35,498	$(9,087)	26,411
PPAs [a]						58,431
Noncurrent derivative instruments						$84,842
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$10,546	$1,804	$12,350	$(12,002)	$348
Electric commodity	—	—	8,210	8,210	(8,210)	—
Total current derivative liabilities	$—	$10,546	$10,014	$20,560	$(20,212)	348
PPAs [a]						23,034
Current derivative instruments						$23,382
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$14,382	$—	$14,382	$(9,087)	$5,295
Total noncurrent derivative liabilities	$—	$14,382	$—	$14,382	$(9,087)	5,295
PPAs [a]						203,929
Noncurrent derivative instruments						$209,224

(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 PPAs 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, 2013. At Dec. 31, 2013, derivative assets and liabilities include obligations to return cash collateral of $0.2 million and rights to reclaim cash collateral of $4.2 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents the changes in Level 3 commodity derivatives for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31	
(Thousands of Dollars)	2014	2013
Balance at Jan. 1	$41,660	$16,649
Purchases	1,056	—
Settlements	(53,809)	(12,449)
Net transactions recorded during the period:		
Gains (losses) recognized in earnings [(a)]	999	(62)
Gains recognized as regulatory assets and liabilities	34,311	3,504
Balance at March 31	$24,217	$7,642

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

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three months ended March 31, 2014 and 2013.

Fair Value of Long-Term Debt

As of March 31, 2014 and Dec. 31, 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	March 31, 2014		Dec. 31, 2013	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$11,487,452	$12,511,410	$11,191,517	$11,878,643

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 March 31, 2014 and Dec. 31, 2013, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

9. Other Income, Net

Other income, net consisted of the following:

	Three Months Ended March 31	
(Thousands of Dollars)	2014	2013
Interest income	$3,893	$4,806
Other nonoperating income	1,116	1,255
Insurance policy expense	(1,808)	(2,139)
Other income, net	$3,201	$3,922

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.

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- 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 $86.3 million and $87.1 million as of March 31, 2014 and Dec. 31, 2013, 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 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)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2014					
Operating revenues from external customers	$2,301,710	$879,688	$21,206	$—	$3,202,604
Intersegment revenues	353	3,252	—	(3,605)	—
Total revenues	$2,302,063	$882,940	$21,206	$(3,605)	$3,202,604
Net income (loss)	$185,433	$77,336	$(1,548)	$—	$261,221

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2013					
Operating revenues from external customers	$2,092,196	$669,596	$21,057	$—	$2,782,849
Intersegment revenues	301	500	—	(801)	—
Total revenues	$2,092,497	$670,096	$21,057	$(801)	$2,782,849
Net income (loss)	$174,106	$64,910	$(2,446)	$—	$236,570

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 in share-based compensation arrangements.

Common stock equivalents causing dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards and time based employer matching contributions to certain 401(k) plan participants. In October 2013, Xcel Energy determined that it would settle the 2013 401(k) employer matching contributions in cash instead of common stock for substantially all of its employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements.

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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.

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

- 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.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

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

	Three Months Ended March 31, 2014			Three Months Ended March 31, 2013		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$261,221			$236,570		
Basic EPS:						
Earnings available to common shareholders	261,221	499,523	$0.52	236,570	489,781	$0.48
Effect of dilutive securities:						
Time based equity awards	—	223		—	750	
Diluted EPS:						
Earnings available to common shareholders	$261,221	499,746	$0.52	$236,570	490,531	$0.48

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended March 31			
	2014	2013	2014	2013
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$22,086	$24,071	$864	$1,182
Interest cost	39,155	35,172	8,507	8,417
Expected return on plan assets	(51,801)	(49,613)	(8,489)	(8,253)
Amortization of transition obligation	—	—	—	206
Amortization of prior service (credit) cost	(437)	1,468	(2,672)	(2,438)
Amortization of net loss	29,191	36,038	2,935	5,646
Net periodic benefit cost	38,194	47,136	1,145	4,760
Costs not recognized due to the effects of regulation	(7,052)	(7,847)	—	—
Net benefit cost recognized for financial reporting	$31,142	$39,289	$1,145	$4,760

In January 2014, contributions of $130.0 million were made across three of Xcel Energy’s pension plans. Xcel Energy does not expect additional pension contributions during 2014.

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13. Other Comprehensive Income

Changes in accumulated other comprehensive gain (loss), net of tax, for the three months ended March 31, 2014 and 2013 were as follows:

(Thousands of Dollars)	Three Months Ended March 31, 2014 Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive gain (loss) at Jan. 1	$(59,753)	$77	$(46,599)	$(106,275)
Other comprehensive gain (loss) before reclassifications	(7)	38	—	31
Losses reclassified from net accumulated other comprehensive loss	560	—	864	1,424
Net current period other comprehensive income	553	38	864	1,455
Accumulated other comprehensive gain (loss) at March 31	$(59,200)	$115	$(45,735)	$(104,820)

(Thousands of Dollars)	Three Months Ended March 31, 2013 Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(61,241)	$(99)	$(51,313)	$(112,653)
Other comprehensive gain (loss) before reclassifications	13	(36)	—	(23)
Gains reclassified from net accumulated other comprehensive loss	(305)	—	(639)	(944)
Net current period other comprehensive loss	(292)	(36)	(639)	(967)
Accumulated other comprehensive loss at March 31	$(61,533)	$(135)	$(51,952)	$(113,620)

Reclassifications from accumulated other comprehensive loss for the three months ended March 31, 2014 and 2013 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
(Gains) losses on cash flow hedges:		
Interest rate derivatives	$946 (a)	$1,150 (a)
Vehicle fuel derivatives	(28) (b)	(26) (b)
Total, pre-tax	918	1,124
Tax benefit	(358)	(1,429)
Total, net of tax	560	(305)
Defined benefit pension and postretirement (gains) losses:		
Amortization of net loss	1,500 (c)	1,769 (c)
Prior service (credit) cost	(86) (c)	93 (c)
Transition obligation	— (c)	2 (c)

Total, pre-tax	1,414	1,864
Tax benefit	(550)	(2,503)
Total, net of tax	864	(639)
Total amounts reclassified, net of tax	$1,424	$(944)

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 12 for details regarding these benefit plans.

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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.

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 2014 earnings per share guidance and assumptions, are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Continuing Operations in Item 7 of Xcel Energy Inc.'s Form 10-K for the year ended Dec. 31, 2013; 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, 2013, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

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. Ongoing diluted EPS for Xcel Energy and by subsidiary is a financial measure not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period.

We use this non-GAAP financial measure to evaluate and provide details of earnings results. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

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Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended March 31	
Diluted Earnings (Loss) Per Share	2014	2013
PSCo	$0.24	$0.24
NSP-Minnesota	0.21	0.21
NSP-Wisconsin	0.05	0.04
SPS	0.04	0.02
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility	0.55	0.52
Xcel Energy Inc. and other costs	(0.03)	(0.04)
GAAP diluted EPS	$0.52	$0.48

Xcel Energy — Overall, earnings increased $0.04 per share for the first quarter of 2014. First quarter 2014 earnings were higher due to increased electric and natural gas margins primarily due to colder weather at NSP-Minnesota and NSP-Wisconsin and rate increases in several jurisdictions. These positive factors were partially offset by increased operating and maintenance expenses and property taxes.

PSCo — PSCo’s earnings were flat for the first quarter of 2014. Higher electric and natural gas rates and sales growth were offset by increased property taxes, depreciation, and accruals associated with electric earnings test refund obligations.

NSP-Minnesota — NSP-Minnesota’s earnings were flat for the first quarter of 2014. Colder weather and interim electric rate increases in Minnesota (subject to refund) and North Dakota were offset by higher O&M expenses and lower allowance for funds used during construction (AFUDC). In addition, results for the first quarter of 2013 reflect interim rates in Minnesota, which were recorded at a level higher than the final rates implemented later in 2013.

NSP-Wisconsin — NSP-Wisconsin’s earnings increased $0.01 per share for the first quarter of 2014. Higher electric and natural gas margins, due to colder weather and an electric rate increase effective in January 2014, were partially offset by higher O&M expenses.

SPS — SPS’ earnings increased $0.02 per share for the first quarter of 2014. The positive impact of higher electric rates and interim transmission rider revenue in Texas were partially offset by increased O&M expenses.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2014 diluted EPS compared with the same period in 2013. See further discussion below.

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
2013 GAAP diluted EPS	$0.48
Components of change — 2014 vs. 2013	
Higher electric margins	0.08
Higher natural gas margins	0.03
Higher O&M expenses	(0.04)

Higher conservation and demand side management (DSM) program expenses	(0.02)
Dilution from equity issued through the at-the-market program, direct stock purchase plan and benefit plans	(0.01)
Higher taxes (other than income taxes)	(0.01)
Other, net	0.01
2014 GAAP diluted EPS	$0.52

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

	Three Months Ended March 31	
(Millions of Dollars)	2014	2013
GAAP income (loss) by segment		
Regulated electric income	$185.4	$174.1
Regulated natural gas income	77.3	64.9
Other income [a]	11.4	16.2
Xcel Energy Inc. and other costs [a]	(12.9)	(18.6)
Total net income	$261.2	$236.6

	Three Months Ended March 31	
Contributions to Diluted Earnings (Loss) Per Share	2014	2013
GAAP earnings (loss) by segment		
Regulated electric	$0.37	$0.36
Regulated natural gas	0.16	0.13
Other [a]	0.02	0.03
Xcel Energy Inc. and other costs [a]	(0.03)	(0.04)
Total diluted EPS	$0.52	$0.48

[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.

There was no impact on sales in the first quarter of 2014 due to THI or CDD. The percentage increase in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
HDD	14.1 %	3.6 %	9.3 %

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

	Three Months Ended March 31		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
Retail electric	$0.031	$0.004	$0.027
Firm natural gas	0.018	0.009	0.009
Total	$0.049	$0.013	$0.036

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

	Three Months Ended March 31				
	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	Xcel Energy
Actual					
Electric residential	5.8 %	8.2 %	1.1 %	9.6 %	4.8 %
Electric commercial and industrial [a]	2.8	6.4	1.4	4.5	3.0
Total retail electric sales	3.7	7.0	1.5	5.4	3.6
Firm natural gas sales [b]	17.2	19.8	(0.4)	N/A	6.5

	Three Months Ended March 31				
	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	Xcel Energy
Weather Normalized					
Electric residential	0.5 %	0.6 %	1.3 %	2.8 %	1.1 %
Electric commercial and industrial [a]	1.5	4.6	1.1	4.5	2.3
Total retail electric sales	1.2	3.3	1.4	4.0	2.0
Firm natural gas sales [b]	2.6	1.2	4.6	N/A	3.7

(a) The growth in the NSP-Wisconsin electric commercial and industrial (C&I) class is primarily driven by increases in the manufacturing and energy sectors. The growth in the SPS electric C&I class is primarily the result of continued rapid expansion of oilfield development.

(b) As normal weather conditions are typically defined as a 30-year average of actual historical weather conditions, significant weather fluctuations in periods of low demand may result in large percentage changes on small volumes. Extreme weather variations and additional factors such as windchill and cloud cover may not be fully reflected.

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 March 31	
(Millions of Dollars)	2014	2013
Electric revenues	$2,302	$2,092
Electric fuel and purchased power	(1,067)	(925)
Electric margin	$1,235	$1,167

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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 March 31 2014 vs. 2013
Fuel and purchased power cost recovery	$101
Retail rate increases [a]	38
Transmission revenue	26
Trading	23
Estimated impact of weather	21
Conservation and DSM program revenues (offset by expenses)	13
Retail sales growth, excluding weather impact	12
PSCo earnings test refund obligations	(11)
Other, net	(13)
Total increase in electric revenues	$210

Electric Margin

(Millions of Dollars)	Three Months Ended March 31 2014 vs. 2013
Retail rate increases [a]	$38
Estimated impact of weather	21
Conservation and DSM program revenues (offset by expenses)	13
Retail sales growth, excluding weather impact	12
Transmission revenue, net of costs	12
PSCo earnings test refund obligations	(11)
Other, net	(17)
Total increase in electric margin	$68

(a) The retail rate increases include final rates in Texas, Wisconsin, Colorado and North Dakota, and interim rates in Minnesota (subject to refund). See Note 5 to the consolidated financial statements for further discussion of rates and regulation.

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 March 31	
(Millions of Dollars)	2014	2013
Natural gas revenues	$880	$670
Cost of natural gas sold and transported	(624)	(439)
Natural gas margin	$256	$231

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 March 31 2014 vs. 2013
Purchased natural gas adjustment clause recovery	$183
Retail rate increase, net of refund (Colorado)	9
Estimated impact of weather	7
PSIA rider (Colorado)	4
Retail sales growth	3
Other, net	4
Total increase in natural gas revenues	$210

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Natural Gas Margin

(Millions of Dollars)	Three Months Ended March 31 2014 vs. 2013
Retail rate increase, net of refund (Colorado)	$9
Estimated impact of weather	7
PSIA rider (Colorado), partially offset in O&M expenses	4
Retail sales growth	3
Other, net	2
Total increase in natural gas margin	$25

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $30.9 million, or 5.8 percent, for the first quarter of 2014 compared with the same period in 2013. The increase in O&M expenses for the first quarter reflects timing issues and overall increases in expense levels, as summarized in the table below. Xcel Energy continues to anticipate annual O&M expenses will increase 2 percent to 3 percent for 2014.

(Millions of Dollars)	Three Months Ended March 31 2014 vs. 2013
Nuclear plant operations and amortization	$12
Electric and gas distribution expenses	10
Transmission costs	2
Other, net	7
Total increase in O&M expenses	$31

- Nuclear cost increases were related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants;
- Electric and gas distribution expenses were primarily driven by increased maintenance activities attributable to weather and storm related costs, vegetation management, repairs and amounts related to pipeline system integrity; and
- Transmission costs were primarily due to higher substation maintenance expenditures.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $13.5 million, or 21.1 percent, for the first quarter of 2014 compared with the same period in 2013. The higher expenses were primarily attributable to higher rider rates and higher volume for recovery of electric conservation program expenses at NSP-Minnesota. Conservation costs are recovered from customers and expensed on a kilowatt hour basis, so increased sales due to cold winter temperatures or hot summer temperatures will increase revenue and expense. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization decreased $2.8 million, or 1.1 percent, for the first quarter of 2014 compared with the same period in 2013. As part of the 2013 and pending 2014 Minnesota electric rate cases, depreciation expense during the first quarter of 2014 was reduced by $28.3 million, and reflects the acceleration of the amortization of the excess depreciation reserve. This decrease was partially offset by depreciation and amortization associated with normal system expansion. See Note 5 to the consolidated financial statements for further discussion of the Minnesota 2014 Multi-Year Electric Rate Case.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $11.3 million, or 9.9 percent, for the first quarter of 2014 compared with the same period in 2013. The increase was due to higher property taxes primarily in Minnesota and Colorado.

AFUDC, Equity and Debt — AFUDC increased $2.9 million for the first quarter of 2014 compared with the same period in 2013. The increase was primarily due to construction related to the CACJA and the expansion of transmission facilities.

Interest Charges — Interest charges decreased $0.5 million, or 0.4 percent, for the first quarter of 2014 compared with the same period in 2013. The decrease was primarily due to refinancings at lower interest rates. This was partially offset by higher long-term debt levels.

Income Taxes — Income tax expense increased $17.3 million for the first quarter of 2014 compared with the same period in 2013. The increase in income tax expense was primarily due to higher pretax earnings in 2014.

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The ETR was 34.2 percent for the first quarter of 2014 compared with 33.4 percent for the same period in 2013. The lower ETR for 2013 was primarily due to the recognition of research and experimentation credits in 2013 due to the passage of the American Taxpayer Relief Act and a tax benefit for a carryback claim related to 2013. These were partially offset by the successful resolution of a 2010-2011 IRS audit issue in 2014.

Public Utility Regulation

NSP-Minnesota

NSP System Resource Plans — In March 2013, the MPUC approved NSP-Minnesota's Resource Plan and ordered a competitive acquisition process with the goal of adding approximately 500 MW of generation to the NSP System by 2019.

In September 2013, NSP-Minnesota recommended a self-build, 215 MW natural gas combustion turbine at its Black Dog site and a PPA with either Calpine's Mankato combined cycle natural gas project or Invenergy's Cannon Falls combustion turbine natural gas project. In October 2013, the DOC recommended the MPUC approve NSP-Minnesota's proposal.

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

At a hearing in March 2014, the MPUC appeared to favor the Geronimo Energy (solar) proposal and instructed NSP-Minnesota to negotiate PPAs. In addition, the MPUC directed NSP-Minnesota to negotiate PPAs with Calpine (combined cycle) and Invenergy (combustion turbine) and develop pricing for the Black Dog site. NSP-Minnesota is awaiting a written order. A MPUC decision is anticipated in late 2014. The next Minnesota resource plan is expected to be filed in January 2015.

In early 2013, NSP-Minnesota also issued a request for proposal (RFP) for wind generation and subsequently sought commission approval for four wind projects.

- A 200 MW ownership project for the Pleasant Valley wind farm in Minnesota;
- A 150 MW ownership project for the Border Winds wind farm in North Dakota;
- A 200 MW PPA with Geronimo Energy, LLC for the Odell wind farm in Minnesota; and
- A 200 MW PPA with Geronimo Energy, LLC for the Courtenay wind farm in North Dakota.

In October 2013, the MPUC approved the four wind projects. In 2014, the NDPSC approved the prudence of the Border Winds project as part of the rate case settlement and determined it will address the Pleasant Valley project at a later date. The feasibility of the Border Winds and Pleasant Valley projects are also dependent on the finalization of estimated transmission costs, which MISO is expected to determine in 2014.

On April 22, 2014, NSP-Minnesota filed a RFP for up to 100 MW's of solar generation resources. Proposals will be accepted through June 2014. NSP-Minnesota will evaluate bids from that time until mid-August and anticipates filing selected bids with the MPUC in October 2014.

CapX2020 — In 2009, the MPUC granted CONs 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 five major CapX2020 transmission projects below is $2.1 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.2 billion of the total investment. As of March 31, 2014, a total of $715 million has been spent on the five CapX2020 transmission projects.

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. All avenues of appeal for the grant of project permits have now been exhausted. In July 2013, the FERC denied a complaint filed by two citizen groups in March 2013 against the project. Construction on the project started in Minnesota in January 2013 and the project is expected to go into service in 2015.

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Monticello, Minn. to Fargo, N.D. 345 KV transmission line
In December 2011, the Monticello, Minn. to St. Cloud, Minn. portion of the Monticello, Minn. to Fargo, N.D. project was placed in service. The MPUC issued a route permit for the Minnesota portion of the St. Cloud, Minn. to Fargo, N.D. section in June 2011. Construction started on the Minnesota portion of the St. Cloud, Minn. to Fargo, N.D. segment in January 2012. In April 2014, the St. Cloud, Minn. to Alexandria, Minn. portion of the project was placed in service. The NDPSC granted a CPCN in January 2011 and a certificate of corridor compatibility and route permit for the portion of the line in North Dakota in September 2012. In January 2013, construction started on the project in North Dakota. The final phase of the project, Alexandria, Minn. to Fargo, N.D. is expected to go into service in 2015.

Brookings County, S.D. to Hampton, Minn. 345 KV transmission line
The MPUC route permit approvals for the Minnesota segments were obtained in 2010 and 2011. In June 2011, the South Dakota Public Utilities Commission (SDPUC) approved a facility permit for the South Dakota segment. In December 2011, MISO granted the final approval of the project as a multi-value project (MVP). Construction started on the project in Minnesota in May 2012. The project is expected to go fully into service in 2015, although segments will be placed in service as they are completed.

Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line
The Bemidji, Minn. to Grand Rapids, Minn. line was placed in service in September 2012.

Big Stone South to Brookings County, S.D. 345 KV transmission line
In December 2011, MISO granted final approval of the project as a MVP. In March 2014, the SDPUC approved a permit for construction of the project’s southern portion. Construction is anticipated to begin in late 2015, with completion in 2017.

Minnesota Solar Legislation — In May 2013, a law was passed requiring that 1.5 percent of a public utility’s total electric retail sales to retail customers be generated using solar energy by 2020. Of the 1.5 percent, 10 percent must come from systems sized less than 20 kilowatts. The legislation also authorized NSP-Minnesota to offer two new solar programs: a community solar garden program that will provide bill credits to participating solar garden subscribers and a new solar energy incentive program for solar energy systems equal to or less than 20 kilowatts that authorizes the spending of $5.0 million over five years for production incentive payments. NSP-Minnesota is continuing to work toward bringing solar energy generation on line in support of these solar programs and legislative requirements.
NSP-Minnesota submitted its proposal for a community solar garden program to the MPUC in September 2013. The legislation also provides for an alternative tariff based on a distributed solar value or “Value of Solar” methodology. In January 2014, the DOC filed a Value of Solar methodology with the MPUC in compliance with legislative requirements. In March 2014, the MPUC approved the DOC’s Value of Solar methodology. On April 21, 2014, NSP-Minnesota filed a motion to reconsider the Value of Solar methodology.

Minneapolis, Minn. Franchise Agreement — The franchise agreement with the City of Minneapolis expires on Dec. 31, 2014. In March 2014, the City of Minneapolis disclosed the findings of a $250,000 exploratory study aimed at examining the various paths the City of Minneapolis could take to achieve its energy goals, including 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. The study concluded that the most viable current alternatives for the City of Minneapolis to achieve its goals are to simultaneously negotiate enhanced franchise agreements of shorter duration and enter into clean energy partnership agreements with the utilities. One conclusion of the study was that municipalization would be a very costly and lengthy process for the City of Minneapolis. NSP-Minnesota continues to meet with the City of Minneapolis and is engaged in on-going conversations to explore mutually agreeable outcomes.

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, 2013 for further discussion regarding the nuclear generating plants.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants. The event at the nuclear generating plant in Fukushima, Japan in 2011 has resulted in additional regulation regarding plant readiness to safely manage severe events, which is expected to require additional capital expenditures and operating expenses.

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

In June 2013, the NRC issued a revised order with regard to reliable hardened containment vents. The revised order added severe accident conditions under which the existing hardened vent which comes off of the wet portion of the containment needs to operate and requires a second hardened vent off of the dry portion of the containment. The revised order requires that any necessary changes to the existing vent are to be completed by the second quarter of the 2017 refueling outage at the Monticello plant and a new vent to be added by the second quarter of the 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 external event requirements will cost approximately $50 to $60 million at the Monticello and Prairie Island plants. The majority of these costs are expected to be capital in nature and are included in NSP-Minnesota’s capital expenditure forecasts. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

The NRC continues to review its requirements for mitigating the risks of external events on nuclear plants. In April 2014, the NRC issued a draft of proposed regulatory guidance for risk mitigation of tornado missiles (projectiles impacting the plant). This draft guidance is subject to public comments, further NRC review and possibly public meetings prior to finalization. NSP-Minnesota expects the costs associated with compliance with new NRC regulatory guidance for missile protection to be capital in nature and recoverable from customers. However, at this time NSP-Minnesota is still evaluating the proposed new requirements and has not yet estimated their financial impact.

NSP-Wisconsin

NSP-Wisconsin CapX2020 CPCN — The PSCW issued a CPCN for the Wisconsin portion of the Hampton, Minn. to La Crosse, Wis. project in May 2012. The Wisconsin route is approximately 50 miles of new transmission line with an estimated cost of $211 million. Construction on the Wisconsin terminus of the line, the Briggs Road Substation, began in mid-2013 and construction on the Wisconsin portion of the line is anticipated to begin in mid-2014. The line is expected to go into service in 2015.

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse, Wis. to Madison, Wis. Transmission Line — In October 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a CPCN for a new 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. The proposed line, also known as the Badger Coulee line, would run between 159 and 182 miles. Updated information was provided to the PSCW in April 2014 showing an estimated project cost, including AFUDC, of between $540 and $580 million, depending upon the route ultimately approved by the PSCW. NSP-Wisconsin’s share of the investment is estimated to be between $190 and $207 million. The cost estimates are based on a projected 2018 in-service year. In December 2011, MISO determined the line to be a MVP project, and as such, eligible for cost sharing under MISO’s MVP tariff.

In April 2014, the PSCW determined the application was complete and is expected to issue a decision on the CPCN application in the first half of 2015. If approved, NSP-Wisconsin and ATC anticipate beginning construction on the line in mid-2016, with completion by late-2018.

PSCo

Brush, Colo. to Castle Pines, Colo. 345 KV Transmission Line — In March 2014, PSCo filed with the CPUC for a CPCN to construct a new 345 KV transmission line originating from Pawnee Station, near Brush, Colo. and terminating at the Daniels Park substation, near Castle Pines, Colo. The estimated cost of the project is $178 million. A CPUC decision is expected in early 2015.

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Renewable Energy Standard (RES) Compliance Plan — Colorado law mandates that at least 30 percent of PSCo's energy sales be supplied by renewable energy by 2020 and includes a distributed generation standard. In July 2013, PSCo filed its 2014 RES compliance plan that included the continuation of both the Solar*Rewards and Solar*Rewards Community programs. PSCo also proposed to show in aggregate the system costs that are not avoided by distributed solar generation, which PSCo has defined as a "net metering incentive." In December 2013, parties including the OCC filed answer testimony supporting PSCo's net metering proposal. However, rooftop solar advocates opposed it and also argued for higher solar installation levels and a slower reduction in incentives over time. The CPUC has bifurcated these issues and determined that matters related to the net metering incentive should be heard in a separate proceeding. Hearings for the 2014 RES compliance plan are scheduled for May 2014 with a decision anticipated in the third quarter of 2014. The CPUC is expected to communicate the process to evaluate the net metering incentive in the second quarter of 2014.

Boulder, Colo. Municipalization Exploration — PSCo's franchise agreement with the City of Boulder (Boulder) expired on Dec. 31, 2010. In November 2011, a ballot measure was passed by the citizens of Boulder, which authorized the formation and operation of a municipal light and power utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage.

In August 2013, the Boulder City Council voted to authorize the acquisition of PSCo's transmission and distribution system in and near Boulder. On Jan. 6, 2014, Boulder sent PSCo a Notice of Intent to Acquire (NOIA) for PSCo's transmission, distribution and property assets within an area that includes Boulder and certain areas outside city limits. The NOIA is a legal prerequisite to the filing of an eminent domain proceeding in Colorado courts. However, sending the NOIA does not require Boulder to move forward with a condemnation case. PSCo has informed Boulder that it believes the NOIA was deficient.

On April 16, 2014, the Boulder City Council passed the first reading of an ordinance to amend its code to create a utility. A public hearing and second vote will take place in May 2014. The ordinance is part of the formal process to create an electric utility and would give Boulder the ability to issue bonds should it decide to move forward with acquiring the Boulder business. The ordinance would give Boulder the means to raise money in a timely manner if it decides to move forward with the muncipalization, and can be repealed if Boulder does not.

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

If Boulder commences an eminent domain proceeding, PSCo will seek to obtain full compensation for the business and its associated property taken by Boulder, as well as for all damages resulting to PSCo and its system. PSCo would also seek appropriate compensation for stranded costs with the FERC.

SPS

SPP Integrated Market (IM) — SPP has operated a regional energy imbalance market since 2007. SPS has recovered related charges and revenues in its retail and wholesale rates. In 2012 and 2013, the FERC approved proposed revisions to the SPP tariff to allow SPP to operate a day ahead/real time energy and ancillary services market similar to the regional market operated by MISO. The SPP IM began operations on March 1, 2014. SPS submitted filings to the FERC to modify its wholesale power sales contracts to allow recovery of SPP IM charges and revenues through the SPP wholesale FCA. SPS also requested approval to make sales to the SPP IM at market-based rates, which the FERC approved in February 2014. The FERC approved the FCA tariff filings in April 2014, which were made effective retroactive to March 1, 2014. SPS has also filed changes to its QF tariffs in Texas and New Mexico to allow retail FCA treatment of SPP IM charges and revenues.

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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 (NERC) 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, 2013. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In 2011, 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 regional transmission planning and cost allocation for all FERC-jurisdictional utilities within a region. In addition, Order 1000 required that regions coordinate to develop interregional plans for transmission planning and cost allocation. A key provision of Order 1000 is a requirement that FERC-jurisdictional wholesale transmission tariffs exclude provisions that would grant the incumbent transmission owner a federal Right of First Refusal (ROFR) to build certain types of transmission projects in its service area. Various parties 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. The date for a Court decision in the appeal is uncertain.

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

The FERC has ruled on the initial regional compliance filings for MISO, SPP and PSCo, directing further compliance changes to fully address the requirements of Order 1000. The compliance filings are pending action by the FERC. Initial filings to address interregional planning and cost allocation requirements with other regions were made by PSCo, MISO and SPP in 2013. The filings are pending action by the FERC.

Transmission-only subsidiaries (TransCo)
Xcel Energy has formed a TransCo that could bid for projects subject to a competitive bidding process in MISO. The MISO Board of Directors accepted a membership application for the TransCo on April 24, 2014. Xcel Energy anticipates forming a TransCo that could bid for projects subject to a competitive bidding process in SPP.

NSP System
In 2012, Minnesota enacted legislation that preserves ROFR rights for Minnesota utilities at the state level. This legislation is similar to legislation previously passed in North Dakota and South Dakota. Wisconsin has not developed such legislation. The FERC's initial order on MISO's compliance filing 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. Xcel Energy has requested rehearing of this issue. The rehearing request is pending the FERC's action. The FERC has accepted changes to MISO's transmission cost allocation procedures that will protect the ROFR for projects needed for system reliability. MISO has proposed that the Order 1000 compliance tariffs be effective in

2015.

PSCo

Colorado does not have legislation protecting ROFR rights for incumbent utilities. PSCo submitted its FERC compliance filing proposing that PSCo would join the WestConnect region, a consortium of utilities in the Western Interconnection. In March 2013, the FERC issued its initial order on PSCo’s compliance filing and required a number of changes. In April 2013, PSCo and other WestConnect members requested rehearing on various aspects of the March 2013 order. While requests for rehearing of the March 2013 order are pending, PSCo and other WestConnect jurisdictional utilities made their compliance filings in September 2013 to address directives in the March 2013 order. The FERC is expected to rule in 2014 on the compliance filing and the requests for rehearing that were filed. The WestConnect members filed the interregional compliance filing in May 2013 and action on that filing is pending. The WestConnect members proposed that the regional and inter-regional compliance tariffs be effective prospectively after the final FERC orders, and not earlier than Jan. 1, 2015.

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SPS
The FERC issued its initial order on SPP's Order 1000 regional compliance filing in July 2013. The FERC identified several areas that will require a further compliance filing by SPP to address regional compliance issues. Among other things, the FERC rejected SPP's proposal to retain a ROFR for new transmission projects with operational voltages between 100 KV and 300 KV. Requests for rehearing of the FERC's July 2013 order were filed in August 2013 and are pending the FERC's action. The further SPP regional compliance filing was filed in November 2013. The SPP regional compliance tariffs went into effect March 1, 2014, subject to the outcome of the additional FERC proceedings. The SPP interregional compliance filing was submitted in July 2013 and is pending the FERC's action. With respect to ROFR rights of incumbent utilities, Xcel Energy believes that Texas statutes protect the right of incumbent utilities operating outside of ERCOT 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.

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 expected to serve multiple purposes, such as improved reliability, reduced congestion, transmission for renewable energy, and load serving. Certain parties appealed the FERC MVP tariff orders to the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit). In June 2013, the Seventh Circuit upheld the FERC MVP tariff orders allocating MVP project costs regionally, but remanded the FERC decision to not apply the regional charge to transmission service transactions crossing into the PJM RTO. U.S. Supreme Court review of the Seventh Circuit decision was requested; in March 2014, the U.S. Supreme Court denied the appeal. Appeals of the regional allocation issue have thus been exhausted. The FERC has not yet taken action on the remand of the PJM allocation issue. 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.

NERC Critical Infrastructure Protection (CIP) Requirements — The FERC has approved version 5 of NERC's CIP standards. Requirements must be applied to high and medium impact assets by April 1, 2016 and to low impact assets by April 1, 2017. Xcel Energy is currently in the process of evaluating the new requirements and identifying initiatives needed to meet the compliance deadlines. Compliance is anticipated to require activities across the organization, including Business Systems, Transmission, Energy Supply and Security Services.

On March 7, 2014, FERC issued an order directing NERC to develop a new critical infrastructure protection standard related to physical security. The order directs NERC to file this standard for approval with FERC within 90 days. NERC has prepared a draft of the proposed standard for industry review and comment. The NERC Board of Trustees will consider industry input and votes on the standards and submit a final standard to FERC no later than June 5, 2014. Xcel Energy is participating in the standard development process and will submit its comments on the proposal to NERC. Xcel Energy is also in the process of evaluating the potential impact on the company as the standard is being developed.

SPP and MISO Complaints Regarding RTO Joint Operating Agreement (JOA) — SPP and MISO have a longstanding dispute regarding the interpretation of their JOA, which is intended to coordinate RTO operations along the MISO/SPP system boundary. SPP and MISO disagree over MISO's authority to transmit power over SPP transmission facilities between the traditional MISO region in the Midwest and the Entergy system. Several cases have been filed with the FERC by MISO and SPP. In March 2014, FERC issued an order setting all of the cases for settlement judge proceedings, or hearings if settlement fails. The Xcel Energy utilities have intervened in the various dockets, arguing that non-firm use by MISO should not be subject to SPP transmission charges. If SPP is successful in charging MISO for use of the SPP system, the NSP System would experience higher costs from MISO, which could be material, but SPS would collect revenues from SPP. The outcome of the JOA disputes, and the potential impact on Xcel Energy, are uncertain at this time. The settlement judge process began in April 2014.

Environmental, Legal and Other Matters

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

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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, 2013, 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 March 31, 2014, 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, 2013.

Derivatives, Risk Management and Market Risk

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

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

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

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

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

At March 31, 2014, 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	$8,952	$13,035	$1,981	$420	$24,388
NSP-Minnesota	2	544	—	—	507	1,051
PSCo	1	81	—	—	—	81
		$9,577	$13,035	$1,981	$927	$25,520

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	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	$8	$—	$—	$—	$8

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:

	Three Months Ended March 31	
(Thousands of Dollars)	2014	2013
Fair value of commodity trading net contract assets outstanding at Jan. 1	$30,514	$28,314
Contracts realized or settled during the period	(6,585)	(1,226)
Commodity trading contract additions and changes during period	1,599	1,930
Fair value of commodity trading net contract assets outstanding at March 31	$25,528	$29,018

At March 31, 2014, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income by approximately $0.1 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.1 million. At March 31, 2013, a 10 percent increase or decrease in market prices for commodity trading contracts would have an immaterial impact on pretax income.

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

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

(Millions of Dollars)	Three Months Ended March 31	VaR Limit	Average	High	Low
2014	$0.80	$3.00	$0.77	$1.69	$0.06
2013	0.45	3.00	0.54	1.64	0.23

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 March 31, 2014 and 2013, a 100-basis-point change in the benchmark rate on Xcel Energy’s variable rate debt would impact pretax interest expense annually by approximately $10.2 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.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At March 31, 2014, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. 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. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates do not have an impact on earnings.

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 March 31, 2014, a 10 percent increase in commodity prices would have resulted in a increase in credit exposure of $26.4 million, while a decrease in prices of 10 percent would have resulted in an decrease in credit exposure of $9.6 million. At March 31, 2013, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $4.1 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $13.2 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 March 31, 2014. 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 March 31, 2014.

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 1.7 percent and 28.0 percent of total assets and liabilities, respectively, measured at fair value at March 31, 2014.

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 $27.6 million and $5.3 million of estimated fair values, respectively, for FTRs held at March 31, 2014.

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 included $1.9 million of estimated fair values, and no liabilities, for forwards held at March 31, 2014. There were no Level 3 options held at March 31, 2014.

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 $136.8 million in the nuclear decommissioning fund at March 31, 2014 (approximately 7.9 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

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Liquidity and Capital Resources

Cash Flows

	Three Months Ended March 31	
(Millions of Dollars)	2014	2013
Cash provided by operating activities	$593	$642

Net cash provided by operating activities decreased $49 million for the three months ended March 31, 2014, compared with the three months ended March 31, 2013. The decrease was primarily due to changes in working capital related to the timing of payments and receipts, lower inventory (primarily due to natural gas), as well as net changes in regulatory assets and liabilities. These decreases were partially offset by higher net income and lower pension contributions.

	Three Months Ended March 31	
(Millions of Dollars)	2014	2013
Cash used in investing activities	$(801)	$(713)

Net cash used in investing activities increased $88 million for the three months ended March 31, 2014, compared with the three months ended March 31, 2013. The increase was the result of higher capital expenditures related to transmission and CACJA projects.

	Three Months Ended March 31	
(Millions of Dollars)	2014	2013
Cash provided by financing activities	$233	$102

Net cash provided by financing activities increased $131 million for the three months ended March 31, 2014, compared with the three months ended March 31, 2013. The increase was primarily due to proceeds from short term debt and lower repayments of short-term and long-term debt, partially offset by lower proceeds from long-term debt and issuances of common stock.

Capital Requirements

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

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

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

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

SPP FTR Margining Requirements — The SPP conducted its initial FTR auction associated with implementation of the SPP IM in 2013. The full process for transmission owners involves the receipt of Auction Revenue Rights (ARRs), and if elected by the transmission owner, conversion of those ARRs to firm FTRs. At March 31, 2014, SPS had a $21 million letter of credit posted as collateral for its SPP FTRs.

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

- In January 2014, contributions of $130.0 million were made across three of Xcel Energy's pension plans;
- In 2013, contributions of $192.4 million were made across four of Xcel Energy's pension plans; and
- For future years, we anticipate contributions will be made as necessary.

Capital Sources

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

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At March 31, 2014, approximately $8.1 million of cash was held in these accounts.

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

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

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2014		Twelve Months Ended Dec. 31, 2013	
Borrowing limit	$2,450		$2,450	
Amount outstanding at period end	765		759	
Average amount outstanding	925		481	
Maximum amount outstanding	1,200		1,160	
Weighted average interest rate, computed on a daily basis	0.31	%	0.31	%
Weighted average interest rate at period end	0.33		0.25	

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.45 billion and each credit facility terminates in July 2017.

NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of April 29, 2014, 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	$448.0	$352.0	$0.5	$352.5
PSCo	700.0	83.5	616.5	0.3	616.8
NSP-Minnesota	500.0	285.9	214.1	0.9	215.0
SPS	300.0	212.0	88.0	0.4	88.4
NSP-Wisconsin	150.0	83.0	67.0	1.0	68.0
Total	$2,450.0	$1,112.4	$1,337.6	$3.1	$1,340.7

(a) These credit facilities expire in July 2017.

(b) Includes outstanding commercial paper and letters of credit.

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During the second quarter of 2014, Xcel Energy Inc. and its utility subsidiaries anticipate extending their existing revolving credit agreements.

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 capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

In March 2014, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044.

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

- NSP-Minnesota may issue approximately $300 million of first mortgage bonds;
- SPS may issue approximately $150 million of first mortgage bonds; and
- NSP-Wisconsin may issue approximately $100 million of first mortgage bonds.

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. During the three months ended March 31, 2014, Xcel Energy Inc. entered into sales transactions for 2.6 million shares of common stock with net proceeds of approximately $78 million, which includes transactions initiated but not settled as of March 31, 2014.

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

Credit Ratings — Access to the capital market at reasonable terms is dependent in part on credit ratings. On Jan. 31, 2014, Moody’s upgraded the credit ratings of Xcel Energy and its subsidiaries by one notch. The outlook is stable.

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 2014 ongoing earnings guidance is $1.90 to $2.05 per share. Key assumptions related to 2014 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to increase by up to approximately 1.0 percent.
-

- Weather-normalized retail firm natural gas sales are projected to range from a decline of approximately 1.0 percent to an increase of approximately 1.0 percent.
- Capital rider revenue is projected to increase by $50 million to $60 million over 2013 levels.
- O&M expenses are projected to increase approximately 2 percent to 3 percent over 2013 levels.
- Depreciation expense is projected to increase $40 million to $50 million over 2013 levels, reflecting the proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota's moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $81 million in 2014.
- Property taxes are projected to increase approximately $50 million to $60 million over 2013 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $0 to $10 million from 2013 levels.

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- AFUDC — equity is projected to increase approximately $5 million to $10 million over 2013 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 507 million shares.

Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on a normalized 2013 EPS of $1.90 per share, which represented the mid-point of our 2013 earnings guidance range;
- Deliver annual dividend increases of 4 percent to 6 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is discussed above in Management's Discussion and Analysis — Financial Review under Item 2.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis — Derivatives, Risk Management and Market Risk 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 March 31, 2014, 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.

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Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

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.

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, 2013, 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 March 31, 2014:

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
Jan. 1, 2014 — Jan. 31, 2014 [(a)]	18,874	$28.11	—	—
Feb. 1, 2014 — Feb. 28, 2014	—	—	—	—
March 1, 2014 — March 31, 2014	—	—	—	—
Total	18,874		—	—

(a) Xcel Energy Inc. or one of its agents periodically purchases common shares in order to satisfy obligations under the Stock Equivalent Plan for Non-Employee Directors.

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

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Item 6 — EXHIBITS

* Indicates incorporation by reference

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 dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30 percent First Mortgage Bonds, Series No. 27 due 2044 (Exhibit 4.01 to PSCo's Form 8-K dated March 10, 2014 (file no. 001-03280)).
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 March 31, 2014 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.
May 2, 2014	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)