XCEL ENERGY INC
Form 10-Q
May 01, 2015

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, 2015
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 ¨	Smaller reporting company ¨
(Do not check if 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 27, 2015
Common Stock, $2.50 par value	506,914,489 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. The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin, which is operated on an integrated basis and is managed by NSP-Minnesota, is referred to collectively as the NSP System. 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	
	2015	2014
Operating revenues		
Electric	$2,224,863	$2,301,710
Natural gas	715,996	879,688
Other	21,360	21,206
Total operating revenues	2,962,219	3,202,604
Operating expenses		
Electric fuel and purchased power	950,132	1,067,321
Cost of natural gas sold and transported	472,371	623,828
Cost of sales — other	10,049	9,129
Operating and maintenance expenses	585,830	560,143
Conservation and demand side management program expenses	53,805	77,546
Depreciation and amortization	273,098	245,943
Taxes (other than income taxes)	136,626	124,702
Loss on Monticello life cycle management/extended power uprate project	129,463	—
Total operating expenses	2,611,374	2,708,612
Operating income	350,845	493,992
Other income, net	3,161	3,201
Equity earnings of unconsolidated subsidiaries	7,776	7,438
Allowance for funds used during construction — equity	12,660	21,907
Interest charges and financing costs		
Interest charges — includes other financing costs of $5,698 and $5,792, respectively	144,940	139,094
Allowance for funds used during construction — debt	(6,144)	(9,548)
Total interest charges and financing costs	138,796	129,546
Income before income taxes	235,646	396,992
Income taxes	83,580	135,771
Net income	$152,066	$261,221
Weighted average common shares outstanding:		
Basic	506,983	499,523
Diluted	507,393	499,746

Earnings per average common share:		
Basic	$0.30	$0.52
Diluted	0.30	0.52
Cash dividends declared per common share	$0.32	$0.30

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	
	2015	2014
Net income	$ 152,066	$ 261,221
Other comprehensive income		
Pension and retiree medical benefits:		
Amortization of losses included in net periodic benefit cost, net of tax of $569 and $550, respectively	876	864
Derivative instruments:		
Net fair value decrease, net of tax of $(7) and $(5), respectively	(11)	(7)
Reclassification of losses to net income, net of tax of $382 and $358, respectively	585	560
	574	553
Marketable securities:		
Net fair value increase, net of tax of $0 and $24, respectively	1	38
Other comprehensive income	1,451	1,455
Comprehensive income	$ 153,517	$ 262,676

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

	Three Months Ended March 31	
	2015	2014
Operating activities		
Net income	$152,066	$261,221
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	277,388	250,343
Conservation and demand side management program amortization	1,451	1,555
Nuclear fuel amortization	28,465	28,862
Deferred income taxes	82,773	150,464
Amortization of investment tax credits	(1,384)	(1,443)
Allowance for equity funds used during construction	(12,660)	(21,907)
Equity earnings of unconsolidated subsidiaries	(7,776)	(7,438)
Dividends from unconsolidated subsidiaries	9,876	8,850
Share-based compensation expense	10,225	5,370
Loss on Monticello life cycle management/extended power uprate project	129,463	—
Net realized and unrealized hedging and derivative transactions	12,778	7,384
Changes in operating assets and liabilities:		
Accounts receivable	(291)	(140,962)
Accrued unbilled revenues	183,974	111,417
Inventories	92,010	140,301
Other current assets	56,685	(66,320)
Accounts payable	(99,029)	(37,730)
Net regulatory assets and liabilities	146,097	(253)
Other current liabilities	34,642	1,008
Pension and other employee benefit obligations	(85,469)	(125,780)
Change in other noncurrent assets	(5)	48,054
Change in other noncurrent liabilities	(25,885)	(20,347)
Net cash provided by operating activities	985,394	592,649
Investing activities		
Utility capital/construction expenditures	(770,609)	(822,628)
Proceeds from insurance recoveries	24,241	4,260
Allowance for equity funds used during construction	12,660	21,907
Purchases of investments in external decommissioning fund	(387,826)	(229,548)
Proceeds from the sale of investments in external decommissioning fund	386,111	227,901
Investment in WYCO Development LLC	(321)	(1,161)
Other, net	(2,645)	(1,501)
Net cash used in investing activities	(738,389)	(800,770)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(50,500)	6,000
Proceeds from issuance of long-term debt	—	295,999
Repayments of long-term debt	(455)	(224)
Proceeds from issuance of common stock	1,411	63,548
Dividends paid	(144,025)	(132,033)

Net cash (used in) provided by financing activities	(193,569)	233,290
Net change in cash and cash equivalents	53,436	25,169
Cash and cash equivalents at beginning of period	79,608	107,144
Cash and cash equivalents at end of period	$133,044	$132,313
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(161,717)	$(152,522)
Cash received (paid) for income taxes, net	62,697	(164)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$239,905	$290,058
Issuance of common stock for reinvested dividends and 401(k) plans	14,433	14,525

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

	March 31, 2015	Dec. 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$133,044	$79,608
Accounts receivable, net	826,797	826,506
Accrued unbilled revenues	544,518	728,492
Inventories	505,213	597,183
Regulatory assets	351,780	444,058
Derivative instruments	38,905	85,723
Deferred income taxes	383,463	246,210
Prepaid taxes	118,291	185,488
Prepayments and other	155,435	171,112
Total current assets	3,057,446	3,364,380
Property, plant and equipment, net	28,966,911	28,756,916
Other assets		
Nuclear decommissioning fund and other investments	1,867,425	1,832,640
Regulatory assets	2,760,522	2,774,216
Derivative instruments	51,739	53,775
Other	174,608	175,957
Total other assets	4,854,294	4,836,588
Total assets	$36,878,651	$36,957,884
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$257,399	$257,726
Short-term debt	969,000	1,019,500
Accounts payable	898,003	1,173,006
Regulatory liabilities	393,054	410,729
Taxes accrued	480,311	396,615
Accrued interest	131,579	158,536
Dividends payable	162,130	151,720
Derivative instruments	19,615	21,632
Other	463,437	475,119
Total current liabilities	3,774,528	4,064,583
Deferred credits and other liabilities		
Deferred income taxes	6,085,780	5,852,988
Deferred investment tax credits	72,312	73,696
Regulatory liabilities	1,185,477	1,163,429
Asset retirement obligations	2,476,049	2,446,631
Derivative instruments	178,957	183,936

Customer advances	253,895	256,945
Pension and employee benefit obligations	850,826	936,907
Other	286,487	264,653
Total deferred credits and other liabilities	11,389,783	11,179,185
Commitments and contingencies		
Capitalization		
Long-term debt	11,499,470	11,499,634
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 506,663,770 and 505,733,267 shares outstanding at March 31, 2015 and Dec. 31, 2014, respectively	1,266,659	1,264,333
Additional paid in capital	5,844,995	5,837,330
Retained earnings	3,209,904	3,220,958
Accumulated other comprehensive loss	(106,688)	(108,139)
Total common stockholders' equity	10,214,870	10,214,482
Total liabilities and equity	$36,878,651	$36,957,884

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended March 31, 2015 and 2014						
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
Balance at Dec. 31, 2014	505,733	$1,264,333	$5,837,330	$3,220,958	$ (108,139)	$10,214,482
Net income				152,066		152,066
Other comprehensive income					1,451	1,451
Dividends declared on common stock				(163,120)		(163,120)
Issuances of common stock	931	2,326	893			3,219
Share-based compensation			6,772			6,772
Balance at March 31, 2015	506,664	$1,266,659	$5,844,995	$3,209,904	$ (106,688)	$10,214,870

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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, 2015 and Dec. 31, 2014; 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, 2015 and 2014; and its cash flows for the three months ended March 31, 2015 and 2014. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2015 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, 2014 balance sheet information has been derived from the audited 2014 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2014. 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, 2014, filed with the SEC on Feb. 20, 2015. 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, 2014, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Revenue Recognition — In May 2014, the Financial Accounting Standards Board (FASB) issued Revenue from Contracts with Customers, Topic 606 (Accounting Standards Update (ASU) No. 2014-09), which provides a framework for the recognition of revenue, with the objective that recognized revenues properly reflect amounts an entity is entitled to receive in exchange for goods and services. This guidance, which includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers, is effective for interim and annual reporting periods beginning after Dec. 15, 2016. In April 2015, the FASB tentatively decided to defer the effective date by one year, making the guidance effective for interim and annual reporting periods beginning after Dec. 15, 2017. This tentative decision will be exposed for public input in an upcoming proposed ASU with a 30-day comment period. Xcel Energy is currently evaluating the impact of adopting ASU 2014-09 on its consolidated financial statements.

Consolidation — In February 2015, the FASB issued Amendments to the Consolidation Analysis, Topic 810 (ASU No. 2015-02), which reduces the number of consolidation models and amends certain consolidation principles related to variable interest entities. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15. 2015, and early adoption is permitted. Xcel Energy is currently evaluating the impact of adopting ASU 2015-02 on its consolidated financial statements.

Presentation of Debt Issuance Costs — In April 2015, the FASB issued Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30 (ASU No. 2015-03), which amends existing guidance to require the presentation of debt issuance costs on the balance sheet as a deduction from the carrying amount of the related debt, instead of an asset. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Other than the prescribed reclassification of assets to an offset of debt on the consolidated balance sheets, Xcel Energy does not expect the implementation of ASU 2015-03 to have a material impact on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	March 31, 2015	Dec. 31, 2014
Accounts receivable, net		
Accounts receivable	$882,625	$884,225
Less allowance for bad debts	(55,828)	(57,719)
	$826,797	$826,506

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(Thousands of Dollars)	March 31, 2015	Dec. 31, 2014
Inventories		
Materials and supplies	$254,385	$244,099
Fuel	174,149	183,249
Natural gas	76,679	169,835
	$505,213	$597,183

(Thousands of Dollars)	March 31, 2015	Dec. 31, 2014
Property, plant and equipment, net		
Electric plant	$33,541,957	$33,203,139
Natural gas plant	4,692,601	4,643,452
Common and other property	1,619,160	1,611,486
Plant to be retired [(a)]	64,130	71,534
Construction work in progress	2,010,792	2,005,531
Total property, plant and equipment	41,928,640	41,535,142
Less accumulated depreciation	(13,373,008)	(13,168,418)
Nuclear fuel	2,396,974	2,347,422
Less accumulated amortization	(1,985,695)	(1,957,230)
	$28,966,911	$28,756,916

(a) 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, 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, 2014 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2009 federal income tax return expires in March 2016. 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, 2015, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $12 million of income tax expense for the 2009 through 2011 claims, the recently filed 2013 claim, and the anticipated claim for 2014. As of March 31, 2015, the IRS has begun the Appeals process; however, 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, 2015, 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	2010

As of March 31, 2015, 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, 2015	Dec. 31, 2014
Unrecognized tax benefit — Permanent tax positions	$16.3	$16.2
Unrecognized tax benefit — Temporary tax positions	53.7	50.3
Total unrecognized tax benefit	$70.0	$66.5

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

(Millions of Dollars)	March 31, 2015	Dec. 31, 2014
NOL and tax credit carryforwards	$(31.9)	$(28.5)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS appeals process progresses and state audits resume. As the IRS appeals process moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $10 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, 2015 and Dec. 31, 2014 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2015 or Dec. 31, 2014.

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, 2014 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 was 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 initially reflected a requested 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 included a proposed rate moderation plan for 2014 and 2015. In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund.

In 2014, NSP-Minnesota revised its requested rate increase to $115.3 million for 2014 and to $106.0 million for 2015, for a total combined unadjusted increase of $221.3 million.

In December 2014, the administrative law judge (ALJ) issued her recommendations in the NSP-Minnesota electric rate case. NSP-Minnesota estimated that her recommendations would have resulted in a rate increase of $69.1 million in 2014 and an incremental rate increase of $122.4 million in 2015. In addition, she recommended an ROE of 9.77 percent and an equity ratio of 52.5 percent.

On March 26, 2015, the MPUC voted to approve a 2014 rate increase and a 2015 step increase. NSP-Minnesota estimates the total rate increase to be approximately $168 million, or 6.1 percent, based on a 9.72 percent ROE and 52.50 percent equity ratio. The MPUC largely approved the ALJ’s recommendations and the excess depreciation reserve utilization of 50 percent, 30 percent and 20 percent in 2014, 2015, and 2016, respectively. The MPUC did not adopt NSP-Minnesota’s 2016 rate case avoidance proposal. NSP-Minnesota is initiating the preparation of its 2016 rate case. NSP-Minnesota will evaluate how best to proceed including whether proposed legislation could provide alternative approaches, whether rate moderation is available and whether to propose a single or multi-year request.

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The following table reconciles NSP-Minnesota’s original request to the MPUC's March 26, 2015 verbal decision, including the estimated ongoing impact of their March 6, 2015 verbal decision in the Monticello Prudence Review on the Minnesota retail electric jurisdiction:

2014 Rate Request (Millions of Dollars)	NSP-Minnesota	ALJ	MPUC Decision
NSP-Minnesota’s filed rate request	$ 192.7	$ 192.7	$ 192.7
Sales forecast (with true-up to 12 months of actual weather-normalized sales)	(38.5)	(38.5)	(38.5)
ROE	—	(28.4)	(31.9)
Monticello extended power uprate (EPU) cost recovery	(12.2)	(31.3)	(37.6)
Property taxes (with true-up to actual 2014 accruals)	(13.2)	(13.2)	(13.2)
Prairie Island EPU cost recovery	(5.1)	(5.1)	(5.1)
Health care, pension and other benefits	(1.9)	(1.9)	(3.0)
Other, net	(6.5)	(5.2)	(5.3)
Total 2014	$ 115.3	$ 69.1	$ 58.1
2015 Rate Request (Millions of Dollars)	NSP-Minnesota	ALJ	MPUC Decision
NSP-Minnesota’s filed rate request	$ 98.5	$ 98.5	$ 98.5
Monticello EPU cost recovery	11.7	29.1	35.4
Depreciation / Retirements	—	—	(0.5)
Property taxes	(3.3)	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)	(11.1)
U.S. Department of Energy (DOE) settlement proceeds	10.1	10.1	10.1
Emission chemicals	(1.6)	(1.6)	(1.6)
Other, net	1.7	0.7	0.2
Total 2015 step increase - prior to Monticello EPU cost disallowance	$ 106.0	$ 122.4	$ 127.7
Total for 2014 and 2015 step increase - prior to Monticello EPU cost disallowance	$ 221.3	$ 191.5	$ 185.8
Monticello EPU cost disallowance - ongoing impact	—	—	(18.2)
Total for 2014 and 2015 step increase - including Monticello EPU cost disallowance	$ 221.3	$ 191.5	$ 167.6

The MPUC also approved a full revenue decoupling three-year pilot with a 3 percent cap on base revenue for the residential and small commercial and industrial classes, based on actual sales, effective Jan. 1, 2016. The decoupling mechanism would eliminate the impact of weather variability on electric sales for these classes. NSP-Minnesota can seek to recover amounts over the cap provided it can show that its demand-side management and/or other initiatives were a substantial contributing factor to the declining energy consumption and that other non-conservation factors were not the primary factors for the under-recovery.

The MPUC made no determination on NSP-Minnesota's interim rate refund proposal. There are currently two proposals in the case regarding the potential refund for interim rates for 2014 and 2015. NSP-Minnesota has requested that the MPUC treat the multi-year case as a single period and net the two-year period for any potential refund/surcharge that could occur when final rates are established. The Minnesota Department of Commerce identified an alternative option that views each year of the multi-year case separately, which would result in lower 2015 revenues by approximately $3.5 million per month between Jan. 1, 2015 and the date that final rates are determined. The final order is expected to be issued May 8, 2015. NSP-Minnesota filed the initial parts of a compliance filing calculating the final authorized rates in April 2015 and plans to file the remaining portions during May 2015. The MPUC is expected to rule on interim rates after the comment period for the compliance filing.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello life cycle management (LCM)/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 megawatts (MW). Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes allowance for funds used during construction (AFUDC). In 2008, project expenditures were initially estimated at approximately $320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

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On March 6, 2015, the MPUC voted to allow for full recovery, including a return, on approximately $415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment over the remaining life of the plant. Further, the MPUC determined that only 50 percent of the investment was considered used and useful for 2014. As a result of these determinations and assuming the other state commissions within the NSP System jurisdictions adopt the MPUC's decisions, Xcel Energy recorded an estimated pre-tax loss of $129 million in the first quarter of 2015. The remaining book value of the Monticello project represents the present value of the estimated future cash flows allowed for by the MPUC.

In addition, the decision would reduce the 2015 revenue requirement and pre-tax income for Xcel Energy (assuming other state commissions adopt the MPUC decision) and the Minnesota retail electric jurisdiction as follows:

(Millions of Dollars)	Revenue	Pre-tax Income (a)
Xcel Energy	$25	$16
Minnesota retail electric jurisdiction	18	12

(a) Pre-tax income reflects the net impact of the reductions in revenue and depreciation expense.

Review of the final written order, which is anticipated in the second quarter of 2015, could impact NSP-Minnesota's calculations. NSP-Minnesota will have the ability to file for reconsideration.

NSP-Minnesota – 2015 Transmission Cost Recovery (TCR) Rate Filing — In October 2014, the 2015 NSP-Minnesota TCR filing was filed with the MPUC, requesting recovery of $65.8 million of 2015 transmission investment costs not previously included in electric base rates. An MPUC decision is anticipated in the second quarter of 2015, with implementation of new rates soon after approval.

Pending Regulatory Proceedings — South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota – South Dakota 2015 Electric Rate Case — In June 2014, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. The request is based on a 2013 historic test year (HTY) adjusted for certain known and measurable changes for 2014 and 2015, a requested ROE of 10.25 percent, an average rate base of $433.2 million and an equity ratio of 53.86 percent. This request reflects NSP-Minnesota's proposal to move recovery of approximately $9.0 million for certain TCR rider and Infrastructure rider projects to base rates.

Interim rates of $15.6 million, subject to refund, went into effect in January 2015. At this time, the parties are in settlement discussion and further procedure scheduling may be established, as necessary. Final rates are anticipated to be effective mid-2015.

PSCo

Pending and Recently Concluded Regulatory Proceedings — Colorado Public Utilities Commission (CPUC)

PSCo – Colorado 2014 Electric Rate Case — In 2014, PSCo filed an electric rate case with the CPUC requesting an increase in annual revenue of approximately $136.0 million, or 4.83 percent. The requested 2015 rate increase reflected approximately $100.9 million (subsequently updated to $98.7 million) for recovery of costs associated with the Clean Air Clean Jobs Act (CACJA) project. The case also requested the initiation of a CACJA rider for 2016 and 2017, which was anticipated to increase revenue recovery by approximately $34.2 million in 2016 and then decline to approximately $29.9 million in 2017.

In December 2014, PSCo filed rebuttal testimony, revising its requested rate increase to $107.2 million, or 3.79 percent, reflecting an ROE of 10.25 percent and updated information for both the sales and property tax forecasts. PSCo also proposed to recover all costs associated with the CACJA project through the rider beginning in 2015.

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In February 2015, the CPUC approved a settlement agreement with rates effective on Feb. 13, 2015. This agreement results in an overall 2015 revenue increase of approximately $53.3 million, or 1.87 percent. Key terms of the agreement include the following:

- The settlement is based on a 2013 HTY, an ROE of 9.83 percent and an equity ratio of 56 percent;
- The implementation of a forward-looking CACJA rider of approximately $97.0 million for 2015 with step increases of $17.7 million and $14.5 million for 2016 and 2017, respectively, effective Jan. 1, 2015;
- A forward-looking transmission cost adjustment (TCA) rider of approximately $15.6 million, effective Feb. 13, 2015;
- Establishment of tracking mechanisms for pension expense and property taxes; and
- An earnings test for 2015 through 2017, under which PSCo and customers would share in any earnings on a 50/50 basis if the ROE recognized falls between 9.84 percent and 10.48 percent.

The components of the overall 2015 revenue increase are as follows:

(Millions of Dollars)	Approved Settlement
Total base rate decrease	$(39.4)
CACJA rider mechanism	97.0
TCA rider mechanism	15.6
Transfer from TCA rider to base rates	(19.9)
Total revenue increase	$53.3

In addition to the revenue increase of $53.3 million, including the impact of the riders, PSCo estimates that it will defer approximately $3.1 million of additional expenses in 2015 as a result of the settlement.

PSCo – Colorado 2015 Multi-Year Gas Rate Case — On March 3, 2015, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas base rates by $40.5 million, or 3.5 percent, in 2015, with subsequent step increases of $7.6 million, or 0.7 percent, in 2016 and $18.1 million, or 1.5 percent, in 2017.

The request is based on a historic test year ended June 30, 2014 adjusted for known and measurable expenses and capital additions for each of the subsequent periods in the multi-year plan and an equity ratio of 56 percent. The rate case requests a ROE of 10.1 percent for 2015 and 2016 and 10.3 percent for 2017, and a rate base of $1.26 billion for 2015, $1.31 billion for 2016 and $1.36 billion for 2017.

PSCo is also proposing a stay-out provision, in which PSCo would not request implementation of new rates prior to January 2018, and to implement an earnings test for 2016 through 2017. Under the earnings test, PSCo and customers would share in any earnings on a 50/50 basis if the ROE recognized falls between 10.2 percent and 10.6 percent in 2016, and between 10.4 percent and 10.8 percent in 2017.

In addition, PSCo requested an extension of its pipeline system integrity adjustment (PSIA) rider through 2020 to recover costs associated with its pipeline integrity efforts, including accelerated system renewal projects. If the PSIA rider is not extended by Dec. 31, 2015, such costs would be included in base rates. The request to extend and modify the PSIA rider has an expected negative revenue impact of approximately $0.1 million in 2015 and would provide incremental revenue of $21.7 million for 2016 and $21.2 million for 2017. If PSCo's proposal is accepted, PSIA revenue is projected to be $67.0 million in 2015, $88.7 million in 2016, and $109.9 million in 2017.

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The following table summarizes the request:

(Millions of Dollars)	2015	2016 Step	2017 Step
Net plant and plant related expenses	$24.4	$12.4	$12.0
Operating and maintenance expenses	23.9	(5.2)	0.6
Property and payroll taxes	4.7	2.6	4.0
ROE	4.5	—	2.4
Capital structure	(1.0)	—	0.1
Sales forecast	(17.1)	(2.2)	(1.0)
Other, net	1.1	—	—
Total base rate increase	40.5	7.6	18.1
Incremental PSIA rider revenues	(0.1)	21.7	21.2
Total revenue impact	$40.4	$29.3	$39.3

In March 2015, the CPUC referred the proceeding to an ALJ. A CPUC decision, as well as implementation of final rates, are anticipated in the fourth quarter of 2015.

PSCo – Annual Electric Earnings Test — As part of an annual earnings test, PSCo must share with customers a portion of any annual earnings that exceed PSCo’s authorized ROE threshold of 10 percent for 2012 through 2014. On April 30, 2015, PSCo filed a tariff for the 2014 earnings test with the CPUC proposing a refund obligation of $66.5 million to electric customers.

In February 2015, in the Colorado 2014 Electric Rate Case, the CPUC approved an annual earnings test, in which PSCo shares with customers earnings that exceed the authorized ROE threshold of 9.83 percent for 2015 through 2017. The current estimate of the 2015 earnings test, based on annual forecasted information, did not result in the recognition of a liability as of March 31, 2015.

Electric, Purchased Gas and Resource Adjustment Clauses

Demand Side Management (DSM) and the Demand Side Management Cost Adjustment (DSMCA) — The CPUC approved higher savings goals and a lower financial incentive mechanism for PSCo’s electric DSM energy efficiency programs starting in 2015. Energy efficiency and DSM costs are recovered through a combination of the DSMCA riders and base rates. DSMCA riders are adjusted biannually to capture program costs, performance incentives, and any over- or under-recoveries are trued-up in the following year. Savings goals were 384 gigawatt hours (GWh) in 2014 and are 400 GWh in 2015 with incentives awarded in the year following plan achievements. PSCo is able to earn $5 million upon reaching its annual savings goal along with an incentive on five percent of net economic benefits up to a maximum annual incentive of $30 million.

In October 2014, PSCo filed its 2015-2016 DSM plan, which proposes a 2015 DSM electric budget of $81.6 million and a gas budget of $13.1 million and a 2016 DSM electric budget of $78.7 million and gas budget of $13.6 million. PSCo has reached an agreement with all parties resolving most of the contested issues in the proceeding. The remaining issues to be litigated primarily concern the avoided costs attributable to DSM measures. A decision by the ALJ is expected in the second quarter of 2015.

SPS

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

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric, non-fuel rate case in Texas seeking an overall increase in annual revenue of approximately $64.8 million, or 6.7 percent. The filing was based on an HTY ended June 2014, adjusted for known and measurable changes, an ROE of 10.25 percent, an electric rate base of approximately $1.6 billion and an equity ratio of 53.97 percent. In March 2015, SPS revised its requested increase to $58.9 million based on updated information.

As part of its request, SPS is seeking a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of $392 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014.

The following table summarizes the net request:

(Millions of Dollars)	Request
Investment for capital expenditures — post-test year adjustments	$23.7
Depreciation expense	13.9
Wholesale load reductions	12.0
Purchased power capacity costs	3.2
Other, net	6.1
Total	$58.9

In April 2015, a revised procedural schedule was established. The next steps are expected to be as follows:

- Intervenor Direct Testimony — May 15, 2015;
- Staff Direct Testimony — May 22, 2015;
- Staff and Intervenor Cross-Rebuttal Testimony — June 8, 2015;
- Rebuttal Testimony — June 10, 2015; and
- Evidentiary Hearing — June 24, 2015.

The parties have agreed the rates will be effective June 11, 2015. A PUCT decision is anticipated in the second half of 2015.

Pending and Recently Concluded Regulatory Proceedings — Federal Energy Regulatory Commission (FERC)

SPS – Wholesale Rate Complaints — In April 2012, Golden Spread Electric Cooperative, Inc. (Golden Spread), a wholesale cooperative customer, filed a rate complaint alleging that the base ROE included in the SPS production formula rate for Golden Spread of 10.25 percent, and the SPS transmission base formula rate ROE of 10.77 percent, are unjust and unreasonable. In July 2013, Golden Spread filed a second complaint, again asking that the base ROE in the SPS production formula rate for Golden Spread and transmission formula rates be reduced to 9.15 and 9.65 percent, respectively. In June 2014, the FERC issued orders consolidating the Golden Spread ROE complaints and setting the complaints for settlement judge or hearing procedures.

The FERC established effective dates for the refunds as April 20, 2012 (first refund period) and July 19, 2013 (second refund period). Settlement judge procedures were unsuccessful and the complaints were set for hearings. In the first quarter of 2015, Golden Spread, SPS and FERC staff filed their initial testimonies recommending the following ROEs:

	Refund Period	Production ROE	Transmission ROE [(a)]
Golden Spread	1	8.78 %	9.28 %
	2	8.51	9.01
SPS	1	10.25	10.39
	2	10.25	11.20
FERC Staff	1	8.97	9.47
	2	8.64	9.14

(a) Includes a Southwest Power Pool, Inc. (SPP) RTO membership adder up to 50 basis points.

Hearings are scheduled for July 2015. An initial ALJ decision is expected to be issued by Nov. 25, 2015, and a final FERC order to be issued no earlier than 2016.

A third rate complaint was filed in October 2014 by Golden Spread, along with certain New Mexico cooperatives and the West Texas Municipal Power Agency, requesting that the ROE in the SPS production formula rates for Golden Spread and the New Mexico cooperatives and SPS transmission formula rate, which includes an SPP RTO membership adder up to 50 basis points, be reduced to 8.61 percent and 9.11 percent, respectively. The complainants requested a refund effective date of Oct. 20, 2014. In January 2015, the FERC issued an order setting the third complaint for hearing procedures and granting the complainants' requested refund effective date. A hearing is scheduled for October 2015, with an ALJ initial decision expected in January 2016, and a final FERC order following later in 2016.

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SPS recorded a current liability representing the current best estimate of a refund obligation associated with potential ROE adjustments as of March 31, 2015, and is reducing transmission and production revenues, net of expense, between $4 million and $6 million annually.

SPS – 2004 FERC Complaint Case Orders — In August 2013, the FERC issued an order related to a 2004 complaint case brought by Golden Spread and Public Service Company of New Mexico (PNM) and an Order on Initial Decision in a subsequent 2006 production rate case filed by SPS.

The original complaint included two key components: 1) PNM's claim regarding inappropriate allocation of fuel costs and 2) a base rate complaint, including the appropriate demand-related cost allocator. The FERC previously determined that the allocation of fuel costs and the demand-related cost allocator utilized by SPS was appropriate.

In the August 2013 Orders, the FERC clarified its previous ruling on the allocation of fuel costs and reaffirmed that the refunds in question should only apply to firm requirements customers and not PNM's contractual load. The FERC also reversed its prior demand-related cost allocator decision. The FERC stated that it had erred in its initial analysis and concluded that the SPS system was a 3 coincident peak (CP) rather than a 12CP system.

In September 2013, SPS filed a request for rehearing of the FERC ruling on the CP allocation and refund decisions. SPS asserted that the FERC applied an improper burden of proof and that precedent did not support retroactive refunds. PNM also requested rehearing of the FERC decision not to reverse its prior ruling. In October 2013, the FERC issued orders further considering the requests for rehearing, which are currently pending. As of Dec. 31, 2014, SPS had accrued $50.4 million related to the August 2013 Orders and an additional $1.8 million of principal and interest was accrued during 2015.

SPS – 2015 Formula Rate Change Filing — In January 2015, SPS filed to revise the production formula rates for six of its wholesale customers, including Golden Spread, effective Feb. 1, 2015. The filing proposes several modifications, including a reduction in wholesale depreciation rates and the use of a 12 CP demand-related cost allocator for all wholesale customers. On March 31, 2015, the FERC accepted this filing, effective July 1, 2015, subject to refund and settlement judge or hearing procedures. The parties are engaged in settlement judge procedures.

Pending Regulatory Proceedings — FERC

Midcontinent Independent System Operator, Inc. (MISO) ROE Complaint/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners (TOs), including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for regional transmission organization (RTO) membership and being an independent transmission company), effective Nov. 12, 2013.

In June 2014, the FERC issued an order in a different ROE proceeding adopting a new ROE methodology for electric utilities. The new ROE methodology requires electric utilities to use a two-step discounted cash flow analysis to estimate cost of equity that incorporates both short-term and long-term growth projections.

In October 2014, the FERC upheld the determination of the long-term growth rate to be used together with a short-term growth rate in its new ROE methodology. The FERC separately set the ROE complaint against the MISO TOs for settlement and hearing procedures. The FERC directed parties to apply the new ROE methodology, but denied the complaints related to equity capital structures and ROE adders. The FERC established a Nov. 12, 2013 refund effective date. The settlement procedures were unsuccessful. FERC action is pending. In January 2015, the

ROE complaint was set for full hearing procedures, with an ALJ initial decision to be issued by November 2015 and a FERC order issued no earlier than 2016.

In November 2014, the MISO TOs filed a request for FERC approval of a 50 basis point RTO membership ROE adder, with collection deferred until resolution of the ROE complaint. In January 2015, the FERC approved the ROE adder, subject to the outcome of the ROE complaint. The total ROE, including the RTO membership adder, may not exceed the top of the discounted cash flow range under the new ROE methodology. In 2015, several intervenors sought rehearing of the commission order.

In February 2015, a separate group of customers filed an additional complaint proposing to reduce the MISO region ROE to 8.67 percent, prior to any 50 basis point RTO adder, with a refund effective date of Feb. 12, 2015. The FERC has to date taken no action on the second complaint.

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NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE as of March 31, 2015. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between $7 million and $9 million annually for the NSP System.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5, 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, 2014, appropriately represent, in all material respects, the current status of commitments and contingent liabilities, 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.

The Xcel Energy utility subsidiaries had approximately 3,698 MW of capacity under long-term PPAs as of March 31, 2015 and Dec. 31, 2014, 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 2033.

Guarantees and Bond 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, 2015 and Dec. 31, 2014, 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, 2015	Dec. 31, 2014
Guarantees issued and outstanding	$13.9	$13.9
Current exposure under these guarantees	0.1	0.2
Bonds with indemnity protection	31.9	31.4

Other Indemnification Agreements

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

Environmental Contingencies

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

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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.

In 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, for future 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. Fieldwork to address the Phase I Project Area at the Ashland site began at the end of 2012 and continues. Demolition activities occurred at the Ashland site in 2013. Soil, including excavation and treatment, as well as containment wall remedies were completed in early 2015. A preliminary design for the groundwater remedy was also submitted to the EPA in April 2014 and those activities are expected to commence in 2015. The current cost estimate for the cleanup of the Phase I Project Area is approximately $57 million, of which approximately $33 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.

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay for or perform the cleanup of the Sediments and what remedy will be implemented at the site to address the Sediments. It is NSP-Wisconsin’s view that 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. In November 2013, NSP-Wisconsin submitted a revised Wet Dredge pilot study work plan proposal to the EPA. In May 2014, NSP-Wisconsin entered into a final administrative order on consent for the Wet Dredge pilot study with the EPA. In early 2015, the EPA granted an extension of time to perform the pilot in 2016 so that NSP-Wisconsin can first construct a breakwater at the site to serve as a wave attenuator.

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 commenced on April 27, 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. A final settlement has been reached between NSP-Wisconsin, along with the EPA, and two of the PRPs, Wisconsin Central Ltd. and Soo Line Railroad Co. (collectively, the “Railroad PRPs”) resolving claims relating to the Railroad PRPs’ share of the costs of cleanup at the Ashland site. NSP-Wisconsin also has entered a second private party settlement agreement with LE Myers Co. Under the agreements, the Railroad PRPs will contribute $10.5 million and LE Myers Co. will contribute $5.4 million to the costs of the cleanup at the Ashland site. The agreement for the Railroad PRPs along with LE Myers Co. was approved by the U.S. District Court for the Western District of Wisconsin in 2015. As discussed below, existing Public Service Commission of Wisconsin (PSCW) policy requires that any payments received from PRPs be used to reduce the amount of the cleanup costs ultimately recovered from customers.

At March 31, 2015 and Dec. 31, 2014, NSP-Wisconsin had recorded a liability of $112.4 million and $107.6 million, respectively, for the Ashland site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $26.0 million and $28.9 million, respectively, was considered a current liability. NSP-Wisconsin’s potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, potential contributions by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

NSP-Wisconsin has deferred the estimated site remediation costs, as a regulatory asset, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. Under the established PSCW policy, 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. Any payments received from insurance carriers or PRPs are recorded as a reduction of the regulatory asset. Once deferred MGP remediation costs are determined by the PSCW to be prudent, utilities are allowed to recover those deferred costs in natural gas rates, typically over a four- to six-year amortization period. The PSCW historically has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation.

The PSCW reviewed the existing MGP cost recovery policy as it applied to the Ashland site in the context of NSP-Wisconsin's 2013 general rate case. In their final decision, dated Dec. 27, 2012, 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 a 2014 rate case decision, the PSCW continued the cost recovery treatment with respect to the 2013 and 2014 cleanup costs for the Phase I Project Area and 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. Cost recovery will continue at the level set in the 2014 rate case though 2015, but will be re-assessed in NSP-Wisconsin’s next natural gas rate case.

Environmental Requirements

Water and Waste

Coal Ash Regulation — Xcel Energy’s operations are subject to federal and state laws that impose requirements for handling, storage, treatment, and disposal of solid waste. On April 17, 2015, the EPA published a final rule regulating the management and disposal of coal combustion byproducts (coal ash) as a nonhazardous waste. Xcel Energy’s costs to manage and dispose of coal ash will not significantly increase under the new rule.

Air

Cross-State Air Pollution Rule (CSAPR) — CSAPR addresses 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 using an emissions trading program. For Xcel Energy, the rule applies in Minnesota, Wisconsin and Texas.

In August 2012, the United States District 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 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 Supreme 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. An opinion is expected late summer 2015. In October 2014, the D.C. Circuit granted the EPA’s request to begin to implement CSAPR by imposing its 2012 compliance obligations starting in January 2015. While the litigation continues, the EPA will administer the CSAPR in 2015.

Multiple changes to the SPS system since 2011 will substantially reduce estimated costs of complying with the CSAPR. These include the addition of 700 MW of wind power, the construction of Jones Units 3 and 4, reduced wholesale load, new PPAs, installation of NOx combustion controls on Tolk Units 1 and 2 and completion of certain transmission projects. As a result, SPS estimates compliance with the CSAPR in 2015 will cost approximately $7 million.

NSP-Minnesota can operate within its CSAPR emission allowance allocations. NSP-Wisconsin can operate within its CSAPR emission allowance allocation for SO_2. NSP-Wisconsin anticipates compliance with the CSAPR for NOx in 2015 through operational changes or allowance purchases. CSAPR compliance in 2015 is not expected to have a material impact on the results of operations, financial position or cash flows.

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Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. 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 its 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. Installation of the emission controls at Hayden Unit 1 is scheduled for 2015 and Hayden Unit 2 is scheduled for 2016 at an estimated combined cost of $82.4 million. PSCo anticipates these costs will be fully recoverable in rates.

In March 2013, WildEarth Guardians petitioned the U.S. Court of Appeals for the 10^{th} Circuit to review the EPA’s decision approving the Colorado SIP. WildEarth Guardians has challenged 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. In September 2014, the EPA filed a request with the Court to remand the case to the EPA for additional explanation of the EPA’s decision approving the BART determination for Comanche Units 1 and 2. In October, 2014, the Court granted the EPA’s request and vacated the current briefing schedule. In its February 2015 status report to the Court the EPA estimated that it would submit a final rule for publication which is expected in 2015.

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 Minnesota Pollution Control Agency (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 were installed first and the scrubber upgrades were completed in December 2014, at a cost of $46.9 million. 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 (Eighth Circuit).

NSP-Minnesota and other regulated parties were denied intervention. In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In October 2014, the Eighth Circuit set a briefing schedule that was completed in February 2015. An argument date has not been set. 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.

SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas developed a SIP (the Texas SIP) that finds the Clean Air Interstate Rule (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. In December 2014, the EPA proposed to approve the BART portion of the Texas SIP, with the exception that the EPA would substitute CSAPR compliance for Texas' reliance on CAIR. The EPA currently plans to issue its final rule in August 2015.

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In May 2014, the EPA issued a request for information under the CAA related to SO_2 control equipment at Tolk Units 1 and 2. In December 2014, the EPA proposed to disapprove the reasonable progress portions of the Texas SIP and instead adopt a Federal Implementation Plan. For SPS, the EPA proposed to require dry scrubbers on both Tolk units to reduce SO_2 emissions to help achieve reasonable progress goals the EPA would establish for Texas and Oklahoma national parks and wilderness areas. As proposed, the dry scrubbers would need to be installed and operating within five years of the EPA's final action, currently expected in August 2015. SPS filed comments in April 2015, opposing the proposal. Whether dry scrubbers are required is dependent on the EPA's final decision. If required, they would cost approximately $600 million, with an annual operating cost of approximately $10.4 million.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a national park. 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 whether there is RAVI-type impairment in these parks and examine which sources may cause or contribute to any RAVI impact that is identified. After studying the national parks and evaluating multiple sources, if the EPA finds that Sherco Units 1 and 2 cause or contribute to RAVI in the national parks, the EPA would then evaluate 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.

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 District Court denied NSP-Minnesota's motion to intervene in July 2013. NSP-Minnesota appealed this decision to the Eighth Circuit, which on July 23, 2014, reversed the District Court and found that NSP-Minnesota has standing and a right to intervene.

In June 2014, the EPA and the plaintiffs lodged a consent decree with the District Court. The public comment period on the draft consent decree has been completed. The EPA has not filed a motion to enter the consent decree with the District Court.

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.

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Employment, Tort and Commercial Litigation

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. On Jan.16, 2015, Exelon Wind filed motions to dismiss or notices of non-suits for its state and federal lawsuits regarding the QF tariff, and for its state and federal lawsuits and regulatory proceedings regarding the LEOs. Later in January, the PUCT and state and federal courts issued orders dismissing the cases. On April 28, 2015, Exelon Wind filed a notice of withdrawal of its complaint regarding the LEOs, which will become effective on May 13, 2015. The only remaining proceeding is pending before the FERC, and involves the QF Tariff.

SPS believes the likelihood of loss in these 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 U.S. Court of Appeals for the Ninth Circuit (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. The City of Seattle filed a petition for review with the Court of Appeals for the Ninth Circuit seeking review of FERC's order on remand.

Notwithstanding its petition for review, 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.

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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 contested the FERC ALJ's initial decision by filing a brief on exceptions to the FERC. This matter is now pending a decision by the FERC.

In addition, on Feb. 17, 2015, the U.S. Court of Appeals of the Ninth Circuit directed parties to the pending FERC proceeding to submit briefs addressing, among other issues, the petition for review filed by the City of Seattle seeking review of FERC's order on remand. Parties are directed to address whether FERC's order properly established the scope for the hearing that concluded in October 2013. Respondent-intervenors, such as PSCo, are required to submit briefs on or before May 8, 2015. Oral argument is scheduled to commence in June 2015.

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, notwithstanding 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 additional cost reimbursement for certain transportation costs incurred since 2007, as well as reimbursement for similar costs in future periods. Fibrominn claims that it is entitled to reimbursement from NSP-Minnesota for past transportation costs of approximately $20 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 in rates. 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 DOE's 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. In December 2014, NSP-Minnesota received a settlement payment of $32.8 million. NSP-Minnesota has received a total of $214.7 million of settlement proceeds as of March 31, 2015. Amounts received from the installments, except for approved reductions such as legal costs, will be subsequently returned to customers through a reduction of future rate increases or 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.

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, 2015	Twelve Months Ended Dec. 31, 2014
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	969	1,020
Average amount outstanding	1,076	841
Maximum amount outstanding	1,360	1,200
Weighted average interest rate, computed on a daily basis	0.46 %	0.33 %
Weighted average interest rate at period end	0.55	0.56

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, 2015 and Dec. 31, 2014, there were $61 million of letters of credit outstanding 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, 2015, 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.	$1,000	$548	$452
PSCo	700	149	551
NSP-Minnesota	500	100	400
SPS	400	153	247
NSP-Wisconsin	150	80	70
Total	$2,750	$1,030	$1,720

[a] These credit facilities expire in October 2019.
[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, 2015 and Dec. 31, 2014.

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.

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

Electric commodity derivatives held by NSP-Minnesota may include transmission congestion instruments purchased from MISO, PJM Interconnection, LLC, Electric Reliability Council of Texas, 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 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 Nuclear Regulatory Commission (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 (PI) 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 $332.2 million and $312.1 million at March 31, 2015 and Dec. 31, 2014, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $58.7 million and $74.1 million at March 31, 2015 and Dec. 31, 2014, 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, 2015 and Dec. 31, 2014:

	March 31, 2015				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$20,836	$20,836	$—	$—	$20,836
Commingled funds	470,810	—	489,704	—	489,704
International equity funds	123,123	—	120,608	—	120,608
Private equity investments	86,318	—	—	113,619	113,619
Real estate	46,339	—	—	67,774	67,774
Debt securities:					
Government securities	24,188	—	23,796	—	23,796
U.S. corporate bonds	64,574	—	60,712	—	60,712
International corporate bonds	16,429	—	16,234	—	16,234
Municipal bonds	201,125	—	206,814	—	206,814
Asset-backed securities	2,828	—	2,847	—	2,847
Mortgage-backed securities	12,292	—	12,787	—	12,787
Equity securities:					
Common stock	395,104	601,714	—	—	601,714
Total	$1,463,966	$622,550	$933,502	$181,393	$1,737,445

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $81.8 million of equity investments in unconsolidated subsidiaries and $48.2 million of miscellaneous investments.

	Dec. 31, 2014				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$24,184	$24,184	$—	$—	$24,184
Commingled funds	470,013	—	465,615	—	465,615
International equity funds	80,454	—	78,721	—	78,721
Private equity investments	73,936	—	—	101,237	101,237
Real estate	43,859	—	—	64,249	64,249
Debt securities:					
Government securities	30,674	—	28,808	—	28,808
U.S. corporate bonds	81,463	—	77,562	—	77,562
International corporate bonds	16,950	—	16,341	—	16,341
Municipal bonds	242,282	—	249,201	—	249,201
Asset-backed securities	9,131	—	9,250	—	9,250
Mortgage-backed securities	23,225	—	23,895	—	23,895
Equity securities:					
Common stock	369,751	564,858	—	—	564,858
Total	$1,465,922	$589,042	$949,393	$165,486	$1,703,921

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $83.1 million of equity investments in unconsolidated subsidiaries and $45.6 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, 2015 and 2014:

(Thousands of Dollars)	Jan. 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets [a]	March 31, 2015
Private equity investments	$101,237	$12,382	$—	$—	$113,619
Real estate	64,249	3,861	(1,381)	1,045	67,774
Total	$165,486	$16,243	$(1,381)	$1,045	$181,393

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Asset [a]	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

[a] Gains are deferred as a component of the regulatory assets for nuclear decommissioning.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at March 31, 2015:

	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	$—	$—	$—	$23,796	$23,796
U.S. corporate bonds	473	13,627	49,626	(3,014)	60,712
International corporate bonds	—	4,494	11,334	406	16,234
Municipal bonds	716	32,054	35,877	138,167	206,814
Asset-backed securities	—	—	2,847	—	2,847
Mortgage-backed securities	—	—	—	12,787	12,787
Debt securities	$1,189	$50,175	$99,684	$172,142	$323,190

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, 2015, accumulated other comprehensive losses related to interest rate derivatives included $3.1 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, as applicable.

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, vehicle fuel and weather derivatives.

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At March 31, 2015, 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, 2015 and 2014.

At March 31, 2015, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net losses 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, 2015 and Dec. 31, 2014:

(Amounts in Thousands) [a][b]	March 31, 2015	Dec. 31, 2014
Megawatt hours of electricity	30,826	56,361
Million British thermal units of natural gas	465	927
Gallons of vehicle fuel	246	282

[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, 2015 and 2014, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended March 31, 2015				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains 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	$—	$—	$941 [a]	$—	$—
Vehicle fuel and other commodity	(18)	—	26 [b]	—	—
Total	$(18)	$—	$967	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$3,880 [c]
Electric commodity	—	(9,471)	—	(5,123) [d]	—
Natural gas commodity	—	(216)	—	(8,831) [e]	8,991 [e]
Total	$—	$(9,687)	$—	$(13,954)	$12,871

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	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:		Pre-Tax 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	$—	$—	$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)

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to operating and maintenance (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, 2015 and 2014 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, 2015 and 2014 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, 2015 and 2014. 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, 2015, five of Xcel Energy's 10 most significant counterparties for these activities, comprising $53.0 million or 19 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's Ratings Services, Moody's Investor Services or Fitch Ratings. The remaining five significant counterparties, comprising $63.0 million or 23 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 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. At March 31, 2015 and Dec. 31, 2014, there were no derivative instruments in a liability position that would have required the posting of collateral or settlement of applicable outstanding contracts if the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade.

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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, 2015 and Dec. 31, 2014.

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, 2015:

	March 31, 2015					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$—	$11,369	$2,395	$13,764	$(2,017)	$11,747
Electric commodity	—	—	19,606	19,606	(4,294)	15,312
Total current derivative assets	$—	$11,369	$22,001	$33,370	$(6,311)	27,059
PPAs [a]						11,846
Current derivative instruments						$38,905
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$17,967	$—	$17,967	$(4,129)	$13,838
Total noncurrent derivative assets	$—	$17,967	$—	$17,967	$(4,129)	13,838
PPAs [a]						37,901
Noncurrent derivative instruments						$51,739

	March 31, 2015					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting [b]	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$128	$—	$128	$—	$128
Other derivative instruments:						
Commodity trading	—	5,840	278	6,118	(6,110)	8
Electric commodity	—	—	4,294	4,294	(4,294)	—
Other commodity	—	527	—	527	—	527
Total current derivative liabilities	$—	$6,495	$4,572	$11,067	$(10,404)	663
PPAs [a]						18,952
Current derivative instruments						$19,615
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$85	$—	$85	$—	$85
Other derivative instruments:						
Commodity trading	—	7,541	—	7,541	(7,541)	—
Other commodity	—	51	—	51	—	51
Total noncurrent derivative liabilities	$—	$7,677	$—	$7,677	$(7,541)	136
PPAs [a]						178,821

Noncurrent derivative instruments	$ 178,957

(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, 2015. At March 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $7.5 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, 2014:

(Thousands of Dollars)	Dec. 31, 2014 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$—	$14,326	$4,732	$19,058	$(3,240)	$15,818
Electric commodity	—	—	62,825	62,825	(11,402)	51,423
Natural gas commodity	—	381	—	381	(22)	359
Total current derivative assets	$—	$14,707	$67,557	$82,264	$(14,664)	67,600
PPAs [a]						18,123
Current derivative instruments						$85,723
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$17,617	$—	$17,617	$(4,151)	$13,466
Total noncurrent derivative assets	$—	$17,617	$—	$17,617	$(4,151)	13,466
PPAs [a]						40,309
Noncurrent derivative instruments						$53,775

(Thousands of Dollars)	Dec. 31, 2014 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$118	$—	$118	$—	$118
Other derivative instruments:						
Commodity trading	—	7,974	—	7,974	(7,974)	—
Electric commodity	—	—	11,402	11,402	(11,402)	—
Natural gas commodity	—	548	—	548	(21)	527
Total current derivative liabilities	$—	$8,640	$11,402	$20,042	$(19,397)	645
PPAs [a]						20,987
Current derivative instruments						$21,632
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$102	$—	$102	$—	$102
Other derivative instruments:						
Commodity trading	—	6,890	—	6,890	(6,033)	857
Natural gas commodity	—	35	—	35	—	35
Total noncurrent derivative liabilities	$—	$7,027	$—	$7,027	$(6,033)	994
PPAs [a]						182,942
Noncurrent derivative instruments						$183,936

[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, 2014. At Dec. 31, 2014, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $6.6 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents the changes in Level 3 commodity derivatives for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31	
(Thousands of Dollars)	2015	2014
Balance at Jan. 1	$56,155	$41,660
Purchases	5,792	1,056
Settlements	(19,931)	(53,809)
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	60	999
(Losses) gains recognized as regulatory assets and liabilities	(24,647)	34,311
Balance at March 31	$17,429	$24,217

[(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, 2015 and 2014.

Fair Value of Long-Term Debt

As of March 31, 2015 and Dec. 31, 2014, other financial instruments for which the carrying amount did not equal fair value were as follows:

	March 31, 2015		Dec. 31, 2014	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$11,756,869	$13,619,322	$11,757,360	$13,360,236

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, 2015 and Dec. 31, 2014, 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)	2015	2014
Interest income	$4,238	$3,893
Other nonoperating income	968	1,116
Insurance policy expense	(2,045)	(1,808)
Other income, net	$3,161	$3,201

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 primarily in portions of Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy’s regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

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- 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 $81.8 million and $83.1 million as of March 31, 2015 and Dec. 31, 2014, 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, 2015					
Operating revenues from external customers	$2,224,863	$715,996	$21,360	$—	$2,962,219
Intersegment revenues	330	676	—	(1,006)	—
Total revenues	$2,225,193	$716,672	$21,360	$(1,006)	$2,962,219
Net income (loss)	$81,021 [a]	$83,676	$(12,631)	$—	$152,066

(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

[a] Includes a net of tax charge related to the Monticello LCM/EPU project. See Note 5.

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 using 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.

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.

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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, 2015			Three Months Ended March 31, 2014		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$152,066			$261,221		
Basic EPS:						
Earnings available to common shareholders	152,066	506,983	$0.30	261,221	499,523	$0.52
Effect of dilutive securities:						
Time based equity awards	—	410		—	223	
Diluted EPS:						
Earnings available to common shareholders	$152,066	507,393	$0.30	$261,221	499,746	$0.52

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended March 31			
	2015	2014	2015	2014
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$24,828	$22,086	$529	$864
Interest cost	37,131	39,155	6,324	8,507
Expected return on plan assets	(53,473)	(51,801)	(6,650)	(8,489)
Amortization of prior service credit	(451)	(437)	(2,672)	(2,672)
Amortization of net loss	31,288	29,191	1,351	2,935
Net periodic benefit cost (credit)	39,323	38,194	(1,118)	1,145
Costs not recognized due to the effects of regulation	(7,496)	(7,052)	—	—
Net benefit cost (credit) recognized for financial reporting	$31,827	$31,142	$(1,118)	$1,145

In January 2015, contributions of $90.0 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2015.

13. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the three months ended March 31, 2015 and 2014 were as follows:

	Three Months Ended March 31, 2015			
(Thousands of Dollars)	Gains and Losses	Unrealized Gains on Marketable	Defined Benefit Pension and	Total

	on Cash Flow Hedges	Securities	Postretirement Items	
Accumulated other comprehensive (loss) income at Jan. 1	$(57,628)	$110	$(50,621)	$(108,139)
Other comprehensive (loss) income before reclassifications	(11)	1	—	(10)
Losses reclassified from net accumulated other comprehensive loss	585	—	876	1,461
Net current period other comprehensive income	574	1	876	1,451
Accumulated other comprehensive (loss) income at March 31	$(57,054)	$111	$(49,745)	$(106,688)

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(Thousands of Dollars)	Three Months Ended March 31, 2014 Gains and Losses on Cash Flow Hedges	Unrealized Gains on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$(59,753)	$77	$(46,599)	$(106,275)
Other comprehensive (loss) income 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 (loss) income at March 31	$(59,200)	$115	$(45,735)	$(104,820)

Reclassifications from accumulated other comprehensive loss for the three months ended March 31, 2015 and 2014 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$941	(a)	$946	(a)
Vehicle fuel derivatives	26	(b)	(28)	(b)
Total, pre-tax	967		918	
Tax benefit	(382)		(358)	
Total, net of tax	585		560	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	1,535	(c)	1,500	(c)
Prior service credit	(90)	(c)	(86)	(c)
Transition obligation	—	(c)	—	(c)
Total, pre-tax	1,445		1,414	
Tax benefit	(569)		(550)	
Total, net of tax	876		864	
Total amounts reclassified, net of tax	$1,461		$1,424	

(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.

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

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

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Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2015 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 slowdown 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; cyber security threats and data security breaches; 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 Operations in Item 7 of Xcel Energy Inc.’s Form 10-K for the year ended Dec. 31, 2014; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including Risk Factors in Item 1A and Exhibit 99.01 of Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2014, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2015.

Financial Review

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted 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 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 Xcel Energy’s core earnings and underlying performance. We believe this measurement is useful to investors in facilitating period over period comparisons and evaluating or projecting financial results. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended March 31	
Diluted Earnings (Loss) Per Share	2015	2014
PSCo	$0.22	$0.24

NSP-Minnesota	0.16	0.21
NSP-Wisconsin	0.05	0.05
SPS	0.04	0.04
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility	0.48	0.55
Xcel Energy Inc. and other	(0.02)	(0.03)
Ongoing diluted EPS	0.46	0.52
Loss on Monticello LCM/EPU project	(0.16)	—
GAAP diluted EPS	$0.30	$0.52

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Earnings Adjusted for Certain Items (Ongoing Earnings)

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

First quarter 2015 GAAP earnings included a $0.16 per share charge related to the Monticello nuclear facility LCM/EPU project, which in total cost $748 million. In March 2015, the MPUC approved full recovery, including a return, on $415 million of the project costs, inclusive of AFUDC, but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment for years 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately $129 million. See Note 5 to the consolidated financial statements for further discussion.

Summary of Ongoing Earnings

Xcel Energy — First quarter 2015 ongoing earnings, which exclude an adjustment for a charge related to the Monticello LCM/EPU project, decreased $0.06 per share for the first quarter of 2015. The decrease in ongoing earnings was largely attributable to the negative impact of weather. The extreme cold weather experienced in the first quarter of 2014 positively impacted earnings by approximately $0.05 per share. The weather in 2015 was closer to normal, resulting in a net negative variance when comparing periods. Other factors include higher depreciation, operating and maintenance expenses, property taxes and lower allowance for funds used during construction. These amounts were partially offset by earnings from higher electric margins due to new rates and riders in various jurisdictions.

PSCo — PSCo's ongoing earnings decreased $0.02 per share for the first quarter of 2015. The positive impact of implementing the CACJA rider, effective Jan. 1, 2015, and the recognition of lower estimated electric earnings test refunds were offset by lower AFUDC, higher property taxes, O&M expenses, depreciation and the unfavorable impact of weather ($0.01 per share).

NSP-Minnesota — NSP-Minnesota's ongoing earnings decreased $0.05 per share for the first quarter of 2015. Higher revenue attributable to electric rate cases in North Dakota and South Dakota (interim, subject to refund) were more than offset by the impact of increases in depreciation and O&M expenses as well as unfavorable weather. The colder weather experienced in 2014 resulted in a $0.03 per share decrease when comparing periods. In the first quarter of 2015, NSP-Minnesota recorded electric revenue in Minnesota consistent with interim rates, which were implemented in January 2014, as the MPUC has not issued its final rate case order or ruled on its treatment of interim rates. A true-up reflecting an additional $10.5 million of first quarter revenue would be recorded later in the year, if the MPUC approves NSP-Minnesota's proposed treatment of the 2014 refund for interim rates.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings were flat for the first quarter of 2015. Lower O&M expenses and higher electric margins, primarily due to an electric rate increase, were offset by the unfavorable impact of weather ($0.01 per share) and higher depreciation.

SPS — SPS' ongoing earnings were flat for the first quarter of 2015. Higher electric rates in Texas and New Mexico were offset by higher depreciation and O&M expenses.

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Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2015 EPS compared with the same period in 2014. See further discussion below.

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
2014 GAAP and ongoing diluted EPS	$0.52
Components of change — 2015 vs. 2014	
Higher electric margins	0.05
Lower conservation and DSM program expenses (offset by lower revenues)	0.03
Higher depreciation and amortization	(0.03)
Higher O&M expenses	(0.03)
Higher ETR	(0.02)
Lower AFUDC — equity	(0.02)
Lower natural gas margins	(0.01)
Higher taxes (other than income taxes)	(0.01)
Higher interest charges	(0.01)
Dilution from equity issued through the at-the-market program, direct stock purchase plan and benefit plans	(0.01)
2015 ongoing diluted EPS	0.46
Loss on Monticello LCM/EPU project	(0.16)
2015 GAAP diluted EPS	$0.30

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

	Three Months Ended March 31	
(Millions of Dollars)	2015	2014
GAAP income (loss) by segment		
Regulated electric income	$81.0	$185.4
Regulated natural gas income	83.7	77.3
Other (loss) income [(a)]	(2.2)	11.4
Xcel Energy Inc. and other [(a)]	(10.4)	(12.9)
Total net income	$152.1	$261.2

	Three Months Ended March 31	
Contributions to Diluted Earnings (Loss) Per Share	2015	2014
GAAP earnings (loss) by segment		
Regulated electric	$0.16	$0.37
Regulated natural gas	0.16	0.16
Other [(a)]	—	0.02
Xcel Energy Inc. and other [(a)]	(0.02)	(0.03)
Total diluted EPS	$0.30	$0.52

[(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 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.

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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. 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 regulatory practice. 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 2015 due to THI or CDD. The percentage (decrease) increase in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
HDD	(1.1)%	14.1 %	(13.5)%

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		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
Retail electric	$(0.001)	$0.031	$(0.032)
Firm natural gas	(0.004)	0.018	(0.022)
Total	$(0.005)	$0.049	$(0.054)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2015:

	Three Months Ended March 31				
	Xcel Energy	SPS	NSP-Wisconsin	PSCo	NSP-Minnesota
Actual					
Electric residential [a]	(4.9)%	(3.1)%	(7.7)%	(3.3)%	(6.3)%
Electric commercial and industrial	—	1.9	1.5	0.4	(1.7)
Total retail electric sales	(1.5)	0.8	(1.6)	(0.8)	(3.1)
Firm natural gas sales	(10.1)	N/A	(9.3)	(9.6)	(11.1)

	Three Months Ended March 31				
	Xcel Energy	SPS	NSP-Wisconsin	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential [a]	(0.5)%	2.0 %	(1.2)%	(1.0)%	(0.7)%
Electric commercial and industrial	0.9	2.0	3.1	1.1	(0.4)
Total retail electric sales	0.5	1.9	1.7	0.4	(0.5)
Firm natural gas sales	2.9	N/A	6.5	2.0	3.9

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

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Weather-normalized Electric Growth (Decline)

- SPS' commercial and industrial (C&I) growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area. Residential growth reflects an increased number of customers as well as greater use per customer.
- NSP-Wisconsin's electric sales growth was largely due to strong sales to large C&I customers primarily in the oil, gas and sand mining industries. Residential decline was primarily attributable to lower use per customer.
- PSCo's C&I growth was primarily due to expansion in the health care and technology services industries. Residential decrease was primarily the result of weaker use per customer, partially offset by customer growth.
- NSP-Minnesota's C&I electric sales declined as a result of lower use for large customers (primarily due to a decline in usage by the service industry), partially offset by an increase in the number of customers in both the small and large classes. Residential decrease was due to less use per customer, partially offset by increasing customer growth.

Weather-normalized Natural Gas Growth

- Across all natural gas service territories, increased natural gas sales were fueled by both customer growth and higher use per customer. Low natural gas prices and continued economic recovery drove gains from both residential and C&I customers. In addition, NSP-Minnesota and NSP-Wisconsin experienced growth from customers converting from propane to natural gas and customers in the sand mining industry.

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 minimal impact on electric margin. The following table details the electric revenues and margin:

	Three Months Ended March 31	
(Millions of Dollars)	2015	2014
Electric revenues	$2,225	$2,302
Electric fuel and purchased power	(950)	(1,067)
Electric margin	$1,275	$1,235

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 2015 vs. 2014
Fuel and purchased power cost recovery	$(110)
Estimated impact of weather	(25)
Conservation and DSM program revenues (offset by expenses)	(16)
Trading	(8)
Non-fuel riders [(a) (b)]	34
Retail rate increases [(b) (c)]	23
Earnings test refund	11
Transmission revenue	8

Other, net	6
Total decrease in electric revenues	$(77)

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Electric Margin

(Millions of Dollars)	Three Months Ended March 31 2015 vs. 2014
Non-fuel riders [a] [b]	$34
Retail rate increases [b] [c]	23
Earnings test refund	11
Transmission revenue, net of costs	7
NSP-Wisconsin fuel recovery	7
Estimated impact of weather	(25)
Conservation and DSM program revenues (offset by expenses)	(16)
Other, net	(1)
Total increase in electric margin	$40

(a) Increase relates primarily to the new CACJA rider in Colorado ($24 million), effective Jan. 1, 2015, and TCR rider in Minnesota ($9 million).

(b) Non-fuel rider amounts for the CACJA rider in Colorado (allowed for in the settlement) positively impacted revenues and more than offset the base rate decrease. See Note 5 to the consolidated financial statements.

(c) Increase due to rate proceedings in Texas, Minnesota, New Mexico, Wisconsin and North Dakota and the interim rates associated with the pending South Dakota case, subject to and net of an estimated provision for refund. These increases were slightly offset by a decline in Colorado retail base rates which occurred as a result of the recent CPUC decision.

Natural Gas Revenues and Margin

Total natural gas expense 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)	2015	2014
Natural gas revenues	$716	$880
Cost of natural gas sold and transported	(472)	(624)
Natural gas margin	$244	$256

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 2015 vs. 2014
Purchased natural gas adjustment clause recovery	$(150)
Estimated impact of weather	(17)
Conservation and DSM program revenues (offset by expenses)	(7)
Integrity rider (Colorado) and infrastructure rider (Minnesota), partially offset in expenses	7

Retail sales growth, excluding weather impact	4
Other, net	(1)
Total decrease in natural gas revenues	$(164)

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Natural Gas Margin

(Millions of Dollars)	Three Months Ended March 31 2015 vs. 2014
Estimated impact of weather	$(17)
Conservation and DSM program revenues (offset by expenses)	(7)
Integrity rider (Colorado) and infrastructure rider (Minnesota), partially offset in expenses	7
Retail sales growth, excluding weather impact	4
Other, net	1
Total decrease in natural gas margin	$(12)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $25.7 million, or 4.6 percent, for the first quarter of 2015 compared with the same period in 2014. O&M expenses were higher for the quarter, primarily due to the timing of planned maintenance and overhauls at a number of our generation facilities. We continue to expect that the change in annual O&M expense for 2015 to be within a range of 0 percent to 2 percent, consistent with our annual guidance assumptions.

(Millions of Dollars)	Three Months Ended March 31 2015 vs. 2014
Plant generation costs	$17
Nuclear plant operations	4
Employee benefits	4
Other, net	1
Total increase in O&M expenses	$26

Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased $23.7 million, or 30.6 percent, for the first quarter of 2015 compared with the same period in 2014. The decrease was primarily attributable to lower electric and gas recovery rates at NSP-Minnesota and PSCo. Therefore, lower expenses are generally offset by lower revenues.

Depreciation and Amortization — Depreciation and amortization increased $27.2 million, or 11.0 percent, for the first quarter of 2015 compared with the same period in 2014. The increase was primarily attributed to normal system expansion and lower amortization of the excess depreciation reserve in Minnesota. See further discussion within Note 5.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $11.9 million, or 9.6 percent, for the first quarter of 2015 compared with the same period in 2014. The increase was due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC decreased $12.7 million for the first quarter of 2015 compared with the same period in 2014. The decrease was primarily due to the implementation of the CACJA rider on Jan. 1, 2015, facilitating earlier and alternative recovery of construction costs.

Interest Charges — Interest charges increased $5.8 million, or 4.2 percent, for the first quarter of 2015 compared with the same period in 2014. The increase was primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $52.2 million for the first quarter of 2015 compared with the same period in 2014. The decrease was primarily due to lower 2015 pretax earnings, partially offset by decreased permanent plant-related adjustments in 2015 and the successful resolution of a 2010-2011 IRS audit issue in 2014. The ETR was 35.5 percent for the first quarter of 2015 compared with 34.2 percent for the same period in 2014. The lower ETR for 2014 was primarily due to the adjustments referenced above.

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Public Utility Regulation

NSP-Minnesota

NSP-Minnesota – Courtenay Wind Farm — In 2013, NSP-Minnesota signed a purchase power agreement with a developer for the Courtenay wind farm, a 200 megawatt project in North Dakota. Since that time, the developer is seeking to exit the project due to a lack of financial wherewithal. Courtenay was originally scheduled for commercial operation in 2014, but significant site construction on the project has not commenced. As a result, NSP-Minnesota has negotiated an agreement to acquire the development rights for the project and is seeking to preserve other benefits of the project by curing the developer's default under a generator interconnection agreement, which is critical to timely construction of the project, and which we expect will be resolved between the parties or by the FERC by the end of May. After regulatory approval of the transaction, NSP-Minnesota plans to move forward with construction and will ultimately own the facility as part of rate base. In May 2015, NSP-Minnesota anticipates filing for expedited regulatory approval in Minnesota and North Dakota, so that construction can begin in late summer. The total construction cost of the project is estimated to be approximately $300 million with project completion by the end of 2016. Courtenay is not currently included in Xcel Energy’s five-year capital forecast. Xcel Energy does not expect to issue any additional equity to finance the project.

NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Resource Plan with the MPUC, proposing to achieve a 40 percent reduction in carbon emissions by 2030 from 2005 levels through the significant addition of renewables, continued commitment to specific critical infrastructure protection annual achievements, and the continued operation of its existing cost-effective thermal generation. In March 2015, NSP-Minnesota supplemented the plan to reflect (1) the resource additions that resulted from its Competitive Acquisition Plan (CAP) to meet an identified resource need in the 2018-2020 timeframe, (2) significantly higher than expected response to its Community Solar Gardens program, and (3) additional early Sherco 1 and 2 retirement scenarios. The updated resource plan continues to position NSP-Minnesota to be responsive to future environmental requirements and market trends, builds on the significant investments already made in the NSP System, and acknowledges the divergence in state energy policies within the NSP System. Key points of the resource plan include:

- Adding 600 MW of wind by 2020 and an additional 1,200 MW by 2027, bringing total wind power on the NSP System to over 3,600 MW;
- Adding 187 MW of large-scale solar energy by 2016 and an additional 1,700 MW of large-scale solar and 500 MW of customer-driven small-scale solar; bringing total solar power on the NSP System to approximately 2,400 MW;
- Operating the Monticello and PI nuclear plants through their current licenses; and
- Continuing to run Sherco Units 1 and 2 with gradually decreasing reliance through 2030.

The additional CAP resources approved by the MPUC in February 2015 are as follows:

- Enter into an agreement for 100 MW of distributed solar with Geronimo Energy LLC;
- Enter into an agreement with Calpine Corporation for a 345 MW expansion at its Mankato Energy Center; and
- Construct a 215 MW Black Dog Unit 6 combustion turbine.

In February 2015 the MPUC approved the CAP subject to several requests for clarification and/or reconsideration, which are pending with the MPUC.

NSP-Minnesota also proposed use of a collaborative stakeholder process to guide its five-year action plan. In addition to requesting a planning meeting with the MPUC, it conducted the first in a series of stakeholder workshops in February 2015.

CapX2020 — The estimated cost of the five major CapX2020 transmission projects listed below is $2 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total investment. As of March 31, 2015, Xcel Energy has invested $911.2 million of its $1.1 billion share of the five CapX2020 transmission projects.

Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 161/345 Kilovolt (KV) transmission line
Construction on the 156-mile project started in Minnesota in January 2013 and the project is expected to go into service in the fall of 2016, although segments are being placed in service as they are completed.

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. In April 2014, the St. Cloud, Minn. to Alexandria, Minn. portion of the project was placed in service. In April 2015, the final portion of the project between Alexandria, Minn. and Fargo, N.D. was placed in service.

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Brookings County, S.D. to Hampton, Minn. 345 KV transmission line
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 was placed in service in March 2015.

Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line
The 70-mile 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 — Minnesota legislation requires 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 20 kilowatts or less. NSP-Minnesota anticipates it will meet its compliance requirements through large and small scale solar additions. NSP-Minnesota plans to add 287 MWs of large-scale solar to its system by the end of 2016. Additionally, NSP-Minnesota offers small solar programs: a community solar garden program that provides bill credits to participating subscribers, and a solar production incentive program for rooftop solar. NSP-Minnesota launched both its Solar*Rewards incentive program and its Solar*Rewards Community programs in 2014. Additionally, the Department of Commerce launched its Made in Minnesota incentive program for small solar in 2014, which generates renewable energy credits for NSP-Minnesota.

By early 2015, NSP-Minnesota received more than 500 MWs of proposals for community solar gardens. NSP-Minnesota sought policy guidance from the MPUC regarding the price and size of community solar projects proposed in its service territory, as the established community solar pricing structure was intended for small projects one MW or less. In contrast, the Solar*Rewards Community proposals are sized between 10 and 50 MWs. The MPUC is expected to review the program in the second quarter of 2015.

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. See Note 14 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2014 for further discussion regarding the nuclear generating plants.

Nuclear Regulatory Performance — The NRC has a Reactor Oversight Process that classifies U.S. nuclear reactors into various categories (referred to as Columns, from 1 to 5) based on the significance of issues identified in performance indicators or inspection findings. Such issues are evaluated as either green, white, yellow, or red based on their safety significance, with green representing the least safety concern and red representing the most concern. At Dec. 31, 2014, PI Units 1 and 2 were in Column 1 (licensee response) with all green performance indicators and no greater than green findings or violations. Monticello was in Column 3 (degraded cornerstone) with all green performance indicators, a yellow finding related to flood control and a potentially greater than green finding related to plant security which was immediately remedied. The NRC informed Xcel Energy in February 2015 that the final determination on the security finding was greater than green. The NRC notified Xcel Energy in March 2015 that Monticello was upgraded from Column 3 (degraded cornerstone) to Column 2 (regulatory response). The upgrade recognized the plant's response to the flooding issue and associated yellow finding and the NRC's inspection and close out of the yellow finding. Monticello is in Column 2 and will remain there until the NRC can perform an inspection and close the white security finding that was identified in 2014.

NSP-Wisconsin

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. NSP-Wisconsin's half of the line will be shared with three partners, Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Association-Wisconsin. In 2011, MISO determined the line to be a MVP project, and as such, eligible for cost sharing under MISO's MVP tariff.

In April 2015, the PSCW issued its order approving a CPCN and route for the project. The 180-mile project will cost approximately $580 million. NSP-Wisconsin's portion of the investment is estimated to be approximately $207 million. 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 Generating Station, near Brush, Colo. and terminating at the Daniels Park substation, near Castle Pines, Colo. The estimated cost of the project is $178 million. In November 2014, the ALJ issued a recommended decision approving the CPCN, but delaying construction until May 2020. The CPUC denied all exceptions to the ALJs recommended decision, clarifying that while construction may begin in May 2020, local permit applications and land acquisition may begin immediately.

Net Metering Standard — In a filing, PSCo proposed to track and quantify the system costs that are not avoided by distributed solar generation, which PSCo has defined as a "net metering incentive," for purposes of equitably recovering costs between customers. The CPUC assigned the net metering issue to its own docket and is conducting a series of panel discussions to gain a better understanding of net metering issues. A CPUC decision is anticipated in the third quarter of 2015.

Boulder, Colo. Municipalization — PSCo's franchise agreement with the City of Boulder (Boulder) expired in December 2010. In November 2011, a ballot measure was passed which authorized the formation and operation of a municipal utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage. In May 2014, the Boulder City Council passed an ordinance to establish an electric utility.

In 2013, the CPUC ruled that it has jurisdiction under Colorado law to determine the utility that will serve customers outside Boulder's city limits, and will determine certain system separation matters as well as what facilities need to be constructed to ensure reliable service. The CPUC has declared that it should make its determinations prior to any eminent domain actions. In January 2014, Boulder appealed this ruling to the Boulder District Court. In January 2015, the Boulder District Court affirmed the CPUC decision.

Boulder sent PSCo an offer of $128 million for certain portions of PSCo's transmission and distribution business. PSCo has notified Boulder that its offer was deficient. Under Colorado law, a condemning entity must pay the owner fair market value for the taking of and damages to the remainder of the property.

In July 2014, Boulder filed a petition for condemnation in the Boulder District Court. PSCo filed a motion to dismiss the petition based upon the CPUC's ruling that it must determine the appropriate system separations prior to Boulder filing its condemnation case. PSCo's motion to dismiss was granted in February 2015. This decision does not prevent Boulder from filing another condemnation petition after it obtains CPUC approval of its separation plan, which is anticipated to be filed no earlier than the second quarter of 2015.

In August 2014, PSCo filed a petition with the FERC requesting an order requiring that Boulder's attempt to acquire PSCo's transmission and distribution facilities by condemnation requires prior FERC approval under the Federal Power Act. In December 2014, the FERC issued an order granting PSCo's petition.

If Boulder proceeds with another condemnation petition and were to succeed in the eminent domain proceeding, PSCo would 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.

On April 16, 2015, Boulder issued a request for proposal for a partial requirements wholesale electric power supply agreement. Boulder indicated that the request for proposal was designed to elicit a wholesale power supply arrangement for a five-year term commencing on Jan. 1, 2018. Boulder has requested that PSCo consider different pricing structures, and allow for Boulder to reduce demand over the term of the contract. Boulder requested a response by May 18, 2015.

Steam System Package Boilers and Regulatory Plan — In December 2014, PSCo filed the results of a steam survey along with both a short-term plan and a long-term plan for the steam system consisting of a request for a conditional CPCN to construct either one or two boilers for its steam utility, dependent on the next two seasons of winter peaking capacity. On April 1, 2015, PSCo filed with the CPUC a settlement agreement among all parties resolving all issues. A CPUC decision is anticipated in the second quarter of 2015.

Cabin Creek Hydro Upgrade — PSCo plans to file a CPCN with the CPUC in May 2015 to upgrade the Cabin Creek Hydro facility. The upgrade is estimated to cost $89.2 million and will extend the life of the facility by 40 years as well as increase the maximum output by 36 MW.

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SPS

SPS Transmission Notifications to Construct (NTC) — As a member of SPP, SPS accepts NTCs for electric transmission line and substation projects to be built within the SPP footprint. SPS has accepted NTCs for projects with an estimated capital cost of approximately $1.9 billion and will continue to review new NTCs for acceptance as they are issued. These projects generally span several years to plan, site, procure and develop. The New Mexico Public Regulatory Commission (NMPRC) and the PUCT must approve the siting and routing of any SPP identified transmission line NTC projects that require permitting approval. Projects identified through SPP NTCs may have costs allocated to other SPP members in accordance with the SPP Open Access Transmission Tariff (OATT). Costs allocated to SPS are permissible for recovery through the NMPRC, the PUCT and the FERC processes.

Chaves County, N.M. Solar Contracts — In March 2015, SPS entered into two purchased energy contracts with NextEra Resources for the purchase of solar generated electricity from two 70 MW projects to be constructed in Chaves County, N.M.. The two 25-year contracts are subject to regulatory approval and they are now pending review and approval by the NMPRC. The purchased energy will be recovered from customers through SPS’ fuel and purchased energy cost recovery mechanisms.

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, asset transactions and mergers, accounting practices and certain other activities of Xcel Energy Inc.’s utility subsidiaries and transmission-only subsidiaries, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.’s utility subsidiaries’ activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2014. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Order, New ROE Policy — In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In October 2014, the FERC upheld the determination of the long-term growth rate to be used in its new ROE methodology. In March 2015, the FERC issued an order on rehearing upholding use of the new ROE methodology.

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks in the normal course of business. 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.

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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, 2015, 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	$5,340	$8,551	$1,047	$829	$15,767
NSP-Minnesota	2	1,750	—	—	—	1,750
PSCo	1	189	—	—	—	189
		$7,279	$8,551	$1,047	$829	$17,706

	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	$366	$—	$—	$—	$366

(a) — Prices actively quoted or based on actively quoted prices.
(b) — 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)	2015	2014
Fair value of commodity trading net contract assets outstanding at Jan. 1	$21,811	$30,514
Contracts realized or settled during the period	3,256	(6,585)
Commodity trading contract additions and changes during period	(6,995)	1,599
Fair value of commodity trading net contract assets outstanding at March 31	$18,072	$25,528

At March 31, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1.5 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1.5 million. At March 31, 2014, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.1 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.1 million.

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

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

(Millions of Dollars)	Three Months Ended March 31	VaR Limit	Average	High	Low
2015	$0.47	$3.00	$0.23	$0.32	