XCEL ENERGY INC
Form 10-Q
July 31, 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 June 30, 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 ¨ (Do not check if smaller reporting company)	Smaller reporting company ¨

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

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

Class	Outstanding at July 27, 2015
Common Stock, $2.50 par value	507,211,342 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 June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Operating revenues				
Electric	$2,213,460	$2,297,638	$4,438,323	$4,599,348
Natural gas	284,131	369,127	1,000,127	1,248,815
Other	17,543	18,331	38,903	39,537
Total operating revenues	2,515,134	2,685,096	5,477,353	5,887,700
Operating expenses				
Electric fuel and purchased power	904,705	1,041,322	1,854,837	2,108,643
Cost of natural gas sold and transported	126,667	210,901	599,038	834,729
Cost of sales — other	8,164	7,642	18,213	16,771
Operating and maintenance expenses	594,279	585,604	1,180,109	1,145,747
Conservation and demand side management program expenses	54,141	70,834	107,946	148,380
Depreciation and amortization	274,602	255,307	547,700	501,250
Taxes (other than income taxes)	129,731	116,278	266,357	240,980
Loss on Monticello life cycle management/extended power uprate project	—	—	129,463	—
Total operating expenses	2,092,289	2,287,888	4,703,663	4,996,500
Operating income	422,845	397,208	773,690	891,200
Other income, net	961	82	4,122	3,283
Equity earnings of unconsolidated subsidiaries	8,422	7,811	16,198	15,249
Allowance for funds used during construction — equity	12,641	23,608	25,301	45,515
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,861, $5,614, $11,559 and $11,406, respectively	144,222	139,400	289,162	278,494
Allowance for funds used during construction — debt	(6,165)	(10,113)	(12,309)	(19,661)
Total interest charges and financing costs	138,057	129,287	276,853	258,833
Income before income taxes	306,812	299,422	542,458	696,414
Income taxes	109,881	104,258	193,461	240,029
Net income	$196,931	$195,164	$348,997	$456,385
Weighted average common shares outstanding:				
Basic	507,707	503,272	507,359	501,408
Diluted	508,074	503,456	507,747	501,612

Earnings per average common share:				
Basic	$0.39	$0.39	$0.69	$0.91
Diluted	0.39	0.39	0.69	0.91
Cash dividends declared per common share	$0.32	$0.30	$0.64	$0.60

See Notes to Consolidated Financial Statements

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

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Net income	$196,931	$195,164	$348,997	$456,385
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $561, $550, $1,130 and $1,099, respectively	883	864	1,759	1,728
Derivative instruments:				
Net fair value increase, net of tax of $11, $9, $4 and $6, respectively	18	16	7	8
Reclassification of losses to net income, net of tax of $382, $365, $764 and $722, respectively	600	574	1,185	1,135
	618	590	1,192	1,143
Marketable securities:				
Net fair value increase, net of tax of $1, $0, $1 and $24, respectively	1	—	2	38
Other comprehensive income	1,502	1,454	2,953	2,909
Comprehensive income	$198,433	$196,618	$351,950	$459,294

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

	Six Months Ended June 30	
	2015	2014
Operating activities		
Net income	$348,997	$456,385
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	556,420	509,914
Conservation and demand side management program amortization	2,901	3,131
Nuclear fuel amortization	49,454	60,466
Deferred income taxes	191,164	236,479
Amortization of investment tax credits	(2,768)	(2,886)
Allowance for equity funds used during construction	(25,301)	(45,515)
Equity earnings of unconsolidated subsidiaries	(16,198)	(15,249)
Dividends from unconsolidated subsidiaries	19,754	18,114
Share-based compensation expense	21,420	10,990
Loss on Monticello life cycle management/extended power uprate project	129,463	—
Net realized and unrealized hedging and derivative transactions	13,450	(2,403)
Changes in operating assets and liabilities:		
Accounts receivable	150,283	1,406
Accrued unbilled revenues	145,781	77,557
Inventories	64,561	75,268
Other current assets	69,080	(32,157)
Accounts payable	(132,032)	(147,734)
Net regulatory assets and liabilities	129,595	63,675
Other current liabilities	(92,108)	(129,981)
Pension and other employee benefit obligations	(78,681)	(115,455)
Change in other noncurrent assets	684	47,855
Change in other noncurrent liabilities	(36,874)	(30,349)
Net cash provided by operating activities	1,509,045	1,039,511
Investing activities		
Utility capital/construction expenditures	(1,477,959)	(1,575,748)
Proceeds from insurance recoveries	27,237	6,000
Allowance for equity funds used during construction	25,301	45,515
Purchases of investments in external decommissioning fund	(640,100)	(404,780)
Proceeds from the sale of investments in external decommissioning fund	636,669	401,488
Investment in WYCO Development LLC	(764)	(2,132)
Other, net	(1,407)	(1,568)
Net cash used in investing activities	(1,431,023)	(1,531,225)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(568,500)	18,800
Proceeds from issuance of long-term debt	841,534	838,582
Repayments of long-term debt	(454)	(275,484)
Proceeds from issuance of common stock	3,409	176,573
Dividends paid	(298,022)	(274,361)

Net cash (used in) provided by financing activities	(22,033)	484,110
Net change in cash and cash equivalents	55,989	(7,604)
Cash and cash equivalents at beginning of period	79,608	107,144
Cash and cash equivalents at end of period	$135,597	$99,540
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(266,840)	$(251,461)
Cash received (paid) for income taxes, net	58,598	(4,704)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$206,540	$305,447
Issuance of common stock for reinvested dividends and 401(k) plans	30,498	29,272

See Notes to Consolidated Financial Statements

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

	June 30, 2015	Dec. 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$135,597	$79,608
Accounts receivable, net	676,223	826,506
Accrued unbilled revenues	582,711	728,492
Inventories	532,703	597,183
Regulatory assets	364,746	444,058
Derivative instruments	63,603	85,723
Deferred income taxes	429,860	246,210
Prepaid taxes	121,705	185,488
Prepayments and other	141,774	171,112
Total current assets	3,048,922	3,364,380
Property, plant and equipment, net	29,350,364	28,756,916
Other assets		
Nuclear decommissioning fund and other investments	1,880,153	1,832,640
Regulatory assets	2,759,892	2,774,216
Derivative instruments	53,306	53,775
Other	176,172	175,957
Total other assets	4,869,523	4,836,588
Total assets	$37,268,809	$36,957,884
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$707,356	$257,726
Short-term debt	451,000	1,019,500
Accounts payable	830,278	1,173,006
Regulatory liabilities	418,618	410,729
Taxes accrued	280,838	396,615
Accrued interest	160,146	158,536
Dividends payable	162,224	151,720
Derivative instruments	26,845	21,632
Other	499,946	475,119
Total current liabilities	3,537,251	4,064,583
Deferred credits and other liabilities		
Deferred income taxes	6,249,511	5,852,988
Deferred investment tax credits	70,928	73,696
Regulatory liabilities	1,176,806	1,163,429
Asset retirement obligations	2,517,668	2,446,631
Derivative instruments	171,691	183,936
Customer advances	241,546	256,945

Pension and employee benefit obligations	858,450	936,907
Other	279,766	264,653
Total deferred credits and other liabilities	11,566,366	11,179,185
Commitments and contingencies		
Capitalization		
Long-term debt	11,896,126	11,499,634
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 506,959,395 and 505,733,267 shares outstanding at June 30, 2015 and Dec. 31, 2014, respectively	1,267,398	1,264,333
Additional paid in capital	5,863,209	5,837,330
Retained earnings	3,243,645	3,220,958
Accumulated other comprehensive loss	(105,186)	(108,139)
Total common stockholders' equity	10,269,066	10,214,482
Total liabilities and equity	$37,268,809	$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 June 30, 2015 and 2014						
Balance at March 31, 2014	501,152	$1,252,879	$5,681,150	$2,918,215	$ (104,820)	$9,747,424
Net income				195,164		195,164
Other comprehensive income					1,454	1,454
Dividends declared on common stock				(151,973)		(151,973)
Issuances of common stock	3,954	9,885	111,053			120,938
Share-based compensation			7,765			7,765
Balance at June 30, 2014	505,106	$1,262,764	$5,799,968	$2,961,406	$ (103,366)	$9,920,772
Balance at March 31, 2015	506,664	$1,266,659	$5,844,995	$3,209,904	$ (106,688)	$10,214,870
Net income				196,931		196,931
Other comprehensive income					1,502	1,502
Dividends declared on common stock				(163,190)		(163,190)
Issuances of common stock	295	739	9,316			10,055
Share-based compensation			8,898			8,898
Balance at June 30, 2015	506,959	$1,267,398	$5,863,209	$3,243,645	$ (105,186)	$10,269,066

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Six Months Ended June 30, 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				456,385		456,385
Other comprehensive income					2,909	2,909
Dividends declared on common stock				(302,962)		(302,962)
Issuances of common stock	7,134	17,835	166,825			184,660
Share-based compensation			13,830			13,830
Balance at June 30, 2014	505,106	$1,262,764	$5,799,968	$2,961,406	$ (103,366)	$9,920,772
Balance at Dec. 31, 2014	505,733	$1,264,333	$5,837,330	$3,220,958	$ (108,139)	$10,214,482
Net income				348,997		348,997
Other comprehensive income					2,953	2,953
Dividends declared on common stock				(326,310)		(326,310)
Issuances of common stock	1,226	3,065	10,209			13,274
Share-based compensation			15,670			15,670
Balance at June 30, 2015	506,959	$1,267,398	$5,863,209	$3,243,645	$ (105,186)	$10,269,066

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

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of June 30, 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 and six months ended June 30, 2015 and 2014; and its cash flows for the six months ended June 30, 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 June 30, 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. The new guidance also includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers. As a result of the FASB's deferral of the standard's required implementation date in July 2015, the guidance is effective for interim and annual reporting periods beginning after Dec. 15, 2017. 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.

Fair Value Measurement — In May 2015, the FASB issued Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent), Topic 820 (Accounting Standards Update (ASU) No. 2015-07), which removes the requirement to categorize within the fair value hierarchy the fair values for investments measured using a net asset value methodology. This guidance will be effective on a retrospective basis for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Other than the reduced disclosure requirements, Xcel Energy does not expect the implementation of ASU 2015-07 to have a material impact on its consolidated financial statements.

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3. Selected Balance Sheet Data

(Thousands of Dollars)	June 30, 2015	Dec. 31, 2014
Accounts receivable, net		
Accounts receivable	$726,732	$884,225
Less allowance for bad debts	(50,509)	(57,719)
	$676,223	$826,506

(Thousands of Dollars)	June 30, 2015	Dec. 31, 2014
Inventories		
Materials and supplies	$256,000	$244,099
Fuel	203,177	183,249
Natural gas	73,526	169,835
	$532,703	$597,183

(Thousands of Dollars)	June 30, 2015	Dec. 31, 2014
Property, plant and equipment, net		
Electric plant	$33,996,892	$33,203,139
Natural gas plant	4,726,068	4,643,452
Common and other property	1,623,828	1,611,486
Plant to be retired [a]	55,397	71,534
Construction work in progress	2,092,391	2,005,531
Total property, plant and equipment	42,494,576	41,535,142
Less accumulated depreciation	(13,543,351)	(13,168,418)
Nuclear fuel	2,405,823	2,347,422
Less accumulated amortization	(2,006,684)	(1,957,230)
	$29,350,364	$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 June 30, 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 June 30, 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 June 30, 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 June 30, 2015, there were no state income tax audits in progress.

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

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

(Millions of Dollars)	June 30, 2015	Dec. 31, 2014
Unrecognized tax benefit — Permanent tax positions	$16.4	$16.2
Unrecognized tax benefit — Temporary tax positions	56.9	50.3
Total unrecognized tax benefit	$73.3	$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)	June 30, 2015	Dec. 31, 2014
NOL and tax credit carryforwards	$(35.2)	$(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 June 30, 2015 and Dec. 31, 2014 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 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 and in Note 5 to Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

Pending and Recently Concluded 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 May 2015, the MPUC ordered a 2014 rate increase and a 2015 step increase. The total increase was estimated to be $166 million, or 5.9 percent, based on a 9.72 percent ROE and 52.50 percent equity ratio. The MPUC also approved a three-year, decoupling 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 changes in electric sales due to conservation and weather variability for these classes.

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In July 2015, the MPUC deliberated on requests for reconsideration of its order. The MPUC determined the Monticello Extended Power Uprate (EPU) project is not used-and-useful until final approval related to the full EPU uprate condition is received from the Nuclear Regulatory Commission (NRC). NSP-Minnesota expects that $13.8 million will be excluded from final rates, as approval from the NRC had not been received as of June 30, 2015. Monticello achieved the full EPU uprate level of 671 megawatts (MW) in June 2015 and received final NRC compliance approval in July 2015, thereby satisfying the used-and-useful conditions established by the MPUC. The MPUC also approved 2015 interim rates effective March 3, 2015 and stated that the 2014 interim rate refund obligation be netted against the 2015 interim rate revenue under-collections.

The MPUC's decision resulted in an estimated 2015 annual rate increase of $149.4 million or 5.3 percent. NSP-Minnesota anticipates reducing the 2014 refund obligation by approximately $6 million for the change in the interest rate applied to interim refunds and other items.

The following tables outline NSP-Minnesota's filed request and the impact of the MPUC's decisions made in May and July:

2014 Rate Request (Millions of Dollars)	NSP-Minnesota	MPUC May Decision
NSP-Minnesota's filed rate request	$ 192.7	$ 192.7
Sales forecast (with true-up to 12 months of actual weather-normalized sales)	(38.5)	(37.5)
ROE	—	(31.9)
Monticello EPU cost recovery	(12.2)	(37.6)
Property taxes (with true-up to actual 2014 accruals)	(13.2)	(13.2)
Prairie Island EPU cost recovery	(5.1)	(5.0)
Health care, pension and other benefits	(1.9)	(3.1)
Other, net	(6.5)	(5.5)
Total 2014	$ 115.3	$ 58.9

2015 Rate Request (Millions of Dollars)	NSP-Minnesota	MPUC May Decision
NSP-Minnesota's filed rate request	$ 98.5	$ 98.5
Monticello EPU cost recovery	11.7	35.4
Depreciation / Retirements	—	(0.5)
Property taxes	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)
U.S. Department of Energy (DOE) settlement proceeds	10.1	10.1
Emission chemicals	(1.6)	(1.6)
Other, net	1.7	(2.3)
Total 2015 step increase - prior to Monticello Life Cycle Management (LCM)/EPU cost disallowance	$ 106.0	$ 125.2
Total for 2014 and 2015 step increase - prior to Monticello LCM/EPU cost disallowance	$ 221.3	$ 184.1
Monticello LCM/EPU cost disallowance	—	(18.0)
Total for 2014 and 2015 step increase - including Monticello LCM/EPU cost disallowance	$ 221.3	$ 166.1

(Millions of Dollars)	MPUC July Decision
2015 annual rate increase - based on MPUC May order	$ 166.1

Reconsideration/clarification adjustments:	
2015 Monticello EPU used-and-useful adjustment	(13.8)
2014 property tax final true-up	(3.1)
Other, net	0.2
Total 2015 annual rate increase	$ 149.4
Impact of interim rate effective March 3, 2015	(3.6)
Estimated 2015 revenue impact	$ 145.8

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NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 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.

In March 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.

NSP-Minnesota – 2015 Transmission Cost Recovery (TCR) Rate Filing — In October 2014, NSP-Minnesota submitted its 2015 TCR filing with the MPUC, requesting recovery of $65.8 million of 2015 transmission investment costs not included in electric base rates. The request for 2015 was reduced to approximately $63.8 million, which was approved by the MPUC in May 2015, subject to future adjustments replacing forecasted amounts with actual investment costs. The MPUC also set rates so that NSP-Minnesota will recover its remaining 2015 and forecasted 2016 revenue requirements through the end of 2016. New rates were implemented in July 2015, subject to true-up.

Recently Concluded 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 electric rates by $15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. Interim rates of $15.6 million, subject to refund, went into effect in January 2015.

In June 2015, the SDPUC approved a settlement agreement allowing a base rate increase of approximately $6.9 million, or 3.6 percent, and providing revisions to the existing Infrastructure rider, which will recover additional net revenue of $0.9 million. Combined, the overall revenue increase in base rates and the Infrastructure rider for 2015 is approximately $7.8 million, or 4.0 percent. New rates began in July 2015. In addition, there is a moratorium on base rate increases until Jan. 1, 2018.

The settlement also includes an earnings test with a sharing mechanism. If South Dakota’s weather normalized earnings exceed a certain level, NSP-Minnesota will refund 50 percent of the excess earnings to customers.

NSP-Wisconsin

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

Wisconsin 2016 Electric and Gas Rate Case — On May 29, 2015, NSP-Wisconsin filed a request with the PSCW to increase rates for electric and natural gas service effective Jan. 1, 2016. NSP-Wisconsin requested an overall increase in annual electric rates of $27.4 million, or 3.9 percent, and an increase in natural gas rates of $5.9 million, or 5.0 percent.

The rate filing is based on a 2016 forecast test year, a return on equity of 10.2 percent, an equity ratio of 52.5 percent and a forecasted average net investment rate base of approximately $1.2 billion for the electric utility and $111.2 million for the natural gas utility.

Key dates in the procedural schedule are as follows:

- Staff and Intervenor Direct Testimony — Oct. 1, 2015;
- Rebuttal Testimony — Oct. 19, 2015;
- Sur-Rebuttal Testimony — Oct. 27, 2015;
- Technical Hearing — Oct. 29, 2015;
- Initial Brief — Nov. 12, 2015;
- Reply Brief — Nov. 19, 2015; and
- A PSCW decision is anticipated in December 2015.

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PSCo

Pending Regulatory Proceedings — Colorado Public Utilities Commission (CPUC)

PSCo – Colorado 2015 Multi-Year Gas Rate Case — In March 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 (HTY) 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 an 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 also proposed a stay-out provision, in which PSCo would not request implementation of new rates prior to January 2018, and implementation of an earnings test for 2016 through 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. 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. The following table summarizes the request:

(Millions of Dollars)	2015	2016 Step	2017 Step
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 June 2015, intervenors, including the CPUC Staff (Staff) and the Office of Consumer Counsel (OCC), filed testimony.

- Staff recommended a base rate decrease of $14.7 million, based on an ROE of 9.0 percent and a 47.04 percent equity ratio;
- OCC recommended a base rate increase of $5.8 million, based on an ROE of 9.0 percent and a 52.70 percent equity ratio;
- A multi-year plan was opposed by both the Staff and OCC;
- The Staff recommended deferring costs related to incremental property taxes and safety programs which are expected to be approximately $4.2 million in 2016 and $9.0 million in 2017; and
- The Staff opposed PSCo's proposed earnings test and the stay out provision.

Regarding the PSIA:
- The Staff proposed extending the PSIA rider for three years;
- The Staff recommended approximately $32.6 million of PSIA costs would be transferred to base rates, effective Jan. 1, 2016, in addition to the Staff's proposed 2015 base rate adjustment; and
- The OCC recommended the PSIA rider expire on June 30, 2016 and any costs be included in base rates through a step increase.

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The Staff and OCC's 2015 base rate recommendations are summarized in the following table:

(Millions of Dollars)	Staff	OCC
PSCo's filed 2015 base rate request	$40.5	$40.5
ROE	(12.8)	(13.7)
Capital structure and cost of debt	(12.8)	(4.8)
Cherokee pipeline adjustment	(11.2)	4.8
Move to 2014 historical test year	(10.5)	(16.4)
O&M expenses	(3.5)	(2.7)
Other, net	(4.4)	(1.9)
Total adjustments	$(55.2)	$(34.7)
Recommended (decrease) increase	$(14.7)	$5.8

The Staff's recommendation for the PSIA rider is as follows:

(Millions of Dollars)	2016	2017
PSCo's filed incremental PSIA request	$21.7	$21.2
Transfer PSIA O&M to base rates	(24.1)	(2.0)
ROE and capital structure	(8.2)	(3.6)
Transfer meter replacement program from base rates to PSIA	1.7	1.7
Total	$(8.9)	$17.3

On July 20, 2015, PSCo filed rebuttal testimony, maintaining its request for a multi-year plan and requested ROEs and reflecting the most recent sales forecast. PSCo also accepts portions of the Staff's position regarding the PSIA rider. PSCo's rebuttal testimony, compared to its initial filed base rate and rider request are summarized as follows:

(Millions of Dollars)	2015	2016 Step	2017 Step
PSCo's filed base rate request	$40.5	$7.6	$18.1
Shift O&M expenses between PSIA and base rates	—	7.0	6.4
Rebuttal corrections and adjustments	—	—	(7.7)
Total base rate request	$40.5	$14.6	$16.8
Incremental PSIA rider revenues	(0.1)	14.7	21.7
Total revenue impact from rebuttal	$40.4	$29.3	$38.5

If PSCo's revised request is accepted, PSIA revenue is projected to be $67.0 million in 2015, $81.7 million in 2016 and $103.4 million in 2017.

The next steps in the procedural schedule are as follows:

- Sur-Rebuttal Testimony — Aug. 3, 2015;
- Evidentiary Hearing — Aug. 18 - Aug. 31, 2015;
- Interim Rates (subject to refund) — Oct. 1, 2015; and
- Final CPUC Decision — No later than Jan. 20, 2016.

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, which was approved by the CPUC in July 2015.

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. As of June 30, 2015, PSCo has recognized management's best estimate of the expected customer refund obligation for the 2015 earnings test, based on annual forecasted information.

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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, a 2015 DSM gas budget of $13.1 million, a 2016 DSM electric budget of $78.7 million and a 2016 DSM 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. In July 2015, the administrative law judge (ALJ) approved the plan.

SPS

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

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric 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 a HTY ending June 2014, adjusted for known and measurable changes, a 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.

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.

In May 2015, several intervenors filed direct testimony in response to SPS' rate request, including the Alliance of Xcel Municipalities (AXM), the Office of Public Utility Counsel (OPUC), and the PUCT Staff (Staff).

- AXM recommended a rate decrease of $13.6 million, an ROE of 9.40 percent and an equity ratio of 53.97 percent.
- The OPUC recommended a rate increase of $1.8 million, an ROE of 9.20 percent and an equity ratio of 52.38 percent.
- The Staff recommended a rate decrease of $2.6 million, an ROE of 9.30 percent and an equity ratio of 53.97 percent.

In June 2015, SPS filed rebuttal testimony supporting a revised rate increase of approximately $42 million, or 4.4 percent.

(Millions of Dollars)	AXM	OPUC	Staff	SPS Rebuttal Testimony
SPS' revised rate request	$58.9	$58.9	$58.9	$ 58.9
Investment for capital expenditures — post-test year adjustments	(11.3)	(23.8)	(23.8)	—
Lower ROE	(10.9)	(13.5)	(12.1)	—
Rate base adjustments (largely the removal of the prepaid pension asset)	(6.2)	(6.8)	—	—
O&M expense adjustments	(13.7)	(11.0)	(7.9)	(1.6)
Depreciation expense	(13.3)	—	—	—

Property taxes	—	(1.2)	(4.4)	(1.8)
Revenue adjustments	(2.2)	(0.2)	—	—
Wholesale load reductions	(13.2)	—	(11.1)	—
Southwest Power Pool (SPP) transmission expansion plan	—	—	—	(7.3)
Other, net	(1.7)	(0.6)	(2.2)	(1.8)
Total recommendation	$(13.6)	$1.8	$(2.6)	$ 46.4
Adjustment to move rate case expenses to a separate docket	—	—	—	(4.3)
Recommendation, excluding rate case expenses	$(13.6)	$1.8	$(2.6)	$ 42.1

New rates will be made effective retroactive to June 11, 2015 as established by the PUCT. Hearings were completed in July 2015. A PUCT decision is expected in the fourth quarter of 2015.

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

SPS – New Mexico 2015 Electric Rate Case — In June 2015, SPS filed an electric rate case with the NMPRC for an increase in non-fuel base rates of $31.5 million and a base fuel decrease of $30.1 million. The rate filing was based on a 2016 forecast test year (FTY), a requested return on equity of 10.25 percent, a jurisdictional electric rate base of $777.9 million and an equity ratio of 53.97 percent.

In June 2015, SPS' rate case application was dismissed by the NMPRC. The NMPRC determined that the filing did not comply with its new interpretation of the statute regarding FTY periods and the corresponding timing of a rate case submission in relation to the FTY used in the case. This new interpretation occurred during the recent Public Service Company of New Mexico rate case.

In July, SPS filed an appeal with the New Mexico Supreme Court. In addition, SPS plans to file a rate case later this year.

Pending and Recently Concluded 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 adopting a new ROE methodology, which requires electric utilities to use a two-step discounted cash flow analysis that incorporates both short-term and long-term growth projections to estimate the cost of equity.

The FERC 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. In January 2015, the ROE complaint was set for full hearing procedures.

The complainants and intervenors filed testimony recommending an ROE between 8.67 percent and 9.54 percent. The FERC staff recommended an ROE of 8.68 percent. The MISO TOs recommended an ROE not less than 10.8 percent. A hearing is scheduled for August 2015, with an ALJ initial decision to be issued by November 2015 and a FERC order issued no earlier than 2016.

In November 2014, certain 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 February 2015, an intervenor in the November 2013 ROE complaint filed a second complaint proposing to reduce the MISO region ROE to 8.67 percent, prior to any 50 basis point RTO adder. In June 2015, the FERC set the second ROE complaint for a hearing process, establishing a Feb. 12, 2015 refund effective date. An ALJ initial decision is expected in June 2016 with a FERC decision in late 2016 or in 2017. The FERC decision would continue the ROE refund obligation initiated under the November 2013 complaint through May 2016. On July 20, 2015, the MISO TOs sought rehearing of the FERC decision to allow back-to-back complaints involving the same issue with consecutive refund periods, arguing this ruling is contrary to the governing statute. FERC action on the rehearing request is pending.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE as of June 30, 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.

SPS – Wholesale Rate ROE 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, and asking that the ROEs be reduced to 9.15 percent and 9.65 percent, respectively, effective April 20, 2012. In July 2013, Golden Spread filed a second complaint, again asking that the ROE in the SPS production formula rate for Golden Spread and transmission formula rates be reduced to 9.15 and 9.65 percent, respectively, effective July 19, 2013. In June 2014, the FERC issued orders consolidating the Golden Spread ROE complaints and setting the complaints for settlement judge or hearing procedures.

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A third rate complaint was filed in October 2014 by Golden Spread, certain New Mexico cooperatives and the West Texas Municipal Power Agency, requesting that the ROE in certain SPS production formula rates for Golden Spread and the New Mexico cooperatives and transmission formula rates be reduced, this time to 8.61 percent and 9.11 percent, respectively, effective 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. The FERC established effective dates for refunds of April 20, 2012 (first refund period), July 19, 2013 (second refund period) and Oct. 20, 2014 (third refund period), respectively.

SPS sought rehearing of the FERC decisions to allow back-to-back complaints involving the same issue with consecutive 15 month refund periods, asserting this ruling is contrary to the governing statute. On May 12, 2015, FERC denied the rehearing request as it pertained to the first two rate complaints. In July 2015, SPS filed an appeal to the D.C. Circuit Court of Appeals of the FERC orders in the first two rate complaints allowing the sequential complaints and consecutive 15 month refund periods. The D.C. Circuit Court has not established a procedural schedule. FERC action on the similar SPS rehearing request related to the third complaint is pending.

In the first half 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 [b]	1	8.78 %	9.28 %
	2	8.51	9.01
	3	8.45	8.95
SPS	1	10.25	10.39
	2	10.25	11.20
	3 [c]	10.40	11.20
FERC Staff	1	8.97	9.47
	2	8.64	9.14
	3	8.53	9.03

(a) Includes a SPP RTO membership adder up to 50 basis points.
(b) For the third refund period, the recommended production and transmission ROEs are supported by Golden Spread, certain New Mexico cooperatives and the West Texas Municipal Power Agency (transmission ROE only).
(c) In addition to the recommended ROEs, SPS also filed testimony recommending the ROEs remain unchanged.

Hearings scheduled for July 2015 for the first two rate complaints were canceled and the parties agreed to file briefs based on pre-filed testimony. An initial ALJ decision on the first two complaints is expected to be issued by Nov. 25, 2015, and a final FERC order to be issued no earlier than 2016. A hearing for the third rate complaint is scheduled for Oct. 2015, with an ALJ initial decision expected in January 2016 and a final FERC order no earlier than later in 2016.

SPS recorded a current liability representing the current best estimate of a refund obligation associated with potential ROE adjustments as of June 30, 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 12 CP system.

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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 $1.5 million of principal and interest has been accrued during 2015.

SPS – 2015 Production Formula Rate Change Filing — In January 2015, SPS filed to revise the production formula rates for six of its wholesale customers, including Golden Spread, certain New Mexico cooperatives and West Texas Municipal Power Agency, 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. In March 2015, the FERC accepted this filing, effective July 1, 2015, subject to refund and settlement judge or hearing procedures. The parties remain engaged in settlement judge procedures. Effective June 1, 2015, the Golden Spread contract demand quantity subject to the formula rate change declined from 500 MW to 300 MW.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5 above, the circumstances set forth in Notes 5, 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 and in Notes 5 and 6 to the consolidated financial statements included in Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015, 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 June 30, 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 June 30, 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)	June 30, 2015	Dec. 31, 2014
Guarantees issued and outstanding	$ 13.2	$ 13.9
Current exposure under these guarantees	0.1	0.2
Bonds with indemnity protection	41.9	31.4

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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).

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 preliminary activities, including the installation of ground wells, have commenced at the site. Construction on the groundwater treatment plant is anticipated to commence in fall 2015. The current cost estimate for the cleanup of the Phase I Project Area is approximately $57 million, of which approximately $35 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.

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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 took place in May 2015. A judicial decision is expected in the third quarter of 2015. 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 contributed $10.5 million and LE Myers Co. contributed $5.4 million to the costs of the cleanup at the Ashland site. The agreements for the Railroad PRPs and LE Myers Co. were approved by the U.S. District Court for the Western District of Wisconsin in 2015 and payment has been received. As discussed below, existing PSCW policy requires that any payments received from PRPs be used to reduce the amount of the cleanup costs ultimately recovered from customers. Two additional PRPs remain in the case.

At June 30, 2015 and Dec. 31, 2014, NSP-Wisconsin had recorded a liability of $108.5 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 $23.2 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, 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 December 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. In May 2015, NSP-Wisconsin filed its 2016 rate case, in which it requested an increase to the annual recovery for MGP clean-up costs from $4.7 million to $7.6 million. A decision is anticipated in late 2015.

Fargo, N.D. MGP Site — In May 2015, in connection with a city water main replacement and street improvement project in Fargo, N.D., underground pipes, tars, and impacted soils, which may be related to a former MGP site operated by NSP-Minnesota or a prior company, were discovered. After initial reports and discussions with the City of

Fargo and the North Dakota Department of Health, NSP-Minnesota removed the impacted soils and other materials from the project area. At this time, NSP-Minnesota's investigation of the site is considered preliminary as information is still being gathered.

As of June 30, 2015, NSP-Minnesota recorded a liability of $2.1 million related to further investigation and additional planned activities. Uncertainties include the nature and cost of the additional remediation efforts that may be necessary, the ability to recover costs from insurance carriers and the potential for contributions from entities that may be identified as PRPs. Therefore, the total cost of remediation, NSP-Minnesota's potential liability and amounts allocable to the North Dakota and Minnesota jurisdictions related to the site cannot currently be reasonably estimated. In July 2015, NSP-Minnesota filed a request with the North Dakota Public Service Commission (NDPSC) for approval to initially defer the portion of investigation and response costs allocable to the North Dakota jurisdiction.

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Environmental Requirements

Water

Federal Clean Water Act (CWA) Waters of the United States Rule — In June 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly expands the types of water bodies regulated under the CWA and broadens the scope of waters subject to federal jurisdiction. The expansion of the term “Waters of the U.S.” will subject more utility projects to federal CWA jurisdiction, thereby potentially delaying the siting of new generation projects, pipelines, transmission lines and distribution lines, as well as increasing project costs and expanding permitting and reporting requirements. The rule will go into effect beginning in August 2015. Xcel Energy does not anticipate the costs of compliance with the final rule will have a material impact on the results of operations, financial position or cash flows.

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 Clean Air Interstate Rule (CAIR) pending adoption of a valid replacement. In April 2014, the U.S. Supreme Court reversed and remanded the case to the D.C. Circuit. The 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 were considered on remand. In July 2015, the D.C. Circuit issued an opinion which found the reduction budgets exceed what is necessary for Texas to reduce its impact on downwind states that do not meet ambient air quality standards. The D.C. Circuit remanded the matter to the EPA to reconsider the emission budgets. While the EPA reconsiders emission budgets, the D.C. Circuit left CSAPR in effect.

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 is administering 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 or less.

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 is complying with the CSAPR for NOx in 2015 through operational changes or allowance purchases. CSAPR compliance in 2015 is not having a material impact on the results of operations, financial position or cash flows.

Electric Generating Unit (EGU) Mercury and Air Toxics Standards (MATS) Rule — The final EGU MATS rule became effective in April 2012. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and requires coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years of the effective date. In 2014, the U.S. Supreme Court decided to review the D.C. Circuit’s decision that upheld the MATS standard. By April 2015, the MATS compliance deadline, Xcel Energy had met the EGU MATS rule through a combination of emission control projects and controls required by other programs preceding MATS, such as regional haze and state mercury regulations. Xcel Energy also retired two coal units at the Black Dog plant and ceased use of coal at Bay Front Unit 5. In addition, mercury controls were installed in SPS' Tolk and Harrington plants for a capital cost of $8 million. On June 29, 2015, the U.S. Supreme Court found that the EPA acted unreasonably by not considering the cost to regulate mercury and other hazardous air pollutants. The D.C. Circuit, on remand, will decide whether to leave MATS in effect while the EPA considers such costs in making a new determination. Xcel Energy believes EGU MATS costs will be recoverable through regulatory mechanisms and does not anticipate a material impact on the results of operations, financial position or cash flows.

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.

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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 10th 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 May 2015, the EPA published its final rule which re-affirmed the approval of the State of Colorado's BART determination for Comanche Units 1 and 2. The determination found that the controls currently installed on the units for NOx are BART. In July 2015, WildEarth Guardians filed a petition for review of the EPA's May 2015 final rule. The 10th Circuit will now resume litigation and a decision is anticipated in 2016.

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.

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 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. 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 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 December 2015.

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. The EPA proposed to require dry scrubbers on both Tolk units to reduce SO_2 emissions to help achieve reasonable progress goals 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 December 2015. 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. Xcel Energy believes these costs would be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

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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 determine whether there is RAVI-type impairment in these parks and identify the potential source of the impairment. 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 (Minnesota District Court) 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 May 2015, NSP-Minnesota, the EPA and the six environmental advocacy organizations filed a settlement agreement in the Minnesota District Court. The agreement anticipates a federal rulemaking that would impose stricter SO_2 emission limits on Sherco Units 1, 2 and 3, without making a RAVI attribution finding or a RAVI BART determination. The emission limits for Units 1 and 2 reflect the success of a recently completed control project. The Unit 3 emission limits will be met through changes in the operation of the existing scrubber. The Minnesota District Court issued an order staying the litigation for the time needed to complete the actions required by the settlement agreement. The plaintiffs agreed to withdraw their complaint with prejudice when those actions are completed. Plaintiffs also agreed not to request a RAVI certification for Sherco Units 1, 2 and/or 3 in the future.

As required by the CAA, the EPA published notice of the proposed settlement in the Federal Register. The EPA reviewed the public comments in July 2015 and notified the Minnesota District Court that the settlement agreement is final. The EPA has seven months to recommend and adopt a rule which will set the agreed-upon SO_2 emissions. Xcel Energy does not anticipate the costs of compliance with the proposed settlement will have a material impact on the results of operations, financial position or cash flows.

Implementation of the National Ambient Air Quality Standard (NAAQS) for SO_2 — The EPA adopted a more stringent NAAQS for SO_2 in 2010. In 2013, the EPA designated areas as not attaining the revised NAAQS, which did not include any areas where Xcel Energy operates power plants. However, many other areas of the country were unable to be classified by the EPA due to a lack of air monitors.

Following a lawsuit alleging that the EPA had not completed its area designations in the time required by the CAA and under a consent decree the EPA is requiring states to evaluate areas in three phases. The first phase includes areas near PSCo's Pawnee plant and SPS' Tolk and Harrington plants. The Pawnee plant recently installed an SO_2 scrubber and the Tolk and Harrington Plants utilize low sulfur coal to reduce SO_2 emissions. The Colorado Department of Health and Environment along with the Texas Commission on Environmental Quality (TCEQ) are expected to make recommendations for nonattainment areas to the EPA in September 2015 with a decision by summer 2016.

If an area is designated nonattainment, the respective states will need to evaluate all SO_2 sources in the area. The state would then submit an implementation plan for the respective areas which would be due in 18 months, designed to achieve the NAAQS within five years. The TCEQ could require additional SO_2 controls on one or more of the units at

Tolk and Harrington. It is anticipated the areas near the remaining Xcel Energy power plants would be evaluated in the next designation phase, ending December 2017. Xcel Energy cannot evaluate the impacts of this ruling until the designation of nonattainment areas is made and any required state plans are developed. Xcel Energy believes that, should SO_2 control systems be required for a plant, compliance costs will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

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Legal Contingencies

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

Employment, Tort and Commercial Litigation

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.

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.

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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, including PSCo jointly with others, submitted briefs on May 8, 2015. Oral argument was held on June 16, 2015, and the matter is now pending before the Ninth Circuit.

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 contracts 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 spent 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 June 30, 2015. On May 15, 2015, NSP-Minnesota submitted a claim for an additional $13.4 million. 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.

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

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2015		Twelve Months Ended Dec. 31, 2014	
Borrowing limit	$2,750		$2,750	
Amount outstanding at period end	451		1,020	
Average amount outstanding	780		841	
Maximum amount outstanding	1,072		1,200	
Weighted average interest rate, computed on a daily basis	0.48	%	0.33	%
Weighted average interest rate at period end	0.48		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 June 30, 2015 and Dec. 31, 2014, there were $67.8 million and $60.5 million, respectively, 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 June 30, 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	$72	$928
PSCo	700	58	642
NSP-Minnesota	500	144	356
SPS	400	245	155
NSP-Wisconsin	150	—	150
Total	$2,750	$519	$2,231

(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 June 30, 2015 and Dec. 31, 2014.

Long-Term Borrowings

During the six months ended June 30, 2015, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In May, PSCo issued $250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- In June, Xcel Energy Inc. issued $250 million of 1.2 percent senior notes due June 1, 2017 and $250 million of 3.3 percent senior notes due June 1, 2025; and
- In June, NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024.

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8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

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

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

Specific valuation methods include the following:

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

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

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

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

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

Electric commodity derivatives held by NSP-Minnesota 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.

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

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and Prairie Island (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 $335.3 million and $312.1 million at June 30, 2015 and Dec. 31, 2014, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $31.4 million and $74.1 million at June 30, 2015 and Dec. 31, 2014, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at June 30, 2015 and Dec. 31, 2014:

	June 30, 2015				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$12,446	$12,446	$—	$—	$12,446
Commingled funds	451,398	—	499,782	—	499,782
International equity funds	123,123	—	121,502	—	121,502
Private equity investments	95,067	—	—	133,993	133,993
Real estate	49,369	—	—	70,834	70,834
Debt securities:					
Government securities	24,408	—	22,183	—	22,183
U.S. corporate bonds	69,194	—	66,096	—	66,096
International corporate bonds	16,506	—	16,294	—	16,294
Municipal bonds	209,103	—	210,898	—	210,898
Asset-backed securities	2,831	—	2,851	—	2,851

Mortgage-backed securities	12,039	—	12,219	—	12,219
Equity securities:					
Common stock	382,755	583,031	—	—	583,031
Total	$1,448,239	$595,477	$951,825	$204,827	$1,752,129

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $81.0 million of equity investments in unconsolidated subsidiaries and $47.0 million of miscellaneous investments.

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	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.

The following tables present the changes in Level 3 nuclear decommissioning fund investments for the three and six months ended June 30, 2015 and 2014:

(Thousands of Dollars)	April 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	June 30, 2015
Private equity investments	$113,619	$8,749	$—	$11,625	$133,993
Real estate	67,774	4,271	(1,241)	30	70,834
Total	$181,393	$13,020	$(1,241)	$11,655	$204,827

(Thousands of Dollars)	April 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Asset [(a)]	June 30, 2014
Private equity investments	$73,801	$2,184	$—	$5,138	$81,123
Real estate	62,954	197	—	2,507	65,658
Total	$136,755	$2,381	$—	$7,645	$146,781

(Thousands of Dollars)	Jan. 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets [(a)]	June 30, 2015
Private equity investments	$101,237	$21,131	$—	$11,625	$133,993

Real estate	64,249	8,132	(2,622)	1,075	70,834
Total	$165,486	$29,263	$(2,622)	$12,700	$204,827

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Asset [(a)]	June 30, 2014
Private equity investments	$62,696	$10,953	$—	$7,474	$81,123
Real estate	57,368	3,856	—	4,434	65,658
Total	$120,064	$14,809	$—	$11,908	$146,781

(a) Gains are deferred as a component of the regulatory assets for nuclear decommissioning.

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The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at June 30, 2015:

(Thousands of Dollars)	Final Contractual Maturity Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$—	$—	$22,183	$22,183
U.S. corporate bonds	—	14,684	54,005	(2,593)	66,096
International corporate bonds	—	3,951	11,325	1,018	16,294
Municipal bonds	361	32,427	41,313	136,797	210,898
Asset-backed securities	—	—	2,851	—	2,851
Mortgage-backed securities	—	—	—	12,219	12,219
Debt securities	$361	$51,062	$109,494	$169,624	$330,541

Derivative Instruments Fair Value Measurements

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

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

At June 30, 2015, accumulated other comprehensive losses related to interest rate derivatives included $3.4 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.

At June 30, 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 and six months ended June 30, 2015 and 2014.

At June 30, 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.

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The following table details the gross notional amounts of commodity forwards, options and FTRs at June 30, 2015 and Dec. 31, 2014:

(Amounts in Thousands) [a][b]	June 30, 2015	Dec. 31, 2014
Megawatt hours of electricity	97,459	56,361
Million British thermal units of natural gas	7,959	927
Gallons of vehicle fuel	211	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 and six months ended June 30, 2015 and 2014, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended June 30, 2015				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains 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	$—	$—	$954 (a)	$—	$—
Vehicle fuel and other commodity	29	—	28 (b)	—	—
Total	$29	$—	$982	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$4,401 (c)
Electric commodity	—	(4,737)	—	(8,037) (d)	—
Natural gas commodity	—	(232)	—	(22) (e)	—
Total	$—	$(4,969)	$—	$(8,059)	$4,401

	Six Months Ended June 30, 2015				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$1,894 (a)	$—	$—
Vehicle fuel and other commodity	11	—	55 (b)	—	—
Total	$11	$—	$1,949	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$8,281 (c)

Electric commodity	—	(14,208)	—	(13,160) [d]	—
Natural gas commodity	—	(448)	—	(8,852) [e]	8,991 [e]
Total	$—	$(14,656)	$—	$(22,012)	$17,272

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(Thousands of Dollars)	Three Months Ended June 30, 2014 Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$956 (a)	$—	$—
Vehicle fuel and other commodity	25	—	(17) (b)	—	—
Total	$25	$—	$939	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$5,176 (c)
Electric commodity	—	(17,375)	—	(4,574) (d)	—
Natural gas commodity	—	(2,449)	—	—	(65) (d)
Other commodity	—	—	—	—	643 (c)
Total	$—	$(19,824)	$—	$(4,574)	$5,754

(Thousands of Dollars)	Six Months Ended June 30, 2014 Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$1,902 (a)	$—	$—
Vehicle fuel and other commodity	14	—	(45) (b)	—	—
Total	$14	$—	$1,857	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$2,922 (c)
Electric commodity	—	(13,849)	—	(25,270) (d)	—
Natural gas commodity	—	16,058	—	(18,840) (e)	(5,367) (e)
Other commodity	—	—	—	—	643 (c)
Total	$—	$2,209	$—	$(44,110)	$(1,802)

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

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

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

(e) Amounts for the three and six months ended June 30, 2015 and six months ended 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 and six months ended June 30, 2015 and six months ended 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 and six months ended June 30, 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.

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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 June 30, 2015, four of Xcel Energy’s 10 most significant counterparties for these activities, comprising $44.6 million or 18 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 six significant counterparties, comprising $71.5 million or 28 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 June 30, 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.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary’s ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of June 30, 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 June 30, 2015:

	June 30, 2015					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$—	$11,596	$7,927	$19,523	$(6,849)	$12,674
Electric commodity	—	—	51,355	51,355	(10,600)	40,755
Natural gas commodity	—	253	—	253	(166)	87
Total current derivative assets	$—	$11,849	$59,282	$71,131	$(17,615)	53,516
PPAs [a]						10,087
Current derivative instruments						$63,603
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$23,771	$—	$23,771	$(5,503)	$18,268
Total noncurrent derivative assets	$—	$23,771	$—	$23,771	$(5,503)	18,268
PPAs [a]						35,038
Noncurrent derivative instruments						$53,306

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(Thousands of Dollars)	June 30, 2015 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	$—	$106	$—	$106	$—	$106
Other derivative instruments:						
Commodity trading	—	8,338	1,855	10,193	(7,097)	3,096
Electric commodity	—	—	10,600	10,600	(10,600)	—
Natural gas commodity	—	490	—	490	(166)	324
Other commodity	—	450	—	450	—	450
Total current derivative liabilities	$—	$9,384	$12,455	$21,839	$(17,863)	3,976
PPAs [a]						22,869
Current derivative instruments						$26,845
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$49	$—	$49	$—	$49
Other derivative instruments:						
Commodity trading	—	13,853	—	13,853	(11,731)	2,122
Other commodity	—	26	—	26	—	26
Total noncurrent derivative liabilities	$—	$13,928	$—	$13,928	$(11,731)	2,197
PPAs [a]						169,494
Noncurrent derivative instruments						$171,691

(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 June 30, 2015. At June 30, 2015, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $6.5 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

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(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.

The following table presents the changes in Level 3 commodity derivatives for the three and six months ended June 30, 2015 and 2014:

(Thousands of Dollars)	Three Months Ended June 30 2015	2014
Balance at April 1	$17,429	$24,217
Purchases	57,446	120,107
Settlements	(17,315)	(33,610)
Net transactions recorded during the period:		

Gains recognized in earnings [a]	1,220	6,438
(Losses) recognized as regulatory assets and liabilities	(11,953)	(11,758)
Balance at June 30	$46,827	$105,394

	Six Months Ended June 30	
(Thousands of Dollars)	2015	2014
Balance at Jan. 1	$56,155	$41,660
Purchases	63,238	121,164
Settlements	(37,246)	(87,419)
Net transactions recorded during the period:		
Gains recognized in earnings [a]	1,280	7,437
(Losses) gains recognized as regulatory assets and liabilities	(36,600)	22,552
Balance at June 30	$46,827	$105,394

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

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Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and six months ended June 30, 2015 and 2014.

Fair Value of Long-Term Debt

As of June 30, 2015 and Dec. 31, 2014, other financial instruments for which the carrying amount did not equal fair value were as follows:

	June 30, 2015		Dec. 31, 2014	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$12,603,482	$13,585,712	$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 June 30, 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 June 30		Six Months Ended June 30	
(Thousands of Dollars)	2015	2014	2015	2014
Interest income	$389	$1,292	$4,627	$5,185
Other nonoperating income	794	1,293	1,762	2,396
Insurance policy expense	(222)	(2,438)	(2,267)	(4,246)
Other nonoperating expense	—	(65)	—	(52)
Other income, net	$961	$82	$4,122	$3,283

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.
-

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 $81.0 million and $83.1 million as of June 30, 2015 and Dec. 31, 2014, respectively, included in the regulated natural gas utility segment.

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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 operating and maintenance (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 June 30, 2015					
Operating revenues from external customers	$2,213,460	$284,131	$17,543	$—	$2,515,134
Intersegment revenues	420	172	—	(592)	—
Total revenues	$2,213,880	$284,303	$17,543	$(592)	$2,515,134
Net income (loss)	$214,955	$(6,883)	$(11,141)	$—	$196,931

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2014					
Operating revenues from external customers	$2,297,638	$369,127	$18,331	$—	$2,685,096
Intersegment revenues	437	1,118	—	(1,555)	—
Total revenues	$2,298,075	$370,245	$18,331	$(1,555)	$2,685,096
Net income (loss)	$185,677	$15,297	$(5,810)	$—	$195,164

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2015					
Operating revenues from external customers	$4,438,323	$1,000,127	$38,903	$—	$5,477,353
Intersegment revenues	750	848	—	(1,598)	—
Total revenues	$4,439,073	$1,000,975	$38,903	$(1,598)	$5,477,353
Net income (loss)	$295,976 [a]	$76,793	$(23,772)	$—	$348,997

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2014					
Operating revenues from external customers	$4,599,348	$1,248,815	$39,537	$—	$5,887,700
Intersegment revenues	790	4,370	—	(5,160)	—
Total revenues	$4,600,138	$1,253,185	$39,537	$(5,160)	$5,887,700
Net income (loss)	$371,110	$92,633	$(7,358)	$—	$456,385

[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.

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Stock equivalent units granted to Xcel Energy Inc.’s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due to certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted.

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

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

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

	Three Months Ended June 30, 2015			Three Months Ended June 30, 2014		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$196,931	—	—	$195,164	—	—
Basic EPS:						
Earnings available to common shareholders	196,931	507,707	$0.39	195,164	503,272	$0.39
Effect of dilutive securities:						
Time based equity awards	—	367	—	—	184	—
Diluted EPS:						
Earnings available to common shareholders	$196,931	508,074	$0.39	$195,164	503,456	$0.39

	Six Months Ended June 30, 2015			Six Months Ended June 30, 2014		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$348,997	—	—	$456,385	—	—
Basic EPS:						
Earnings available to common shareholders	348,997	507,359	$0.69	456,385	501,408	$0.91
Effect of dilutive securities:						
Time based equity awards	—	388	—	—	204	—
Diluted EPS:						
Earnings available to common shareholders	$348,997	507,747	$0.69	$456,385	501,612	$0.91

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2015	2014	2015	2014
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$24,828	$22,085	$529	$864
Interest cost	37,131	39,155	6,324	8,507
Expected return on plan assets	(53,472)	(51,801)	(6,650)	(8,488)
Amortization of prior service credit	(451)	(436)	(2,671)	(2,672)
Amortization of net loss	31,288	29,190	1,351	2,935

Net periodic benefit cost (credit)	39,324	38,193	(1,117)	1,146
Costs not recognized due to the effects of regulation	(7,523)	(6,604)	—	—
Net benefit cost (credit) recognized for financial reporting	$31,801	$31,589	$(1,117)	$1,146

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(Thousands of Dollars)	Six Months Ended June 30 2015 Pension Benefits	2014 Pension Benefits	2015 Postretirement Health Care Benefits	2014 Postretirement Health Care Benefits
Service cost	$49,656	$44,171	$1,058	$1,728
Interest cost	74,262	78,310	12,648	17,014
Expected return on plan assets	(106,945)	(103,602)	(13,300)	(16,977)
Amortization of prior service credit	(902)	(873)	(5,343)	(5,344)
Amortization of net loss	62,576	58,381	2,702	5,870
Net periodic benefit cost (credit)	78,647	76,387	(2,235)	2,291
Costs not recognized due to the effects of regulation	(15,019)	(13,656)	—	—
Net benefit cost (credit) recognized for financial reporting	$63,628	$62,731	$(2,235)	$2,291

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 and six months ended June 30, 2015 and 2014 were as follows:

(Thousands of Dollars)	Three Months Ended June 30, 2015 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 April 1	$(57,054)	$111	$(49,745)	$(106,688)
Other comprehensive income before reclassifications	18	1	—	19
Losses reclassified from net accumulated other comprehensive loss	600	—	883	1,483
Net current period other comprehensive income	618	1	883	1,502
Accumulated other comprehensive (loss) income at June 30	$(56,436)	$112	$(48,862)	$(105,186)

(Thousands of Dollars)	Three Months Ended June 30, 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 April 1	$(59,200)	$115	$(45,735)	$(104,820)
Other comprehensive income before reclassifications	16	—	—	16
Losses reclassified from net accumulated other comprehensive loss	574	—	864	1,438
Net current period other comprehensive income	590	—	864	1,454
Accumulated other comprehensive (loss) income at June 30	$(58,610)	$115	$(44,871)	$(103,366)

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	Six Months Ended June 30, 2015			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$(57,628)	$110	$(50,621)	$(108,139)
Other comprehensive income before reclassifications	7	2	—	9
Losses reclassified from net accumulated other comprehensive loss	1,185	—	1,759	2,944
Net current period other comprehensive income	1,192	2	1,759	2,953
Accumulated other comprehensive (loss) income at June 30	$(56,436)	$112	$(48,862)	$(105,186)

	Six Months Ended June 30, 2014			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$(59,753)	$77	$(46,599)	$(106,275)
Other comprehensive income before reclassifications	8	38	—	46
Losses reclassified from net accumulated other comprehensive loss	1,135	—	1,728	2,863
Net current period other comprehensive income	1,143	38	1,728	2,909
Accumulated other comprehensive (loss) income at June 30	$(58,610)	$115	$(44,871)	$(103,366)

Reclassifications from accumulated other comprehensive loss for the three and six months ended June 30, 2015 and 2014 were as follows:

	Amounts Reclassified from Accumulated Other Comprehensive Loss	
(Thousands of Dollars)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014
(Gains) losses on cash flow hedges:		
Interest rate derivatives	$954 (a)	$956 (a)
Vehicle fuel derivatives	28 (b)	(17) (b)
Total, pre-tax	982	939
Tax benefit	(382)	(365)
Total, net of tax	600	574
Defined benefit pension and postretirement (gains) losses:		
Amortization of net loss	1,533 (c)	1,500 (c)
Prior service credit	(89) (c)	(86) (c)
Total, pre-tax	1,444	1,414
Tax benefit	(561)	(550)

Total, net of tax	883	864
Total amounts reclassified, net of tax	$1,483	$1,438

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(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Six Months Ended June 30, 2015		Six Months Ended June 30, 2014	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$1,894	(a)	$1,902	(a)
Vehicle fuel derivatives	55	(b)	(45	) (b)
Total, pre-tax	1,949		1,857	
Tax benefit	(764	)	(722	)
Total, net of tax	1,185		1,135	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	3,068	(c)	2,999	(c)
Prior service (credit) cost	(179	) (c)	(172	) (c)
Total, pre-tax	2,889		2,827	
Tax benefit	(1,130	)	(1,099	)
Total, net of tax	1,759		1,728	
Total amounts reclassified, net of tax	$2,944		$2,863	

(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 unaudited consolidated financial statements and the related notes to consolidated financial statements. Due to the seasonality of Xcel Energy’s operating results, quarterly financial results are not an appropriate base from which to project annual results.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 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 slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; 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 Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended June 30, 2015.

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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 June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	2015	2014	2015	2014
PSCo	$0.19	$0.18	$0.41	$0.41
NSP-Minnesota	0.15	0.15	0.32	0.37
SPS	0.05	0.06	0.08	0.09
NSP-Wisconsin	0.02	0.02	0.07	0.07
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility	0.42	0.42	0.90	0.96
Xcel Energy Inc. and other	(0.03)	(0.03)	(0.05)	(0.05)
Ongoing diluted EPS	0.39	0.39	0.85	0.91
Loss on Monticello LCM/EPU project	—	—	(0.16)	—
GAAP diluted EPS	$0.39	$0.39	$0.69	$0.91

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.

For the six months ended June 30, 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 — Xcel Energy’s ongoing earnings were flat for the second quarter of 2015 and decreased $0.06 per share year-to-date, which excludes an adjustment for a charge related to the Monticello LCM/EPU project. Electric margin increased due to new rates and riders in various jurisdictions and a lower PSCo earnings test refund that was partially offset by weather-normalized sales decline and unfavorable weather. This increase was offset by higher depreciation, lower allowance for funds used during construction, higher property taxes, operating and maintenance expenses and interest charges.

PSCo — PSCo’s ongoing earnings increased $0.01 per share for the second quarter of 2015 and were flat year-to-date. The positive impact of implementing the CACJA rider, effective in January 2015, and lower estimated electric earnings test refunds were offset by lower AFUDC, higher property taxes, depreciation, and O&M expenses, as well as the impact of weather and weather-normalized sales decline.

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NSP-Minnesota — NSP-Minnesota's ongoing earnings were flat for the second quarter of 2015 and decreased $0.05 per share year-to-date. Higher revenue attributable to electric rate cases in Minnesota, North Dakota and South Dakota were more than offset by increases in depreciation, O&M expenses, property taxes and interest charges, as well as unfavorable weather and weather-normalized sales decline.

SPS — SPS' ongoing earnings decreased $0.01 per share for the second quarter of 2015 and year-to-date. Higher electric rates in Texas were offset by higher O&M expenses, depreciation, and lower AFUDC, along with the impact of unfavorable weather.

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

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2015 EPS compared with the same period in 2014:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
2014 GAAP and ongoing diluted EPS	$0.39	$0.91
Components of change — 2015 vs. 2014		
Higher electric margins	0.06	0.11
Lower conservation and DSM program expenses (offset by lower revenues)	0.02	0.05
Higher depreciation and amortization	(0.02)	(0.06)
Higher O&M expenses	(0.01)	(0.04)
Lower AFUDC — equity	(0.02)	(0.04)
Higher taxes (other than income taxes)	(0.02)	(0.03)
Higher ETR	(0.01)	(0.03)
Lower natural gas margins	—	(0.02)
Higher interest charges	(0.01)	(0.01)
Other, net	0.01	0.01
2015 ongoing diluted EPS	0.39	0.85
Loss on Monticello LCM/EPU project	—	(0.16)
2015 GAAP diluted EPS	$0.39	$0.69

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2015	2014	2015	2014
GAAP income (loss) by segment				
Regulated electric income	$215.0	$185.7	$296.0	$371.1
Regulated natural gas income	(6.9)	15.3	76.8	92.6
Other (loss) income [(a)]	4.5	8.7	2.3	20.1
Xcel Energy Inc. and other [(a)]	(15.7)	(14.5)	(26.1)	(27.4)
Total net income	$196.9	$195.2	$349.0	$456.4

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Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended June 30 2015	2014	Six Months Ended June 30 2015	2014
GAAP earnings (loss) by segment				
Regulated electric	$0.42	$0.37	$0.58	$0.74
Regulated natural gas	(0.01)	0.03	0.15	0.18
Other [(a)]	0.01	0.02	0.01	0.04
Xcel Energy Inc. and other [(a)]	(0.03)	(0.03)	(0.05)	(0.05)
Total diluted EPS	$0.39	$0.39	$0.69	$0.91

[(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.

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.

The percentage decrease in normal and actual HDD, CDD and THI is provided in the following table:

	Three Months Ended June 30 2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	Six Months Ended June 30 2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
HDD	(8.1)%	4.5 %	(12.4)%	(2.4)%	12.3 %	(13.2)%
CDD	(19.1)	0.6	(16.8)	(19.2)	1.0	(17.4)
THI	(20.8)	9.3	(25.1)	(21.0)	8.4	(25.2)

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

	Three Months Ended June 30			Six Months Ended June 30		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
Retail electric	$(0.013)	$0.002	$(0.015)	$(0.013)	$0.034	$(0.047)
Firm natural gas	(0.001)	0.001	(0.002)	(0.005)	0.019	(0.024)
Total	$(0.014)	$0.003	$(0.017)	$(0.018)	$0.053	$(0.071)

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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 June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Actual					
Electric residential [(a)]	(4.2)%	0.5%	(6.4)%	(11.4)%	(5.7)%
Electric commercial and industrial	(1.3)	(1.7)	(0.2)	0.5	(2.9)
Total retail electric sales	(2.1)	(1.1)	(2.0)	(2.8)	(3.6)
Firm natural gas sales	(16.7)	(8.0)	(31.6)	(26.0)	N/A

	Three Months Ended June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Weather-normalized					
Electric residential [(a)]	(2.3)%	(1.2)%	(3.0)%	(6.3)%	(0.5)%
Electric commercial and industrial	(0.7)	(2.3)	0.4	1.4	(1.3)
Total retail electric sales	(1.2)	(1.9)	(0.6)	(0.7)	(1.3)
Firm natural gas sales	(14.9)	(13.7)	(17.4)	(16.6)	N/A

	Six Months Ended June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Actual					
Electric residential [(a)]	(4.6)%	(1.5)%	(6.3)%	(9.2)%	(4.2)%
Electric commercial and industrial	(0.6)	(0.7)	(0.9)	1.0	(0.6)
Total retail electric sales	(1.8)	(0.9)	(2.6)	(2.2)	(1.4)
Firm natural gas sales	(11.8)	(9.1)	(15.9)	(13.5)	N/A

	Six Months Ended June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Weather-normalized					
Electric residential [(a)]	(1.3)%	(1.1)%	(1.8)%	(3.4)%	0.8%
Electric commercial and industrial	0.1	(0.6)	—	2.3	0.3
Total retail electric sales	(0.4)	(0.8)	(0.5)	0.6	0.3
Firm natural gas sales	(2.0)	(2.5)	(1.4)	—	N/A

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

Weather-normalized Electric Year-to-Date 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. This was partially offset by the impact of wet weather which resulted in less irrigation by agricultural customers. 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 decline was primarily due to customers in fracking and certain manufacturing industries. Residential decrease was primarily the result of weaker use per customer, partially offset by customer growth.
- NSP-Minnesota's C&I electric sales were flat as a result of higher use for large customer class (particularly due to greater usage in the petroleum industry), and an increase in the number of customers in both the small and large classes, offset by lower use for small customers in various industries. The residential decrease was due to less use per customer, partially offset by increasing customer growth.

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Weather-normalized Natural Gas Decline

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use.

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 June 30		Six Months Ended June 30	
(Millions of Dollars)	2015	2014	2015	2014
Electric revenues	$2,213	$2,298	$4,438	$4,599
Electric fuel and purchased power	(905)	(1,041)	(1,855)	(2,109)
Electric margin	$1,308	$1,257	$2,583	$2,490

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

Electric Revenues

(Millions of Dollars)	Three Months Ended June 30 2015 vs. 2014	Six Months Ended June 30 2015 vs. 2014
Fuel and purchased power cost recovery	$(145)	$(255)
Estimated impact of weather	(12)	(37)
Conservation and DSM program revenues (offset by expenses)	(13)	(28)
Retail sales growth, excluding weather impact	(9)	(10)
Non-fuel riders [(a)] [(b)]	31	65
Retail rate increases [(b)]	25	48
PSCO earnings test refund	24	35
Transmission revenue	14	22
Other, net	—	(1)
Total decrease in electric revenues	$(85)	$(161)

Electric Margin

(Millions of Dollars)	Three Months Ended June 30 2015 vs. 2014	Six Months Ended June 30 2015 vs. 2014
Non-fuel riders [(a)] [(b)]	$31	$65
Retail rate increases [(b)]	25	48
PSCo earnings test refund	24	35
NSP-Wisconsin fuel recovery	3	9
Estimated impact of weather	(12)	(37)
Conservation and DSM program revenues (offset by expenses)	(13)	(28)
Retail sales decline, excluding weather impact	(9)	(10)

Other, net	2	11
Total increase in electric margin	$51	$93

(a) Increases relate primarily to the new CACJA rider in Colorado ($28 million and $52 million, respectively) and TCR rider in Minnesota ($5 million and $14 million, respectively).

(b) Increase due to rate proceedings in Minnesota, Texas, South Dakota, North Dakota, New Mexico, Wisconsin and Michigan. These increases were partially offset by a decline in Colorado retail base rates, which was more than offset by increased CACJA rider revenue as approved by the CPUC in the first quarter of 2015.

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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 June 30		Six Months Ended June 30	
(Millions of Dollars)	2015	2014	2015	2014
Natural gas revenues	$284	$369	$1,000	$1,249
Cost of natural gas sold and transported	(127)	(211)	(599)	(835)
Natural gas margin	$157	$158	$401	$414

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended June 30 2015 vs. 2014	Six Months Ended June 30 2015 vs. 2014
Purchased natural gas adjustment clause recovery	$(84)	$(234)
Estimated impact of weather	(2)	(19)
Conservation and DSM program revenues (offset by expenses)	(3)	(11)
Integrity rider (Colorado) and infrastructure rider (Minnesota), partially offset in expenses	11	18
Retail sales decline, excluding weather impact	(7)	(3)
Other, net	—	—
Total decrease in natural gas revenues	$(85)	$(249)

Natural Gas Margin

(Millions of Dollars)	Three Months Ended June 30 2015 vs. 2014	Six Months Ended June 30 2015 vs. 2014
Estimated impact of weather	$(2)	$(19)
Conservation and DSM program revenues (offset by expenses)	(3)	(11)
Retail sales decline, excluding weather impact	(7)	(3)
Integrity rider (Colorado) and infrastructure rider (Minnesota), partially offset in expenses	11	18
Other, net	—	2
Total decrease in natural gas margin	$(1)	$(13)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $8.7 million, or 1.5 percent, for the second quarter of 2015 and $34.4 million, or 3.0 percent, for the six months ended June 30, 2015. The year-to-date increase in O&M is 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 June 30 2015 vs. 2014	Six Months Ended June 30 2015 vs. 2014
Plant generation costs	$5	$21
Employee benefits	4	8
Nuclear plant operations	(1)	3
Other, net	1	2
Total increase in O&M expenses	$9	$34

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Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased $16.7 million for the second quarter of 2015 and $40.4 million for the six months ended June 30, 2015. The decreases were primarily attributable to lower electric and gas recovery rates at NSP-Minnesota and PSCo. Lower conservation and DSM program expenses are generally offset by lower revenues.

Depreciation and Amortization — Depreciation and amortization increased $19.3 million, or 7.6 percent, for the second quarter of 2015 and $46.5 million, or 9.3 percent, year-to-date. Increases were primarily attributed to normal system expansion and lower amortization of the excess depreciation reserve in Minnesota, partially offset by Minnesota's amortization of the Department of Energy settlement.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $13.5 million, or 11.6 percent, for the second quarter of 2015 and $25.4 million, or 10.5 percent, for the six months ended June 30, 2015. Increases were due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC decreased $14.9 million for the second quarter of 2015 and $27.6 million year-to-date. Decreases were 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 $4.8 million, or 3.5 percent, for the second quarter of 2015 and $10.7 million, or 3.8 percent, for the six months ended June 30, 2015. Increases were primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense increased $5.6 million for the second quarter of 2015 compared with the same period in 2014. The increase was primarily due to higher pretax earnings in second quarter of 2015, partially offset by decreased permanent plant-related adjustments in 2015 and a tax benefit for an income exclusion in 2014. The ETR was 35.8 percent for the second quarter of 2015 compared with 34.8 percent for the same period in 2014. The higher ETR for 2015 was primarily due to the adjustments referenced above.

Income tax expense decreased $46.6 million for the first six months of 2015 compared with the same period in 2014. The decrease in income tax expense was primarily due to lower pretax earnings in six months ended June 30, 2015, partially offset by decreased permanent plant-related adjustments in 2015, the successful resolution of a 2010-2011 IRS audit issue in 2014 and a tax benefit for an income exclusion in 2014. The ETR was 35.7 percent for the first six months of 2015, compared to 34.5 percent for the first six months of 2014 primarily due to these adjustments.

Public Utility Regulation and Legislation

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 1. of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2014, and Public Utility Regulation included in Item 2. of Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015, appropriately represent, in all material respects, the current status of public utility regulation, and are incorporated herein by reference.

NSP-Minnesota

Courtenay Wind Farm — NSP-Minnesota plans to move forward with construction and ownership of the Courtenay wind farm, a 200 MW project in North Dakota, pending regulatory approval. In May 2015, NSP-Minnesota filed for expedited regulatory approval in Minnesota and North Dakota. The total construction cost of the project is estimated to be approximately $300 million. On July 30, 2015, the MPUC approved the Courtenay wind purchase with recovery up to $300 million. NDPSC approval of the project is anticipated in August 2015.

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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 non-production tax credit 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 year-end 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.

NSP-Minnesota continues to execute on several aspects of the additional CAP resources approved by the MPUC in February 2015, including:

- Executed an agreement for 100 MW of distributed solar with Geronimo Energy LLC;
- Executed an agreement with Calpine Corporation for a 345 MW expansion at its Mankato Energy Center; and
- Initiated pre-construction tasks needed to construct a 215 MW Black Dog Unit 6 combustion turbine at the existing generation site.

Since the filing of the resource plan, NSP-Minnesota has completed several stakeholder workshops that provided information on the Plan and March supplement as well as other key topics of interest to stakeholders. This effort is intended to both focus and reduce formal information requests regarding the resource plan. In July, the Department of Commerce (DOC) filed comments on the Plan recommending that one of the Sherco units be retired in 2025, or alternatively, as early as 2020. A coalition of environmental intervenors filed comments recommending that Sherco Unit 1 close in 2021 and Unit 2 close in 2024. The current schedule calls for NSP-Minnesota to file reply comments on Sept. 2, 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 June 30, 2015, Xcel Energy has invested $942.8 million of its $1.1 billion share of the five CapX2020 transmission projects. The projects are as follows:

- Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 161/345 Kilovolt (KV) transmission line — 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 April 2015, the final portion of the project was placed in service.
- Brookings County, S.D. to Hampton, Minn. 345 KV transmission line — 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 — 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 MW of large-scale solar to its system by the end of 2016. NSP-Minnesota also offers small solar programs: a solar production incentive program for rooftop solar, called Solar*Rewards, and a community solar garden program that provides bill credits to participating subscribers, called Solar*Rewards Community. Additionally, the DOC offers the Made in Minnesota incentive program for small solar using products made in-state, which generates renewable energy credits for utilities including NSP-Minnesota.

During 2015, NSP-Minnesota sought policy guidance from the MPUC regarding the price and size of Solar*Rewards Community projects. The program was intended for projects one MW or less. Many proposals, however, were sized between 10 and 50 MW. In June 2015, the MPUC reviewed the Solar*Rewards Community program and voted to limit the size of solar installations eligible to participate in the program, more closely aligning the program with its original intent. The MPUC decision limits projects to five MW or less through Sept. 25, 2015. Subsequently, projects must be one MW or less.

Minnesota Legislation — In June 2015, the Minnesota governor signed the Jobs and Energy bill into law. Several approved mechanisms may provide additional options and opportunities in future rate cases, including the duration of future multi-year plans and more certainty regarding recovery of costs and the impact to customers. This bill provides:

- Increased flexibility for utilities to submit a multi-year plan (MYP) of up to five years;
- The potential for full capital recovery for all proposed years;
- O&M cost recovery based on an index;
- Distribution costs that facilitate grid modernization are eligible for rider recovery;
- Natural gas extension costs for unserved areas can be socialized and are eligible for rider recovery;
- Recovery of plant closure costs, should the MPUC order early plant closure; and
- Allows implementation of interim rates for the first and second years of the MYP.

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). 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. The NRC informed Xcel Energy in February 2015 that the final determination on the security finding was greater than green. In March 2015, Monticello was upgraded from Column 3 (degraded cornerstone) to Column 2 (regulatory response), based on the results of an NRC inspection in late 2014 to close out the flood control finding. Monticello will remain in Column 2 until the NRC performs an inspection and confirms that the white security finding can be closed. Upon closure of the white security finding, Monticello will be eligible to be upgraded to Column 1. Plants in Column 1 are subject to only a pre-defined set of basic NRC inspections. The NRC conducted an inspection on the security finding in late July 2015, the results of which are pending.

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 Certificate of Public Convenience and Necessity (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. In June 2015, the PSCW denied two requests for rehearing. Two groups have appealed the CPCN Order to county court. Court action is pending and the CPCN remains in full effect unless one of the parties seeks and receives a stay from the court and posts a bond to cover damages the utilities may incur due to delay. 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.

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PSCo

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 if it obtains CPUC approval of its separation plan.

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.

In April 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. In May 2015, PSCo sent Boulder a letter indicating its willingness to discuss a power supply arrangement with Boulder, but no formal offer was made. On July 7, 2015, Boulder filed an application with the CPUC requesting approval of Boulder's proposed separation plan.

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. In April 2015, the CPUC approved a settlement agreement between PSCo and all parties, which resolved all issues.

Cabin Creek Hydro Upgrade — PSCo filed 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. A final CPUC decision is expected in the fourth quarter of 2015.

SPS

Texas Legislation — In June 2015, the Texas Governor signed HB 1535 into law. As a result, SPS may reduce regulatory lag through earlier inclusion of certain capital additions in rate base, as well as expediting the implementation of new rates. Key provisions of the bill are as follows:

- Utilities may include actual and estimated post-test year capital additions up through 30-days before the filing date;
- A new natural gas generating unit may be included in rate base as long as it is in service before the proposed effective rate date;
- Rates will go into effect 155 days after filing (previously it was 185 days). If the case is not final by this date, then a utility can go back and surcharge; and
- Establishes time limits for the PUCT to rule on a new generation plant request for a certificate of convenience and necessity.

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Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, 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. The issue of how to apply the new FERC ROE methodology is being contested in various complaint proceedings. FERC is not expected to issue orders in any of these ROE complaint proceedings until 2016. See Note 5 to the consolidated financial statements for discussion of the SPS Wholesale Rate and MISO ROE complaints.

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.

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

At June 30, 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	$3,255	$7,932	$1,272	$715	$13,174
NSP-Minnesota	2	5,812	—	—	—	5,812
PSCo	1	2	—	—	—	2
		$9,069	$7,932	$1,272	$715	$18,988

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(Thousands of Dollars)	Options 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	$260	$—	$—	$—	$260

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

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

	Six Months Ended June 30	
(Thousands of Dollars)	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	3,472	(7,278)
Commodity trading contract additions and changes during period	(6,035)	3,700
Fair value of commodity trading net contract assets outstanding at June 30	$19,248	$26,936

At June 30, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.4 million. At June 30, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1.1 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1.1 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 June 30	VaR Limit	Average	High	Low
2015	$0.47	$3.00	$0.23	$1.30	$0.06
2014	0.42	3.00	0.77	1.69	0.06

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 13 percent of its 2015 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and sanctions against Russia. Alternate potential sources are expected to provide the flexibility to manage NSP-Minnesota's nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 34 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material beyond 2015.

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

At June 30, 2015 and 2014, a 100-basis-point change in the benchmark rate on Xcel Energy’s variable rate debt would impact pretax interest expense annually by approximately $4.5 million and $7.8 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries’ interest rate derivatives.

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NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At June 30, 2015, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates do not have an impact on earnings.

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

At June 30, 2015, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $3.4 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $4.5 million. At June 30, 2014, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $35.9 million, while a decrease in prices of 10 percent would have resulted in a decrease in credit exposure of $22.2 million.

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

Fair Value Measurements

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

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at June 30, 2015. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at June 30, 2015.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 3.2 percent and 34.8 percent of total assets and liabilities, respectively, measured at fair value at June 30, 2015.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $59.3 million and $12.5 million of estimated fair values, respectively, for FTRs held at June 30, 2015.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. Level 3 commodity derivative assets included no assets and no liabilities, for forwards held at June 30, 2015. There were no Level 3 options held at June 30, 2015.

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Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of private equity investments and real estate investments. Based on an evaluation of NSP-Minnesota’s ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling $204.8 million in the nuclear decommissioning fund at June 30, 2015 (approximately 11.1 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Liquidity and Capital Resources

Cash Flows

	Six Months Ended June 30	
(Millions of Dollars)	2015	2014
Cash provided by operating activities	$1,509	$1,040

Net cash provided by operating activities increased $469 million for the six months ended June 30, 2015 compared with the six months ended June 30, 2014. The increase was primarily due to changes in working capital, including income tax refunds received in 2015 compared to taxes paid in 2014, changes in regulatory assets and liabilities and higher net income, excluding amounts related to non-cash operating activities (e.g. depreciation, deferred tax expenses and a charge related to the Monticello LCM/EPU project).

	Six Months Ended June 30	
(Millions of Dollars)	2015	2014
Cash used in investing activities	$(1,431)	$(1,531)

Net cash used in investing activities decreased $100 million for the six months ended June 30, 2015 compared with the six months ended June 30, 2014. The decrease was primarily attributable to higher capital expenditures in 2014 related to CACJA projects and the impact of higher insurance proceeds related to Sherco Unit 3.

	Six Months Ended June 30	
(Millions of Dollars)	2015	2014
Cash (used in) provided by financing activities	$(22)	$484

Net cash used in financing activities was $22 million for the six months ended June 30, 2015 compared with net cash provided by financing activities of $484 million for the six months ended June 30, 2014, or a change of $506 million. The difference was primarily due to repayments of short-term debt in 2015 compared to proceeds in 2014 and less issued common stock, partially offset by a repayment of long-term debt in 2014.

Capital Requirements

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

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

As a result of this legislation, there will be material increased reporting requirements for certain volumes of derivative and swap activity. In April 2012, the CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. An entity may deal in utility operations-related swaps and not be required to register as a swap dealer provided that the aggregate gross notional amount of swap dealing activity (including utility operations-related swaps) does not exceed the general de minimis threshold and provided that the entity has not exceeded the special entity de minimis threshold (excluding utility operations-related swaps) of $25 million for the preceding 12 months. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that should exempt certain derivatives end users from much of the clearing and margin requirements. Xcel Energy does not expect to be materially impacted by the margining provisions. Xcel Energy is currently meeting all other reporting requirements.

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SPP FTR Margining Requirements — The SPP conducted its first annual FTR auction in the spring of 2014 associated with the implementation of the SPP Integrated Market. The process for transmission owners involves the receipt of Auction Revenue Rights (ARRs) and, if elected by the transmission owner, conversion of those ARRs to firm FTRs. SPP requires that the transmission owner post collateral for the conversion of ARRs to FTRs. At June 30, 2015, SPS had a $36 million letter of credit posted with SPP, which was a reduction from the initial requirement of $41 million.

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

- In January 2015, contributions of $90.0 million were made across four of Xcel Energy's pension plans;
- In 2014, contributions of $130.6 million were made across four of Xcel Energy's pension plans; and
- For future years, we anticipate contributions will be made as necessary.

Capital Sources

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

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At June 30, 2015, approximately $20.4 million of cash was held in these accounts.

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.75 billion and each credit facility terminates in October 2019.

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

As of July 27, 2015, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available	Cash	Liquidity
Xcel Energy Inc.	$1,000	$60	$940	$—	$940
PSCo	700	35	665	1	666
NSP-Minnesota	500	184	316	1	317
SPS	400	257	143	1	144
NSP-Wisconsin	150	—	150	5	155
Total	$2,750	$536	$2,214	$8	$2,222

[a] These credit facilities expire in October 2019.
[b] Includes outstanding commercial paper and letters of credit.

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

- $1 billion for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $400 million for SPS; and
- $150 million for NSP-Wisconsin.

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Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2015	Twelve Months Ended Dec. 31, 2014
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	451	1,020
Average amount outstanding	780	841
Maximum amount outstanding	1,072	1,200
Weighted average interest rate, computed on a daily basis	0.48 %	0.33 %
Weighted average interest rate at period end	0.48	0.56

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

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

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

During 2015, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In May, PSCo issued $250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- In June, Xcel Energy Inc. issued $250 million of 1.2 percent senior notes due June 1, 2017 and $250 million of 3.3 percent senior notes due June 1, 2025; and
- In June, NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024.

During 2015, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds; and
- SPS plans to issue approximately $200 million of first mortgage bonds.

Xcel Energy does not anticipate issuing any additional equity, beyond its dividend reinvestment program and benefit programs, for 2015-2019, based on its current capital expenditure plan. Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

Off-Balance-Sheet Arrangements

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

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Earnings Guidance

Xcel Energy's 2015 ongoing earnings guidance is $2.00 to $2.15 per share. Key assumptions related to 2015 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 0.5 percent.
- Weather-normalized retail firm natural gas sales are projected to decline approximately 2 percent.
- Capital rider revenue is projected to increase by $155 million to $165 million over 2014 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2014 levels.
- Depreciation expense is projected to increase $130 million to $150 million over 2014 levels.
- Property taxes are projected to increase approximately $60 million to $70 million over 2014 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2014 levels.
- AFUDC — equity is projected to decline approximately $30 million to $40 million from 2014 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 508 million shares.

Long-Term EPS and Dividend Growth Rate Objectives

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

- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on weather-normalized, ongoing 2014 EPS of $2.00;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis — Derivatives, Risk Management and Market Risk under Item 2.

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of June 30, 2015, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

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Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Additional Information

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

Item 1A — RISK FACTORS

Xcel Energy Inc.'s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2014, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended June 30, 2015:

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2015 — April 30, 2015	—	$—	—	—
May 1, 2015 — May 31, 2015	—	—	—	—
June 1, 2015 — June 30, 2015	—	—	—	—
Total	—		—	—

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

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Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
4.01*	Supplemental Indenture No. 8 dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $250,000,000 aggregate principal amount of 1.20% Senior Notes, Series due June 1, 2017 and $250,000,000 aggregate principal amount of 3.30% Senior Notes, Series due June 1, 2025. (Exhibit 4.01 to Form 8-K dated June 1, 2015 (file no. 001-03034)).
4.02*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250,000,000 principal amount of 2.90% First Mortgage Bonds, Series No. 28 due 2025. (Exhibit 4.01 to Form 8-K of PSCo dated May 12, 2015 (file no. 001-03280)).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

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SIGNATURES

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

XCEL ENERGY INC.

July 31, 2015	By:	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage Senior Vice President, Controller (Principal Accounting Officer)
		/s/ TERESA S. MADDEN Teresa S. Madden Executive Vice President, Chief Financial Officer (Principal Financial Officer)