XCEL ENERGY INC
Form 10-Q
October 30, 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 Sept. 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 October 26, 2015
Common Stock, $2.50 par value	507,496,978 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 Sept. 30		Nine Months Ended Sept. 30	
	2015	2014	2015	2014
Operating revenues				
Electric	$2,667,480	$2,616,351	$7,105,803	$7,215,699
Natural gas	216,019	236,649	1,216,146	1,485,464
Other	17,813	16,807	56,716	56,344
Total operating revenues	2,901,312	2,869,807	8,378,665	8,757,507
Operating expenses				
Electric fuel and purchased power	1,014,726	1,079,855	2,869,563	3,188,498
Cost of natural gas sold and transported	66,071	99,344	665,109	934,073
Cost of sales — other	8,203	8,012	26,416	24,783
Operating and maintenance expenses	565,984	568,391	1,746,093	1,714,138
Conservation and demand side management program expenses	57,314	75,172	165,260	223,552
Depreciation and amortization	280,121	255,395	827,821	756,645
Taxes (other than income taxes)	123,081	117,958	389,438	358,938
Loss on Monticello life cycle management/extended power uprate project	—	—	129,463	—
Total operating expenses	2,115,500	2,204,127	6,819,163	7,200,627
Operating income	785,812	665,680	1,559,502	1,556,880
Other income, net	1,626	1,404	5,748	4,687
Equity earnings of unconsolidated subsidiaries	8,162	7,401	24,360	22,650
Allowance for funds used during construction — equity	15,427	23,337	40,728	68,852
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,260, $5,737, $17,819 and $17,144, respectively	152,566	143,219	441,728	421,713
Allowance for funds used during construction — debt	(7,031)	(9,948)	(19,340)	(29,609)
Total interest charges and financing costs	145,535	133,271	422,388	392,104
Income before income taxes	665,492	564,551	1,207,950	1,260,965
Income taxes	239,029	195,969	432,490	435,998
Net income	$426,463	$368,582	$775,460	$824,967
Weighted average common shares outstanding:				
Basic	508,031	506,082	507,585	502,983
Diluted	508,427	506,365	507,976	503,213

Earnings per average common share:				
Basic	$0.84	$0.73	$1.53	$1.64
Diluted	0.84	0.73	1.53	1.64
Cash dividends declared per common share	$0.32	$0.30	$0.96	$0.90

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2015	2014	2015	2014
Net income	$426,463	$368,582	$775,460	$824,967
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $559, $567, $1,689 and $1,666, respectively	884	847	2,643	2,575
Derivative instruments:				
Net fair value decrease, net of tax of $(28), $(27), $(24) and $(22), respectively	(42)	(42)	(35)	(34)
Reclassification of losses to net income, net of tax of $446, $393, $1,210 and $1,115, respectively	706	558	1,891	1,693
	664	516	1,856	1,659
Marketable securities:				
Net fair value (decrease) increase, net of tax of $0, $1, $1 and $26, respectively	(1)	2	1	40
Other comprehensive income	1,547	1,365	4,500	4,274
Comprehensive income	$428,010	$369,947	$779,960	$829,241

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

	Nine Months Ended Sept. 30	
	2015	2014
Operating activities		
Net income	$775,460	$824,967
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	841,360	769,706
Conservation and demand side management program amortization	4,063	4,582
Nuclear fuel amortization	82,627	92,278
Deferred income taxes	429,091	433,224
Amortization of investment tax credits	(4,151)	(4,329)
Allowance for equity funds used during construction	(40,728)	(68,852)
Equity earnings of unconsolidated subsidiaries	(24,360)	(22,650)
Dividends from unconsolidated subsidiaries	29,434	27,130
Share-based compensation expense	29,765	16,536
Loss on Monticello life cycle management/extended power uprate project	129,463	—
Net realized and unrealized hedging and derivative transactions	18,808	(1,354)
Changes in operating assets and liabilities:		
Accounts receivable	85,276	(16,080)
Accrued unbilled revenues	182,425	112,406
Inventories	(47,659)	(57,677)
Other current assets	72,445	(25,901)
Accounts payable	(116,137)	(155,788)
Net regulatory assets and liabilities	116,068	162,134
Other current liabilities	60,293	14,683
Pension and other employee benefit obligations	(82,013)	(111,463)
Change in other noncurrent assets	2,374	44,009
Change in other noncurrent liabilities	(53,982)	(33,220)
Net cash provided by operating activities	2,489,922	2,004,341
Investing activities		
Utility capital/construction expenditures	(2,186,369)	(2,301,339)
Proceeds from insurance recoveries	27,237	6,000
Allowance for equity funds used during construction	40,728	68,852
Purchases of investments in external decommissioning fund	(773,260)	(499,493)
Proceeds from the sale of investments in external decommissioning fund	753,924	494,554
Investment in WYCO Development LLC	(832)	(2,220)
Other, net	(676)	(1,110)
Net cash used in investing activities	(2,139,248)	(2,234,756)
Financing activities		
Repayments of short-term borrowings, net	(955,500)	(62,000)
Proceeds from issuance of long-term debt	1,627,190	837,794
Repayments of long-term debt	(250,644)	(275,708)
Proceeds from issuance of common stock	5,298	178,639
Dividends paid	(452,217)	(417,586)

Net cash (used in) provided by financing activities	(25,873)	261,139
Net change in cash and cash equivalents	324,801	30,724
Cash and cash equivalents at beginning of period	79,608	107,144
Cash and cash equivalents at end of period	$404,409	$137,868
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(424,878)	$(407,186)
Cash received (paid) for income taxes, net	57,632	(4,950)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$284,864	$407,706
Issuance of common stock for reinvested dividends and 401(k) plans	39,169	42,772

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

	Sept. 30, 2015	Dec. 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$404,409	$79,608
Accounts receivable, net	741,230	826,506
Accrued unbilled revenues	546,067	728,492
Inventories	644,963	597,183
Regulatory assets	347,122	444,058
Derivative instruments	48,110	85,723
Deferred income taxes	352,712	246,210
Prepaid taxes	117,012	185,488
Prepayments and other	142,797	171,112
Total current assets	3,344,422	3,364,380
Property, plant and equipment, net	29,828,609	28,756,916
Other assets		
Nuclear decommissioning fund and other investments	1,807,692	1,832,640
Regulatory assets	2,812,172	2,774,216
Derivative instruments	54,743	53,775
Other	182,058	175,957
Total other assets	4,856,665	4,836,588
Total assets	$38,029,696	$36,957,884
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$457,474	$257,726
Short-term debt	64,000	1,019,500
Accounts payable	924,260	1,173,006
Regulatory liabilities	365,853	410,729
Taxes accrued	379,103	396,615
Accrued interest	143,124	158,536
Dividends payable	162,324	151,720
Derivative instruments	27,303	21,632
Other	561,579	475,119
Total current liabilities	3,085,020	4,064,583
Deferred credits and other liabilities		
Deferred income taxes	6,390,162	5,852,988
Deferred investment tax credits	69,545	73,696
Regulatory liabilities	1,169,294	1,163,429
Asset retirement obligations	2,550,930	2,446,631
Derivative instruments	173,588	183,936
Customer advances	228,479	256,945

Pension and employee benefit obligations	863,645	936,907
Other	263,452	264,653
Total deferred credits and other liabilities	11,709,095	11,179,185
Commitments and contingencies		
Capitalization		
Long-term debt	12,690,751	11,499,634
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 507,267,264 and 505,733,267 shares outstanding at Sept. 30, 2015 and Dec. 31, 2014, respectively	1,268,168	1,264,333
Additional paid in capital	5,873,440	5,837,330
Retained earnings	3,506,861	3,220,958
Accumulated other comprehensive loss	(103,639)	(108,139)
Total common stockholders' equity	10,544,830	10,214,482
Total liabilities and equity	$38,029,696	$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 Sept. 30, 2015 and 2014						
Balance at June 30, 2014	505,106	$1,262,764	$5,799,968	$2,961,406	$ (103,366)	$9,920,772
Net income				368,582		368,582
Other comprehensive income					1,365	1,365
Dividends declared on common stock				(152,601)		(152,601)
Issuances of common stock	318	796	9,135			9,931
Share-based compensation			6,611			6,611
Balance at Sept. 30, 2014	505,424	$1,263,560	$5,815,714	$3,177,387	$ (102,001)	$10,154,660
Balance at June 30, 2015	506,959	$1,267,398	$5,863,209	$3,243,645	$ (105,186)	$10,269,066
Net income				426,463		426,463
Other comprehensive income					1,547	1,547
Dividends declared on common stock				(163,247)		(163,247)
Issuances of common stock	308	770	8,665			9,435
Share-based compensation			1,566			1,566
Balance at Sept. 30, 2015	507,267	$1,268,168	$5,873,440	$3,506,861	$ (103,639)	$10,544,830

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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
Nine Months Ended Sept. 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				824,967		824,967
Other comprehensive income					4,274	4,274
Dividends declared on common stock				(455,563)		(455,563)
Issuances of common stock	7,452	18,631	175,960			194,591
Share-based compensation			20,441			20,441
Balance at Sept. 30, 2014	505,424	$1,263,560	$5,815,714	$3,177,387	$ (102,001)	$10,154,660
Balance at Dec. 31, 2014	505,733	$1,264,333	$5,837,330	$3,220,958	$ (108,139)	$10,214,482
Net income				775,460		775,460
Other comprehensive income					4,500	4,500
Dividends declared on common stock				(489,557)		(489,557)
Issuances of common stock	1,534	3,835	18,874			22,709
Share-based compensation			17,236			17,236
Balance at Sept. 30, 2015	507,267	$1,268,168	$5,873,440	$3,506,861	$ (103,639)	$10,544,830

See Notes to Consolidated Financial Statements

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

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of Sept. 30, 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 nine months ended Sept. 30, 2015 and 2014; and its cash flows for the nine months ended Sept. 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 Sept. 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 does not expect the implementation of ASU 2015-02 to have a material impact 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 (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)	Sept. 30, 2015	Dec. 31, 2014
Accounts receivable, net		
Accounts receivable	$793,188	$884,225
Less allowance for bad debts	(51,958)	(57,719)
	$741,230	$826,506

(Thousands of Dollars)	Sept. 30, 2015	Dec. 31, 2014
Inventories		
Materials and supplies	$291,301	$244,099
Fuel	212,728	183,249
Natural gas	140,934	169,835
	$644,963	$597,183

(Thousands of Dollars)	Sept. 30, 2015	Dec. 31, 2014
Property, plant and equipment, net		
Electric plant	$35,022,960	$33,203,139
Natural gas plant	4,818,049	4,643,452
Common and other property	1,615,290	1,611,486
Plant to be retired [(a)]	42,336	71,534
Construction work in progress	1,679,178	2,005,531
Total property, plant and equipment	43,177,813	41,535,142
Less accumulated depreciation	(13,724,333)	(13,168,418)
Nuclear fuel	2,414,986	2,347,422
Less accumulated amortization	(2,039,857)	(1,957,230)
	$29,828,609	$28,756,916

(a) PSCo's Cherokee Unit 3 was retired in August 2015. In 2017, PSCo expects to both early retire Valmont Unit 5 and convert Cherokee Unit 4 from a coal-fueled generating facility to natural gas, as approved by the Colorado Public Utilities Commission (CPUC). 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. 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 Sept. 30, 2015, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $13 million of income tax expense for the 2009 through 2011 claims, the recently filed 2013 claim, and the anticipated claim for 2014. As of Sept. 30, 2015, the IRS had begun the appeals process; however, the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy's 2009-2011 federal income tax returns expires in December 2016 following an extension to allow additional time for the appeals process. In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of Sept. 30, 2015, the IRS had not proposed any material adjustments to tax years 2012 and 2013.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Sept. 30, 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	2011

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As of Sept. 30, 2015, there were no state income tax audits in progress.

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

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

(Millions of Dollars)	Sept. 30, 2015	Dec. 31, 2014
Unrecognized tax benefit — Permanent tax positions	$15.8	$16.2
Unrecognized tax benefit — Temporary tax positions	60.6	50.3
Total unrecognized tax benefit	$76.4	$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)	Sept. 30, 2015	Dec. 31, 2014
NOL and tax credit carryforwards	$(39.2)	$(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 and audit progress 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 Sept. 30, 2015 and Dec. 31, 2014 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 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 the consolidated financial statements included in Xcel Energy Inc.'s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2015 and June 30, 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 $166.1 million, or 5.9 percent, consisting of $58.9 million and $125.2 million in 2014 and 2015, respectively, and an $18.0 million adjustment related to disallowance of certain Monticello Life Cycle Management (LCM)/Extended Power Uprate (EPU) costs. 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 and determined the Monticello EPU project was not yet used-and-useful, as final approval related to the full EPU uprate condition had not been received from the Nuclear Regulatory Commission (NRC) as of June 30, 2015. As a result, $13.8 million was excluded from final rates. Monticello subsequently received final NRC compliance approval in July 2015. 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 decisions resulted in a total estimated 2014 and 2015 annual rate increase of $149.4 million, or 5.3 percent.

The following table outlines the impact of the MPUC's July decision:

(Millions of Dollars)	MPUC July Decision
2014 and 2015 step 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 2014 and 2015 step increase	$ 149.4
Impact of interim rate effective March 3, 2015	(3.6)
Estimated revenue impact	$ 145.8

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 megawatts (MW). Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes allowance for funds used during construction (AFUDC). In 2008, project expenditures were initially estimated at approximately $320 million, excluding AFUDC.

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

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 – 2016 Transmission Cost Recovery (TCR) Rate Filing — In October 2015, NSP-Minnesota submitted its 2016 TCR filing with the MPUC, requesting recovery of $19.2 million of 2016 transmission investment costs not included in electric base rates. The 2016 TCR rider filing includes an option to keep within the TCR rider approximately $59.1 million of revenue requirements associated with two CapX2020 projects completed in 2015 or to include these revenue requirements in electric base rates during the interim rate implementation of the next electric rate case. If the MPUC opts to maintain the projects in the rider, the TCR rider revenue requirements would increase to $78.3 million.

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

NSP-Minnesota – South Dakota Infrastructure Rider — In October 2015, NSP-Minnesota filed its 2016 infrastructure rider filing with the SDPUC, requesting approval for recovery of $10.3 million in 2016 revenue requirements for rates effective Jan. 1, 2016. As part of the South Dakota 2015 electric rate case, the infrastructure rider was refreshed with new projects and was also expanded as a mechanism to allow for possible recovery of other investments related to generation, transmission, and distribution. A SDPUC decision is expected in the fourth quarter of 2015.

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NSP-Wisconsin

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

Wisconsin 2016 Electric and Gas Rate Case — In May 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 ROE 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.

On Oct. 1, 2015, the PSCW Staff and other intervenors, including the Citizens Utility Board, filed their direct testimony in the case. The PSCW Staff recommended an electric rate increase of $10.4 million, or 1.5 percent, and a gas rate increase of $3.0 million, or 2.5 percent, based on a ROE of 10.0 percent and an equity ratio of 52.5 percent. The Citizens Utility Board recommended a ROE of 8.75 percent. None of the intervenors presented a complete revenue requirements analysis. The majority of the PSCW Staff adjustments relate to ROE, compensation issues and capital related forecast disputes.

Key dates in the procedural schedule are as follows:

- Initial Brief — Nov. 12, 2015;
- Reply Brief — Nov. 19, 2015;
- A PSCW decision is anticipated in December 2015; and
- New rates effective on or about Jan. 1, 2016.

PSCo

Pending Regulatory Proceedings — 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 (MYP) and an equity ratio of 56 percent. The rate case requests a ROE of 10.1 percent for 2015 and 2016 and 10.3 percent for 2017, and a rate base of $1.26 billion for 2015, $1.31 billion for 2016 and $1.36 billion for 2017.

PSCo 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

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In June 2015, the CPUC Staff (Staff) and the Office of Consumer Counsel (OCC) issued their 2015 base rate recommendations. The following table reflects the current positions of Staff and OCC:

(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 HTY	(10.5)	(16.4)
Operating and maintenance (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

In July 2015, PSCo filed rebuttal testimony, maintaining its request for a multi-year plan and requested ROEs and reflecting the most recent sales forecast. 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.

Interim rates, subject to refund, were also implemented, effective Oct. 1, 2015, based on PSCo's direct testimony. PSCo is expecting the ALJ's Recommended Decision in November 2015. The final CPUC decision is expected no later than January 2016.

PSCo — Annual Electric Earnings Test — 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 Sept. 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. For the years 2015 through 2020, the annual electric energy savings goal is 400 GWh per year with an annual earnings limit of $84.3 million.

In July 2015, the CPUC approved PSCo's 2015-2016 DSM plan:

- 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.

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 June 2015, SPS filed rebuttal testimony supporting a revised rate increase of approximately $42.1 million, or 4.4 percent.

On Oct. 12, 2015, the administrative law judges (ALJs) issued their Proposal for Decision (PFD) and recommended a rate increase of approximately $1.2 million, based on a ROE of 9.70 percent and an equity ratio of 53.97 percent.

The following table reflects the positions of Alliance of Xcel Municipalities (AXM), the Office of Public Utility Counsel (OPUC), the PUCT Staff (Staff), SPS as well as the estimated recommendation of the ALJs:

(Millions of Dollars)	AXM	OPUC	Staff	SPS Rebuttal Testimony	ALJs' PFD (a)
SPS' revised rate request	$58.9	$58.9	$58.9	$ 58.9	$42.1
Investment for capital expenditures — post-test year adjustments	(11.3)	(23.8)	(23.8)	—	(16.7)
Lower ROE	(10.9)	(13.5)	(12.1)	—	(6.3)
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)	(5.3)
Depreciation expense	(13.3)	—	—	—	(3.9)
Property taxes	—	(1.2)	(4.4)	(1.8)	(3.7)
Revenue adjustments	(2.2)	(0.2)	—	—	—
Wholesale load reductions	(13.2)	—	(11.1)	—	—
Southwest Power Pool (SPP) transmission expansion plan	—	—	—	(7.3)	(4.2)
Other, net	(1.7)	(0.6)	(2.2)	(1.8)	(0.6)
Total recommendation	$(13.6)	$1.8	$(2.6)	$ 46.4	$1.4
Adjustment to move rate case expenses to a separate docket	—	—	—	(4.3)	(0.2)
Recommendation, excluding rate case expenses	$(13.6)	$1.8	$(2.6)	$ 42.1	$1.2

[a] The ALJs’ recommendation reflects proposed adjustments to SPS’ rebuttal testimony, as of Oct. 12, 2015, which supports a $42.1 million rate increase.

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SPS subsequently filed a letter notifying the PUCT it had concerns regarding the calculation. On Oct. 28, 2015, the Staff issued a revised calculation reflecting corrections to the PFD. The ALJs' revised recommended rate increase is $14.4 million.

New rates will be made effective retroactive to June 11, 2015 as established by the PUCT. A PUCT decision is expected in December 2015.

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

SPS – New Mexico 2015 Electric Rate Case — In October 2015, SPS filed an electric rate case with the NMPRC for a net increase in base rates of approximately $24.3 million for the New Mexico retail jurisdiction. The proposed net amount reflects an increase in non-fuel base rates of $45.4 million and a decrease in base fuel revenue of approximately $21.1 million. The decrease in base fuel revenue will be reflected in adjustments collected through the fuel and purchased power adjustment clause. The rate filing is based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric jurisdictional rate base of approximately$734 million and an equity ratio of 53.97 percent.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	Request
2015 base period deficiency	$19.7
Capital expenditures — post-test year adjustments	12.3
Depreciation, higher rates reflecting changes in depreciable lives, interim retirements and net salvage	3.7
Transmission revenue and expense, including charges paid to SPP for construction of regionally shared transmission projects	2.0
ROE, reflecting an increase from 9.96 percent to 10.25 percent	1.6
Rider revenue adjustments - gross receipts tax	1.3
Other, net	4.8
Requested rate increase	$45.4

A NMPRC decision and implementation of final rates is anticipated in the second half of 2016. In June 2015, the NMPRC dismissed a rate case filing using a future test year based on new precedent. SPS has appealed that decision to the New Mexico Supreme Court.

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

Midcontinent Independent System Operator, Inc. (MISO) ROE Complaints/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against certain 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.

Subsequently, the FERC issued and upheld 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 ROE complaint was set for full hearing procedures. The complainants and intervenors filed testimony recommending a ROE between 8.67 percent and 9.54 percent. The FERC staff recommended a ROE of 8.68 percent.

The MISO TOs recommended a ROE not less than 10.8 percent. An ALJ initial decision is anticipated to be issued by November 2015 and a FERC order is expected to be issued no earlier than 2016.

Certain MISO TOs requested FERC approval of a 50 basis point RTO membership ROE adder, which was approved effective Jan. 6, 2015, 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. Certain intervenors sought rehearing of the FERC order granting the ROE adder; FERC action is pending.

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Certain intervenors filed a second complaint in February 2015 to reduce the MISO region ROE to 8.67 percent, prior to an adder. A hearing has been set, and a refund effective date of Feb. 12, 2015 was established. The complainants and intervenors filed direct testimony in September 2015 recommending ROEs between 8.72 percent and 9.13 percent. The MISO TOs filed answering testimony on Oct. 20, 2015, recommending a ROE of not less than 10.75 percent. FERC staff is expected to file testimony in November 2015, and a hearing is scheduled for February 2016. An ALJ initial decision is expected in June 2016 with a FERC decision in late 2016 or in 2017. Currently, the ROE refund obligation initiated under the November 2013 complaint is effective through May 2016. The MISO TOs sought rehearing of the FERC decision to allow back-to-back complaints. NSP-Minnesota and NSP-Wisconsin sought rehearing of the FERC's decision not to order changes to the ROE used by non-jurisdictional MISO transmission owners (more than 20 municipal, cooperative and other utilities who are not respondents to the ROE complaints), which equals the ROE presently used by the jurisdictional MISO TOs. FERC action is pending.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE as of Sept. 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 – Global Settlement Agreement — In August 2015, SPS, Golden Spread Electric Cooperative, Inc. (Golden Spread), four New Mexico Cooperatives, West Texas Municipal Power Agency (WTMPA), Public Service Company of New Mexico (PNM) and Tri-County Electric Cooperative, Inc. (Tri-County) filed a settlement agreement with the FERC that would provide a comprehensive resolution of nine pending matters in dispute between SPS and these wholesale production and transmission customers, including the 2004 FERC Complaint Case, the Wholesale Rate Complaints, the 2015 Formula Rate Change Filing and the Sale of Texas Transmission Assets as discussed below. Key terms of the settlement agreement include:

- A settlement payment to Golden Spread for $44.9 million and withdrawal of the SPS and the New Mexico Cooperatives' requests for rehearing of the August 2013 FERC order ruling that SPS is a 3 coincident peak (CP) system;
- A settlement payment to PNM of $4.2 million and the withdrawal of the PNM request for rehearing of the August 2013 FERC order denying PNM's challenge to the 2008 FERC ruling regarding SPS' fuel cost adjustment practices;
- Withdrawal of the Golden Spread Wholesale Rate Complaints, resulting in no change to the then-effective production and transmission ROEs for the period April 20, 2012 through Oct. 19, 2014, and withdrawal of the SPS appeal of the FERC orders in those proceedings to the United States District Court of Appeals for the District of Columbia Circuit (D.C. Circuit);
- A reduction in the SPS transmission ROE to 10.5 percent (including the 50 basis point SPP regional transmission organization membership adder) and the production ROE in the Golden Spread and New Mexico Cooperatives production formula rates to 10.0 percent effective Oct. 20, 2014, and establishment of a limited moratorium that precludes any increase or decrease in these effective ROEs through 2019;
- Utilization of the 12 CP production cost allocation methodology in the Golden Spread, New Mexico Cooperatives and WTMPA production formula rates and a moratorium precluding all settlement parties from seeking to change from the 12 CP methodology during the remaining term of the Golden Spread production contract (currently scheduled to expire in May 2019);
- SPS agrees to reduce its production formula rates retroactive to Jan. 1, 2015 to reflect full year implementation of reduced depreciation and certain other costs; the FERC had allowed these reductions to be effective July 1, 2015;
- SPS agrees to make certain revisions to its transmission formula rate, effective Jan. 1, 2016, to provide for a sharing of the wholesale portion of any gain on a future sale of transmission assets; other parties agree not to challenge the non-sharing of the gain SPS recorded on prior and current transmission asset transactions with Sharyland Distribution and Transmission Services, LLC (Sharyland) and Oncor Electric Delivery Company LLC;
- SPS agrees not to file with FERC to increase transmission depreciation rate rates effective prior to Jan. 1, 2017; and

- SPS agrees not to transfer Tri-County from its current stated rate production service agreement to a production formula rate effective prior to Jan. 1, 2017. Tri-County agrees that it will not contest implementation of the formula rate as of that date.

On Oct. 29, 2015, the FERC issued an order approving the settlement agreement. The terms are effective 30 days after issuance. As a result of the settlement, SPS expects to recognize a net gain of approximately $7.9 million in the fourth quarter of 2015. The settlement also resolves the following:

2004 FERC Complaint Case Orders — In August 2013, the FERC issued an order related to a 2004 complaint case brought by Golden Spread, a wholesale cooperative customer, and PNM, a former wholesale customer, and also issued an Order on Initial Decision in a subsequent 2006 production rate case filed by SPS.

The original complaints included two key components: 1) a base rate complaint, including the appropriate demand-related CP cost allocator; and 2) a claim regarding alleged inappropriate fuel cost adjustment practices. The FERC had determined in April 2008 that the demand-related cost allocator and fuel cost adjustment practices utilized by SPS were appropriate.

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In the August 2013 Orders, the FERC 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 CP rather than a 12 CP system. The FERC also clarified its previous ruling on fuel cost adjustment practices and reaffirmed that the refunds in question should only apply to firm requirements customers.

In September 2013, SPS, the New Mexico Cooperatives and PNM each filed requests for rehearing of the FERC ruling on the CP allocation and/or refund decision. As of Dec. 31, 2014, SPS had accrued $50.4 million related to the August 2013 Orders and an additional $1.9 million of principal and interest has been accrued during 2015.

Wholesale Rate Complaints — In April 2012, Golden Spread 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 formula rate ROE of 11.27 percent are unjust and unreasonable, and requested that the base 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 base ROE in the SPS production formula rate for Golden Spread and transmission formula rates be reduced to 9.15 percent and 9.65 percent, respectively, effective July 19, 2013. In June 2014, the FERC issued orders consolidating these ROE complaints, setting the complaints for hearing procedures and granting the complainant's requested refund effective dates. SPS subsequently sought rehearing. In May 2015, FERC denied rehearing. In July 2015, SPS appealed the FERC orders to the D.C. Circuit.

A third ROE rate complaint was filed in October 2014 by Golden Spread, along with the New Mexico Cooperatives and WTMPA, requesting that the ROE in the SPS production formula rates for Golden Spread and the New Mexico Cooperatives and SPS transmission formula rate, be reduced 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. SPS subsequently sought rehearing. FERC has not acted on the SPS rehearing request.

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

Sale of Texas Transmission Assets — In March 2013, SPS reached an agreement to sell certain segments of SPS' transmission lines and two related substations to Sharyland. In 2013, SPS received all necessary regulatory approvals for the transaction. In December 2013, SPS received $37.1 million and recognized a pre-tax gain of $13.6 million and regulatory liabilities for retail jurisdictional gain sharing of $7.2 million. The gain is reflected in the consolidated statement of income as a reduction to O&M expenses. In December 2014, Golden Spread submitted a preliminary challenge under the SPS transmission formula rate procedures asserting the gain should be shared with wholesale transmission customers. SPS disputed this claim. In October 2015, the FERC denied rehearing on the matter.

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 Reports on Form 10-Q for the quarterly periods ended March 31, 2015 and June 30, 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 Sept. 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.

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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 Sept. 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)	Sept. 30, 2015	Dec. 31, 2014
Guarantees issued and outstanding	$12.9	$13.9
Current exposure under these guarantees	0.1	0.2
Bonds with indemnity protection	42.5	31.4

Other Indemnification Agreements

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

Environmental Contingencies

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

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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. In fall 2015, the ground water remedy was initiated at the site with the installation of groundwater wells and the start of construction on the groundwater treatment plant. The final design for the Phase I remedy was approved by the EPA in September 2015. The current cost estimate for the cleanup of the Phase I Project Area is approximately $57 million, of which approximately $39 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 (AOC) for the Wet Dredge pilot study with the EPA. In early 2015, NSP-Wisconsin entered into an AOC to construct a breakwater at the site to serve as wave attenuation and containment for a wet dredge pilot study and full scale sediment remedy at the site. Construction of the breakwater is underway with anticipated completion in early 2016. A wet dredge pilot study is anticipated to commence in summer 2016.

In August 2012, NSP-Wisconsin also filed litigation against other PRPs for their share of the cleanup costs for the Ashland site. 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 entered into 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. Trial with the remaining PRPs for this matter, County of Ashland and City of Ashland, took place in May 2015. In September 2015, the Court ruled that the County of Ashland is not a liable party and the City of Ashland, although a liable party, is not required to contribute any funds to the cleanup of the site. NSP-Wisconsin filed a notice of appeal with the Seventh Circuit Court of Appeals in October 2015.

At Sept. 30, 2015 and Dec. 31, 2014, NSP-Wisconsin had recorded a liability of $95.7 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 $16.6 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 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.

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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 through 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 December 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. NSP-Minnesota is undertaking further investigation of the location of the historic MGP site and nearby properties. At this time, NSP-Minnesota's investigation of the site is considered preliminary as information is still being gathered.

As of Sept. 30, 2015, NSP-Minnesota had recorded a liability of $1.4 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.

Environmental Requirements

Water

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) — In September 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. Xcel Energy is currently reviewing the final rule and cannot predict, at this time, whether the costs of compliance with the final rule will have a material impact on the results of operations, financial position or cash flows. Xcel Energy believes that compliance costs would be recoverable through regulatory mechanisms.

Federal 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 went into effect in August 2015. On Oct. 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule, pending further legal proceedings.

Air

Green House Gas (GHG) Emission Standard for Existing Sources — In June 2014, the EPA published its proposed rule on GHG emission standards for existing power plants. A final rule was published in October 2015. States must develop implementation plans by September 2016, with the possibility of an extension to September 2018. If a state decides not to submit a plan, the EPA will prepare a federal plan for the state. In addition, the EPA published a proposed model federal plan and will provide a 90-day public comment period on the federal plan once it has been published in the Federal Register. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants in the state achieve the EPA's state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets. The plan will likely require additional emission reductions in states in which Xcel Energy operates. Until Xcel Energy has reviewed the final rule and has more information about state implementation plans (SIPs), Xcel Energy cannot predict whether the costs of compliance with the final rule will have a material impact on the results of operations, financial position or cash flows. Xcel Energy believes that compliance costs will be recoverable through regulatory mechanisms.

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GHG New Source Performance Standard (NSPS) Proposal — In January 2014, the EPA re-proposed a GHG NSPS for newly constructed power plants which would set performance standards (maximum carbon dioxide emission rates) for coal- and natural gas-fired power plants. For coal power plants, the NSPS requires an emissions level equivalent to partial carbon capture and storage (CCS) technology; for natural gas-fired power plants, the NSPS reflects emissions levels from combined cycle technology with no CCS. The NSPS does not apply to modified or reconstructed existing power plants. In addition, installation of control equipment on existing plants would not constitute a “modification” to those plants under the NSPS program. The final rule was published in October 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.

GHG NSPS for Modified and Reconstructed Power Plants — In June 2014, the EPA published a proposed NSPS that would apply to GHG emissions from power plants that are modified or reconstructed. A final rule was published in October 2015. A modification is a change to an existing source that increases the maximum achievable hourly rate of emissions. A reconstruction involves the replacement of components at a unit to the extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable unit. The standards do not require installation of CCS technology. Instead, the standard for coal-fired power plants requires a combination of best operating practices and equipment upgrades. The standards for natural gas-fired power plants require emissions standards based on efficient combined cycle technology. These requirements would only apply if Xcel Energy were to modify or reconstruct an existing power plant in the future in a way that triggers applicability of this rule.

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 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 not have a material impact on the results of operations, financial position or cash flows.

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. In June 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.

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Industrial Boiler (IB) Maximum Achievable Control Technology (MACT) Rules — In 2011, the EPA finalized IB MACT rules to regulate boilers and process heaters fueled with coal, biomass and liquid fuels, which would apply to NSP-Wisconsin's Bay Front Units 1 and 2. The project to meet the requirements was completed in September 2015 with an estimated cost of approximately $20 million.

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 their first regional haze SIPs, Colorado, Minnesota and Texas identified the Xcel Energy facilities that will have to reduce SO_2, NOx and PM emissions under BART and set emissions limits for those facilities.

PSCo

In 2011, the Colorado Air Quality Control Commission approved a SIP (the Colorado SIP) that included the Clean Air Clean Jobs Act (CACJA) emission reduction plan as satisfying regional haze requirements for the facilities included in the CACJA plan. In addition, the Colorado SIP included a BART determination for Comanche Units 1 and 2. The EPA approved the Colorado SIP in 2012. Emission controls at Hayden Unit 1 and Hayden Unit 2 will be placed into service in late 2015 and late 2016, respectively, at an estimated combined cost of $82.4 million. PSCo anticipates these costs will be fully recoverable through regulatory mechanisms.

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. In September 2015, in response to a motion filed by WildEarth Guardians and the EPA, the 10th Circuit issued an order dismissing the case.

In 2010, two environmental groups petitioned the U.S. Department of the Interior (DOI) to certify that 12 coal-fired boilers and one coal-fired cement kiln in Colorado are contributing to visibility problems in Rocky Mountain National Park. The following PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege 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. In October 2014, the Eighth Circuit set a briefing schedule that was completed in February 2015. The Eighth Circuit heard arguments in September 2015 and a decision is anticipated in early 2016. If this litigation ultimately results in further EPA proceedings concerning the Minnesota SIP, such proceedings may consider whether SCRs should be required for Sherco Units 1 and 2.

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SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas developed a SIP (the Texas SIP) that finds the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs. 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 has indicated that it expects 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.

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. In

October 2015, the EPA proposed a rule that would set the agreed-upon SO_2 emission limits, which public comments due in November 2015. 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) made recommendations for unclassified and nonattainment areas to the EPA in September 2015. The EPA's final decision is expected 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.

Revisions to the NAAQS for Ozone — In October 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where Xcel Energy operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota and meet the 70 ppb level in the Texas panhandle. In documents issued with the new standard, the EPA projects that both areas will meet the new standard. Current monitored air quality concentrations in areas of Wisconsin, where Xcel Energy operates, are also below the new standard. The Denver Metropolitan Area is currently not meeting the prior ozone standard and will therefore not meet the new, more stringent, standard. If not in attainment, impacted areas would study the sources of nonattainment and make emission reduction plans to attain the new standards. These plans would be due to the EPA in 2020. In conjunction with CACJA, Xcel Energy has or plans to shut down coal-fired plants in the Denver area, has installed NOx controls on Pawnee and Hayden Unit 1 and will finish installing NOx controls on Hayden Unit 2 in 2016. The final designation of nonattainment areas will be made in late 2017 based on air quality data years 2014-2016. Xcel Energy cannot evaluate the impacts of this ruling in Colorado until the designation of nonattainment areas is made and any required state plan has been developed. Xcel Energy believes that, should NOx 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.

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.

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 Benson Power, LLC (Benson Power), as assignee of Fibrominn, LLC. Under this agreement, NSP-Minnesota is charged for certain costs of transporting biomass fuels that are delivered to Benson Power’s generation facility. Benson Power also sought additional cost reimbursement for certain transportation, handling and other costs incurred since 2007 totaling approximately $20 million. In August 2015, a settlement was reached regarding this dispute. No loss was recorded related to the terms of the settlement agreement.

Gas Trading Litigation — e prime, inc. (e prime) is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing, but has not engaged in natural gas trading or marketing activities since 2003. Thirteen lawsuits were commenced against e prime and Xcel Energy (and NSP-Wisconsin, in two instances) between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. The cases were consolidated in U.S. District Court in Nevada. In 2009, five of the cases were settled and one was dismissed. The U.S. District Court in 2011 issued an order dismissing entirely six of the remaining seven lawsuits, and partially dismissing the seventh. Plaintiffs appealed the dismissals to the U.S. Court of Appeals for the Ninth Circuit, which reversed the District Court. The matter was ultimately heard by the U.S. Supreme Court in early 2015, which agreed with the Ninth Circuit and remanded the matter to the U.S. District Court. In September 2015, the District Court held a status conference and set deadlines for certain litigation related activities in 2016. A trial date has not yet been set, but is not expected to occur prior to late 2016 or early 2017. Xcel Energy and e prime have concluded that a loss is remote with respect to this matter.

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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 Department of Energy’s (DOE) 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. 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 Sept. 30, 2015. In May 2015, NSP-Minnesota submitted a claim for an additional $13.2 million, and the DOE subsequently determined that NSP-Minnesota is entitled to reimbursement of $13.1 million. Payment of this amount is expected by the end of 2015. Amounts received from the installments, except for approved reductions such as legal costs, will be subsequently returned to customers through a reduction of future rate increases or credited through another regulatory mechanism.

Other Commitments

Limited Partnership Investment — In October 2015, Energy Impact Fund Investment, LLC (Energy Impact LLC), a wholly-owned non-utility subsidiary of Xcel Energy Inc., entered into a subscription agreement for a limited partnership interest, committing Energy Impact LLC to up to $50 million of total future investments in the newly formed Energy Impact Fund Limited Partnership (Energy Impact Fund LP) over the next five years. Along with the capital contributions of the other limited partners, who are primarily investor-owned utilities or their affiliates, the funding is expected to be used to make private equity investments in entities that are active developers and producers of new and emerging energy technologies applicable to utility operations, products and services. Xcel Energy expects to use the equity method to account for its interest in Energy Impact Fund LP.

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

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

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

(Amounts in Millions, Except Interest Rates)	Three Months Ended	Twelve Months Ended

	Sept. 30, 2015	Dec. 31, 2014
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	64	1,020
Average amount outstanding	272	841
Maximum amount outstanding	478	1,200
Weighted average interest rate, computed on a daily basis	0.46 %	0.33 %
Weighted average interest rate at period end	0.38	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 Sept. 30, 2015 and Dec. 31, 2014, there were $39 million and $61 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.

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

At Sept. 30, 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	$64	$936
PSCo	700	5	695
NSP-Minnesota	500	24	476
SPS	400	10	390
NSP-Wisconsin	150	—	150
Total	$2,750	$103	$2,647

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

Long-Term Borrowings

During the nine months ended Sept. 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;
- In June, NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024;
- In August, NSP-Minnesota issued $300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and $300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045; and
- In September, SPS issued $200 million of 3.3 percent first mortgage bonds due June 15, 2024.

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.

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.

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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 $298.4 million and $312.1 million at Sept. 30, 2015 and Dec. 31, 2014, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $87.3 million and $74.1 million at Sept. 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 Sept. 30, 2015 and Dec. 31, 2014:

	Sept. 30, 2015				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$33,681	$33,681	$—	$—	$33,681
Commingled funds	351,676	—	381,230	—	381,230
International equity funds	217,003	—	188,853	—	188,853
Private equity investments	98,133	—	—	145,695	145,695
Real estate	49,151	—	—	71,976	71,976
Debt securities:					
Government securities	24,557	—	21,423	—	21,423
U.S. corporate bonds	70,311	—	61,874	—	61,874
International corporate bonds	14,099	—	13,059	—	13,059
Municipal bonds	210,728	—	215,014	—	215,014
Asset-backed securities	2,834	—	2,836	—	2,836
Mortgage-backed securities	11,734	—	12,077	—	12,077
Equity securities:					
Common stock	386,176	533,431	—	—	533,431
Total	$1,470,083	$567,112	$896,366	$217,671	$1,681,149

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $80.3 million of equity investments in unconsolidated subsidiaries and $46.3 million of miscellaneous investments.

	Dec. 31, 2014				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$24,184	$24,184	$—	$—	$24,184
Commingled funds	470,013	—	465,615	—	465,615
International equity funds	80,454	—	78,721	—	78,721
Private equity investments	73,936	—	—	101,237	101,237
Real estate	43,859	—	—	64,249	64,249
Debt securities:					
Government securities	30,674	—	28,808	—	28,808
U.S. corporate bonds	81,463	—	77,562	—	77,562
International corporate bonds	16,950	—	16,341	—	16,341

Municipal bonds	242,282	—	249,201	—	249,201
Asset-backed securities	9,131	—	9,250	—	9,250
Mortgage-backed securities	23,225	—	23,895	—	23,895
Equity securities:					
Common stock	369,751	564,858	—	—	564,858
Total	$1,465,922	$589,042	$949,393	$165,486	$1,703,921

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

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

(Thousands of Dollars)	July 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets [a]	Sept. 30, 2015
Private equity investments	$133,993	$3,066	$—	$8,636	$145,695
Real estate	70,834	1,501	(1,719)	1,360	71,976
Total	$204,827	$4,567	$(1,719)	$9,996	$217,671

(Thousands of Dollars)	July 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Asset [a]	Sept. 30, 2014
Private equity investments	$81,123	$11,125	$—	$4,756	$97,004
Real estate	65,658	1,530	(5,876)	2,661	63,973
Total	$146,781	$12,655	$(5,876)	$7,417	$160,977

(Thousands of Dollars)	Jan. 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets [a]	Sept. 30, 2015
Private equity investments	$101,237	$24,197	$—	$20,261	$145,695
Real estate	64,249	9,633	(4,341)	2,435	71,976
Total	$165,486	$33,830	$(4,341)	$22,696	$217,671

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Asset [a]	Sept. 30, 2014
Private equity investments	$62,696	$22,078	$—	$12,230	$97,004
Real estate	57,368	5,386	(5,876)	7,095	63,973
Total	$120,064	$27,464	$(5,876)	$19,325	$160,977

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

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

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$—	$—	$21,423	$21,423
U.S. corporate bonds	—	15,398	51,317	(4,841)	61,874
International corporate bonds	—	2,976	9,109	974	13,059

Municipal bonds	1,260	27,500	44,594	141,660	215,014
Asset-backed securities	—	—	2,836	—	2,836
Mortgage-backed securities	—	—	—	12,077	12,077
Debt securities	$1,260	$45,874	$107,856	$171,293	$326,283

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.

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At Sept. 30, 2015, accumulated other comprehensive losses related to interest rate derivatives included $3.7 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 Sept. 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 nine months ended Sept. 30, 2015 and 2014.

At Sept. 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.

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

(Amounts in Thousands) [a][b]	Sept. 30, 2015	Dec. 31, 2014
Megawatt hours of electricity	76,323	56,361
Million British thermal units of natural gas	13,709	927
Gallons of vehicle fuel	176	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 nine months ended Sept. 30, 2015 and 2014, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 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 Losses Recognized During the Period in
(Thousands of Dollars)				Regulatory	

	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss		Assets and (Liabilities)		Income	
Derivatives designated as cash flow hedges								
Interest rate	$—	$—	$1,118	(a)	$—		$—	
Vehicle fuel and other commodity	(70)	—	34	(b)	—		—	
Total	$(70)	$—	$1,152		$—		$—	
Other derivative instruments								
Commodity trading	$—	$—	$—		$—		$(3,460)	(c)
Electric commodity	—	(2,403)	—		2,860	(d)	—	
Natural gas commodity	—	(2,978)	—		—		(405)	(e)
Total	$—	$(5,381)	$—		$2,860		$(3,865)	

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(Thousands of Dollars)	Nine Months Ended Sept. 30, 2015 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 Losses Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$3,013 (a)	$—	$—
Vehicle fuel and other commodity	(59)	—	88 (b)	—	—
Total	$(59)	$—	$3,101	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$(5,896) (c)
Electric commodity	—	(16,611)	—	16,020 (d)	—
Natural gas commodity	—	(3,366)	—	8,685 (e)	(9,455) (e)
Total	$—	$(19,977)	$—	$24,705	$(15,351)

(Thousands of Dollars)	Three Months Ended Sept. 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	$—	$—	$967 (a)	$—	$—
Vehicle fuel and other commodity	(69)	—	(16) (b)	—	—
Total	$(69)	$—	$951	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$(1,656) (c)
Electric commodity	—	(3,391)	—	6,629 (d)	—
Natural gas commodity	—	(2,455)	—	—	(209) (d)
Total	$—	$(5,846)	$—	$6,629	$(1,865)

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(Thousands of Dollars)	Nine Months Ended Sept. 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	$—	$—	$2,869 (a)	$—	$—
Vehicle fuel and other commodity	(56)	—	(61) (b)	—	—
Total	$(56)	$—	$2,808	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$1,266 (c)
Electric commodity	—	(17,240)	—	(18,641) (d)	—
Natural gas commodity	—	13,603	—	(18,840) (e)	(5,575) (e)
Other commodity	—	—	—	—	643 (c)
Total	$—	$(3,637)	$—	$(37,481)	$(3,666)

(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 nine months ended Sept. 30, 2015 included $0.4 million and $0.5 million, respectively, of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Losses for the nine months ended Sept. 30, 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 nine months ended Sept. 30, 2015 and nine 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 nine months ended Sept. 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.

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 Sept. 30, 2015, three of Xcel Energy’s 10 most significant counterparties for these activities, comprising $24.7 million or 10 percent of this credit exposure, had investment grade credit ratings from Standard & Poor’s Ratings Services, Moody’s Investor Services or Fitch Ratings. Five of the 10 most significant counterparties, comprising $61.1 million or 26 percent of this credit exposure, were not rated by these external agencies, but based on Xcel Energy’s internal analysis, had credit quality consistent with investment grade. The remaining two most significant counterparties, comprising $11.5 million or 5 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external and internal analysis. All 10 of these significant counterparties are RTOs, municipal or cooperative electric entities or other utilities.

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Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. If the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade, derivative instruments reflected in a $8.9 million gross liability position on the consolidated balance sheet at Sept. 30, 2015 would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle applicable outstanding contracts, including other contracts subject to master netting agreements, which would have resulted in payments of $0.1 million. At 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 Sept. 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 Sept. 30, 2015:

	Sept. 30, 2015					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$—	$9,140	$4,307	$13,447	$(5,150)	$8,297
Electric commodity	—	—	34,715	34,715	(6,361)	28,354
Natural gas commodity	—	3,062	—	3,062	(1,690)	1,372
Total current derivative assets	$—	$12,202	$39,022	$51,224	$(13,201)	38,023
PPAs [a]						10,087
Current derivative instruments						$48,110
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$29,523	$—	$29,523	$(7,411)	$22,112
Total noncurrent derivative assets	$—	$29,523	$—	$29,523	$(7,411)	22,112
PPAs [a]						32,631
Noncurrent derivative instruments						$54,743

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(Thousands of Dollars)	Sept. 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	$—	$156	$—	$156	$—	$156
Other derivative instruments:						
Commodity trading	—	6,461	1,478	7,939	(5,592)	2,347
Electric commodity	—	—	6,361	6,361	(6,361)	—
Natural gas commodity	—	2,777	—	2,777	(1,690)	1,087
Other commodity	—	844	—	844	—	844
Total current derivative liabilities	$—	$10,238	$7,839	$18,077	$(13,643)	4,434
PPAs [(a)]						22,869
Current derivative instruments						$27,303
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$36	$—	$36	$—	$36
Other derivative instruments:						
Commodity trading	—	20,789	—	20,789	(11,097)	9,692
Other commodity	—	18	—	18	—	18
Total noncurrent derivative liabilities	$—	$20,843	$—	$20,843	$(11,097)	9,746
PPAs [(a)]						163,842
Noncurrent derivative instruments						$173,588

(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 Sept. 30, 2015. At Sept. 30, 2015, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $4.1 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 nine months ended Sept. 30, 2015 and 2014:

(Thousands of Dollars)	Three Months Ended Sept. 30 2015	2014
Balance at July 1	$46,826	$105,394
Purchases	486	5,588
Settlements	(20,216)	(20,032)
Transfers out of Level 3	—	(1,093)

Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	121	1,480
Gains (losses) recognized as regulatory assets and liabilities	3,966	(17,705)
Balance at Sept. 30	$31,183	$73,632

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(Thousands of Dollars)	Nine Months Ended Sept. 30 2015	2014
Balance at Jan. 1	$56,155	$41,660
Purchases	63,724	126,752
Settlements	(57,462)	(107,451)
Transfers out of Level 3	—	(1,093)
Net transactions recorded during the period:		
Gains recognized in earnings [a]	1,401	8,917
(Losses) gains recognized as regulatory assets and liabilities	(32,635)	4,847
Balance at Sept. 30	$31,183	$73,632

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

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2015. The transfer of amounts from Level 3 to Level 2 in the three and nine months ended Sept. 30, 2014 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.

Fair Value of Long-Term Debt

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

(Thousands of Dollars)	Sept. 30, 2015 Carrying Amount	Fair Value	Dec. 31, 2014 Carrying Amount	Fair Value
Long-term debt, including current portion	$13,148,225	$14,304,149	$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 Sept. 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:

(Thousands of Dollars)	Three Months Ended Sept. 30 2015	2014	Nine Months Ended Sept. 30 2015	2014
Interest income	$312	$1,139	$4,939	$6,324
Other nonoperating income	625	682	2,387	3,042
Insurance policy income (expense)	689	(417)	(1,578)	(4,663)
Other nonoperating expense	—	—	—	(16)
Other income, net	$1,626	$1,404	$5,748	$4,687

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.

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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 $80.3 million and $83.1 million as of Sept. 30, 2015 and Dec. 31, 2014, respectively, included in the regulated natural gas utility segment.

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

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

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2015					
Operating revenues from external customers	$2,667,480	$216,019	$17,813	$—	$2,901,312
Intersegment revenues	392	293	—	(685)	—
Total revenues	$2,667,872	$216,312	$17,813	$(685)	$2,901,312
Net income (loss)	$437,978	$(4,176)	$(7,339)	$—	$426,463

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2014					
Operating revenues from external customers	$2,616,351	$236,649	$16,807	$—	$2,869,807
Intersegment revenues	472	597	—	(1,069)	—
Total revenues	$2,616,823	$237,246	$16,807	$(1,069)	$2,869,807
Net income	$360,656	$3,996	$3,930	$—	$368,582

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2015					
Operating revenues from external customers [(a)]	$7,105,803	$1,216,146	$56,716	$—	$8,378,665

Intersegment revenues	1,142	1,141	—	(2,283)	—
Total revenues	$7,106,945	$1,217,287	$56,716	$(2,283)	$8,378,665
Net income (loss)	$733,954 [a]	$72,617	$(31,111)	$—	$775,460
(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2014					
Operating revenues from external customers	$7,215,699	$1,485,464	$56,344	$—	$8,757,507
Intersegment revenues	1,262	4,967	—	(6,229)	—
Total revenues	$7,216,961	$1,490,431	$56,344	$(6,229)	$8,757,507
Net income (loss)	$731,766	$96,629	$(3,428)	$—	$824,967

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

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11. Earnings Per Share

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

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards in share-based compensation arrangements.

Common stock equivalents causing dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards and time based employer matching contributions to certain 401(k) plan participants.

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

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 Sept. 30, 2015			Three Months Ended Sept. 30, 2014		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$426,463	—	—	$368,582	—	—
Basic EPS:						
Earnings available to common shareholders	426,463	508,031	$0.84	368,582	506,082	$0.73
Effect of dilutive securities:						
Time based equity awards	—	396	—	—	283	—
Diluted EPS:						
Earnings available to common shareholders	$426,463	508,427	$0.84	$368,582	506,365	$0.73

	Nine Months Ended Sept. 30, 2015			Nine Months Ended Sept. 30, 2014		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$775,460		—	$824,967	—	—

Basic EPS:						
Earnings available to common shareholders	775,460	507,585	$1.53	824,967	502,983	$1.64
Effect of dilutive securities:						
Time based equity awards	—	391	—	—	230	—
Diluted EPS:						
Earnings available to common shareholders	$775,460	507,976	$1.53	$824,967	503,213	$1.64

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12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2015	2014	2015	2014
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$24,828	$22,086	$529	$864
Interest cost	37,131	39,155	6,324	8,507
Expected return on plan assets	(53,473)	(51,801)	(6,650)	(8,489)
Amortization of prior service credit	(451)	(437)	(2,672)	(2,672)
Amortization of net loss	31,288	29,191	1,351	2,935
Net periodic benefit cost (credit)	39,323	38,194	(1,118)	1,145
Costs not recognized due to the effects of regulation	(7,016)	(6,605)	—	—
Net benefit cost (credit) recognized for financial reporting	$32,307	$31,589	$(1,118)	$1,145

	Nine Months Ended Sept. 30			
	2015	2014	2015	2014
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$74,484	$66,257	$1,587	$2,592
Interest cost	111,393	117,465	18,972	25,521
Expected return on plan assets	(160,418)	(155,403)	(19,950)	(25,466)
Amortization of prior service credit	(1,353)	(1,310)	(8,015)	(8,016)
Amortization of net loss	93,864	87,572	4,053	8,805
Net periodic benefit cost (credit)	117,970	114,581	(3,353)	3,436
Costs not recognized due to the effects of regulation	(22,035)	(20,261)	—	—
Net benefit cost (credit) recognized for financial reporting	$95,935	$94,320	$(3,353)	$3,436

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 nine months ended Sept. 30, 2015 and 2014 were as follows:

	Three Months Ended Sept. 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 July 1	$(56,436)	$112	$(48,862)	$(105,186)
Other comprehensive loss before reclassifications	(42)	(1)	—	(43)
Losses reclassified from net accumulated other comprehensive loss	706	—	884	1,590
Net current period other comprehensive income (loss)	664	(1)	884	1,547
	$(55,772)	$111	$(47,978)	$(103,639)

Accumulated other comprehensive (loss) income at Sept. 30	41

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(Thousands of Dollars)	Three Months Ended Sept. 30, 2014 Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at July 1	$(58,610)	$115	$(44,871)	$(103,366)
Other comprehensive (loss) income before reclassifications	(42)	2	—	(40)
Losses reclassified from net accumulated other comprehensive loss	558	—	847	1,405
Net current period other comprehensive income	516	2	847	1,365
Accumulated other comprehensive (loss) income at Sept. 30	$(58,094)	$117	$(44,024)	$(102,001)

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2015 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 (loss) income before reclassifications	(35)	1	—	(34)
Losses reclassified from net accumulated other comprehensive loss	1,891	—	2,643	4,534
Net current period other comprehensive income	1,856	1	2,643	4,500
Accumulated other comprehensive (loss) income at Sept. 30	$(55,772)	$111	$(47,978)	$(103,639)

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2014 Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$(59,753)	$77	$(46,599)	$(106,275)
Other comprehensive (loss) income before reclassifications	(34)	40	—	6
Losses reclassified from net accumulated other comprehensive loss	1,693	—	2,575	4,268
Net current period other comprehensive income	1,659	40	2,575	4,274
Accumulated other comprehensive (loss) income at Sept. 30	$(58,094)	$117	$(44,024)	$(102,001)

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

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended Sept. 30, 2015		Three Months Ended Sept. 30, 2014	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$1,118	(a)	$967	(a)
Vehicle fuel derivatives	34	(b)	(16	) (b)
Total, pre-tax	1,152		951	
Tax benefit	(446	)	(393	)
Total, net of tax	706		558	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	1,532	(c)	1,500	(c)
Prior service credit	(89	) (c)	(86	) (c)
Total, pre-tax	1,443		1,414	
Tax benefit	(559	)	(567	)
Total, net of tax	884		847	
Total amounts reclassified, net of tax	$1,590		$1,405	

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(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Nine Months Ended Sept. 30, 2015		Nine Months Ended Sept. 30, 2014	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$3,013	[a]	$2,869	[a]
Vehicle fuel derivatives	88	[b]	(61	) [b]
Total, pre-tax	3,101		2,808	
Tax benefit	(1,210	)	(1,115	)
Total, net of tax	1,891		1,693	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	4,600	[c]	4,499	[c]
Prior service (credit) cost	(268	) [c]	(258	) [c]
Total, pre-tax	4,332		4,241	
Tax benefit	(1,689	)	(1,666	)
Total, net of tax	2,643		2,575	
Total amounts reclassified, net of tax	$4,534		$4,268	

[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 herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2015 and 2016 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," "plan," "project," "possible," "po and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly Reports on Form 10-Q and in other securities filings (including Xcel Energy's Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2014 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2015 and June 30, 2015), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) 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 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; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability of cost of capital; and employee work force factors.

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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 Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	2015	2014	2015	2014
PSCo	$0.34	$0.30	$0.75	$0.72
NSP-Minnesota	0.35	0.27	0.65	0.63
SPS	0.12	0.13	0.21	0.23
NSP-Wisconsin	0.05	0.04	0.13	0.11
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.03
Regulated utility	0.87	0.75	1.77	1.72
Xcel Energy Inc. and other	(0.03)	(0.02)	(0.08)	(0.08)
Ongoing diluted EPS	0.84	0.73	1.69	1.64
Loss on Monticello LCM/EPU project	—	—	(0.16)	—
GAAP diluted EPS	$0.84	$0.73	$1.53	$1.64

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 nine months ended Sept. 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 allowed 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 in the first quarter of 2015. See Note 5 to the consolidated financial statements for further discussion.

Summary of Ongoing Earnings

Xcel Energy — Xcel Energy's ongoing earnings increased $0.11 for the third quarter of 2015 and $0.05 per share year-to-date, which excludes an adjustment for a charge related to the NSP-Minnesota Monticello LCM/EPU project. Electric and gas margins rose in the third quarter of 2015 primarily due to an increase in retail electric rates, non-fuel riders, the impact of favorable weather and a lower earnings test refund in Colorado. These positive factors were partially offset by higher depreciation and interest charges, lower AFUDC and increased property taxes.

PSCo — PSCo's ongoing earnings increased $0.04 per share for the third quarter of 2015 and $0.03 year-to-date. Higher revenue primarily due to the CACJA rider (partially offset by an electric base rate decrease), lower estimated electric earnings test refunds and the impact of favorable weather were partially offset by lower AFUDC, higher property taxes, depreciation and O&M expenses.

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NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.08 per share for the third quarter of 2015 and $0.02 year-to-date. Revenues increased primarily due to electric rate cases in Minnesota, North Dakota and South Dakota and were partially offset by higher depreciation, higher O&M expenses, lower gas margins, higher interest charges, unfavorable weather and weather-normalized sales decline.

SPS — SPS' ongoing earnings decreased $0.01 per share for the third quarter of 2015 and $0.02 year-to-date. Higher electric rates in Texas were more than offset by higher O&M expenses, increased depreciation, lower AFUDC and higher interest charges and unfavorable weather.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings per share increased $0.01 for the third quarter of 2015 and $0.02 year-to-date. Higher electric margins, primarily due to an electric rate increase and weather-normalized sales growth and lower O&M expenses were partially 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 Sept. 30	Nine Months Ended Sept. 30
2014 GAAP and ongoing diluted EPS	$0.73	$1.64
Components of change — 2015 vs. 2014		
Higher electric margins	0.14	0.25
Lower conservation and DSM program expenses (offset by lower revenues)	0.02	0.07
Higher depreciation and amortization	(0.03)	(0.09)
Lower AFUDC — equity	(0.02)	(0.06)
Higher O&M expenses	—	(0.04)
Higher taxes (other than income taxes)	(0.01)	(0.04)
Higher ETR	(0.01)	(0.03)
Higher interest charges	(0.01)	(0.02)
Dilution from equity issued through the direct stock purchase plan and benefit plans	—	(0.02)
Higher natural gas margins	0.02	—
Other, net	0.01	0.03
2015 ongoing diluted EPS	0.84	1.69
Loss on Monticello LCM/EPU project	—	(0.16)
2015 GAAP diluted EPS	$0.84	$1.53

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2015	2014	2015	2014
GAAP income (loss) by segment				
Regulated electric income	$438.0	$360.7	$734.0	$731.8
Regulated natural gas (loss) income	(4.2)	4.0	72.6	96.6
Other income [(a)]	7.7	15.2	10.0	35.4
Xcel Energy Inc. and other [(a)]	(15.0)	(11.3)	(41.1)	(38.8)
Total net income	$426.5	$368.6	$775.5	$825.0

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Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30 2015	Three Months Ended Sept. 30 2014	Nine Months Ended Sept. 30 2015	Nine Months Ended Sept. 30 2014
GAAP earnings (loss) by segment				
Regulated electric	$0.86	$0.71	$1.45	$1.46
Regulated natural gas	(0.01)	0.01	0.14	0.19
Other [(a)]	0.02	0.03	0.02	0.07
Xcel Energy Inc. and other [(a)]	(0.03)	(0.02)	(0.08)	(0.08)
Total diluted EPS	$0.84	$0.73	$1.53	$1.64

[(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 Sept. 30			Nine Months Ended Sept. 30		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
HDD	(57.9)%	(11.2)%	(54.8)%	(4.2)%	11.5 %	(14.4)%
CDD	15.1	(4.0)	20.0	5.4	(2.5)	8.3
THI	4.3	(17.3)	29.2	(1.6)	(11.2)	13.7

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

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
Retail electric	$0.010	$(0.024)	$0.034	$(0.004)	$0.010	$(0.014)
Firm natural gas	(0.002)	—	(0.002)	(0.007)	0.018	(0.025)
Total	$0.008	$(0.024)	$0.032	$(0.011)	$0.028	$(0.039)

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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 Sept. 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Actual					
Electric residential [(a)]	4.3 %	4.2 %	3.3 %	6.2 %	6.6 %
Electric commercial and industrial	1.1	1.3	0.8	1.9	1.0
Total retail electric sales	1.9	2.2	1.4	3.0	1.4
Firm natural gas sales	(5.7)	(7.9)	(1.4)	(3.1)	N/A

	Three Months Ended Sept. 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Weather-normalized					
Electric residential [(a)]	0.6 %	1.5 %	(0.2)%	(0.6)%	1.3 %
Electric commercial and industrial	—	(0.7)	0.2	0.2	0.4
Total retail electric sales	0.1	—	—	(0.1)	0.5
Firm natural gas sales	(0.3)	(1.3)	1.6	0.8	N/A

	Nine Months Ended Sept. 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Actual					
Electric residential [(a)]	(1.4)%	0.5 %	(2.9)%	(4.6)%	(0.3)%
Electric commercial and industrial	—	—	(0.3)	1.3	—
Total retail electric sales	(0.5)	0.2	(1.1)	(0.4)	(0.2)
Firm natural gas sales	(11.2)	(9.0)	(14.7)	(12.5)	N/A

	Nine Months Ended Sept. 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Weather-normalized					
Electric residential [(a)]	(0.6)%	(0.1)%	(1.2)%	(2.5)%	1.0 %
Electric commercial and industrial	—	(0.7)	0.1	1.5	0.3
Total retail electric sales	(0.2)	(0.5)	(0.3)	0.3	0.3
Firm natural gas sales	(1.8)	(2.3)	(1.1)	0.1	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 reduced sales to certain large manufacturing customers and/or those that support the fracking industry. 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 the remaining large and small customers in various industries. The residential decrease was due to less use per customer, partially offset by an increase in 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 Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2015	2014	2015	2014
Electric revenues	$2,667	$2,616	$7,106	$7,216
Electric fuel and purchased power	(1,015)	(1,080)	(2,870)	(3,188)
Electric margin	$1,652	$1,536	$4,236	$4,028

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

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2015 vs. 2014	Nine Months Ended Sept. 30 2015 vs. 2014
Fuel and purchased power cost recovery	$(90)	$(345)
Conservation and DSM program revenues (offset by expenses)	(17)	(46)
Estimated impact of weather	26	(11)
Non-fuel riders (a) (b)	20	87
Retail rate increases (b)	31	80
PSCo earnings test refund	26	61
Transmission revenue	36	58
Trading	10	3
Other, net	9	3
Total increase (decrease) in electric revenues	$51	$(110)

Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2015 vs. 2014	Nine Months Ended Sept. 30 2015 vs. 2014
Non-fuel riders (a) (b)	$20	$87
Retail rate increases (b)	31	80
PSCo earnings test refund	26	61
Transmission revenue, net of costs	22	28
Conservation and DSM program revenues (offset by expenses)	(17)	(46)
Estimated impact of weather	26	(11)
Other, net	8	9
Total increase in electric margin	$116	$208

[(a)] Primarily related to the new CACJA rider in Colorado ($23 million and $74 million, respectively).
Increase due to rate proceedings in Minnesota, South Dakota, North Dakota, Texas, New Mexico and Wisconsin.
[(b)] 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 Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2015	2014	2015	2014
Natural gas revenues	$216	$237	$1,216	$1,485
Cost of natural gas sold and transported	(66)	(99)	(665)	(934)
Natural gas margin	$150	$138	$551	$551

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2015 vs. 2014	Nine Months Ended Sept. 30 2015 vs. 2014
Purchased natural gas adjustment clause recovery	$(28)	$(262)
Estimated impact of weather	(1)	(20)
Conservation and DSM program revenues (offset by expenses)	—	(11)
Non-fuel riders, partially offset by expenses	7	25
Other, net	1	(1)
Total decrease in natural gas revenues	$(21)	$(269)

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2015 vs. 2014	Nine Months Ended Sept. 30 2015 vs. 2014
Non-fuel riders, partially offset by expenses	$7	$25
Gas transport - Cherokee pipeline	2	4
Estimated impact of weather	(1)	(20)
Conservation and DSM program revenues (offset by expenses)	—	(11)
Other, net	4	2
Total increase in natural gas margin	$12	$—

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $2.4 million, or 0.4 percent, for the third quarter of 2015 and increased $32.0 million, or 1.9 percent, for the nine months ended Sept. 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 as well as an increase in contractor costs.

(Millions of Dollars)	Three Months Ended Sept.	Nine Months Ended Sept.

	30 2015 vs. 2014	30 2015 vs. 2014
Plant generation costs	$(8)	$13
Labor and contract labor	5	11
Electric and natural gas distribution expenses	7	7
Nuclear plant operations	(11)	(7)
Other, net	5	8
Total (decrease) increase in O&M expenses	$(2)	$32

For the third quarter of 2015, O&M expenses decreased due to the following:

- Plant generation costs were related to the timing of overhauls and discovery work; and
- Nuclear expense decreases were primarily due to reduced costs driven by operational initiatives and efficiencies.

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Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased $17.9 million for the third quarter of 2015 and $58.3 million for the nine months ended Sept. 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 $24.7 million, or 9.7 percent, for the third quarter of 2015 and $71.2 million, or 9.4 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 DOE settlement.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $5.1 million, or 4.3 percent, for the third quarter of 2015 and $30.5 million, or 8.5 percent, for the nine months ended Sept. 30, 2015. Increases were due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC decreased $10.8 million for the third quarter of 2015 and $38.4 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 $9.3 million, or 6.5 percent, for the third quarter of 2015 and $20.0 million, or 4.7 percent, for the nine months ended Sept. 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 $43.1 million for the third quarter of 2015 compared with the same period in 2014. The increase was primarily due to higher pretax earnings and decreased permanent plant-related adjustments in 2015. The ETR was 35.9 percent for the third quarter of 2015 compared with 34.7 percent for the same period in 2014. The higher ETR for 2015 was primarily due to the plant-related adjustments referenced above.

Income tax expense decreased $3.5 million for the first nine months of 2015 compared with the same period in 2014. The decrease was primarily due to lower pretax earnings, partially offset by decreased permanent plant-related adjustments and the successful resolution of a 2010-2011 IRS audit issue in 2014. The ETR was 35.8 percent for the first nine months of 2015, compared to 34.6 percent for the first nine 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 Reports on Form 10-Q for the quarterly periods ended March 31, 2015 and June 30, 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 — In September 2015, NSP-Minnesota began construction of the Courtenay wind farm, a 200 MW NSP-Minnesota owned project in North Dakota. In May 2015, NSP-Minnesota filed for expedited regulatory approval in Minnesota and North Dakota. In July and August 2015, the MPUC and NDPSC, respectively, approved the Courtenay wind farm with recovery up to $300 million of capital costs. The project costs were requested to be recovered through the Minnesota renewable energy standard rider and the North Dakota renewable energy rider.

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NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Integrated Resource Plan (the Plan) with the MPUC.

On Oct. 2, 2015, NSP-Minnesota filed revisions to the Plan. The revised proposal addressed stakeholder recommendations as well as the final Clean Power Plan (CPP) recently issued by the EPA. The revised Plan is based on four primary elements: (1) accelerate the transition from coal energy to renewables, (2) preserve regional system reliability, (3) pursue energy efficiency gains and grid modernization, and (4) ensure customer benefits. The provisions included in the Plan would allow for a 60 percent reduction in carbon emissions from 2005 levels by 2030 and will result in 63 percent of NSP System energy being carbon-free by 2030. Specific terms of the proposal include:

- The addition of 800 MW of wind and 400 MW of utility scale solar to the pre-2020 time-frame;
- The addition of 1000 MW wind and 1000 MW utility scale solar between 2020-2030;
- The retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026;
- The addition of a 230 MW (approximate capacity, actual size to be determined) natural gas combustion turbine in North Dakota by 2025;
- Replacement of Sherco coal generation with a 780 MW (approximate capacity, actual size to be determined) natural gas combined cycle unit at the Sherco site no later than 2026; and
- Operation of the Monticello and PI nuclear plants through their current license periods in the early 2030's.

NSP-Minnesota believes this will provide substantial opportunities for the ownership of replacement and renewable generation. The Plan is currently being reviewed by the MPUC.

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 Sept. 30, 2015, Xcel Energy has invested $975.5 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. The first 345 KV segment was energized in September 2015 and stretches from the North Rochester Substation in Minn. to the Briggs Road Substation in Wis.
- 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 project was placed in service in September 2012.
- Big Stone South to Brookings County, S.D. 345 KV transmission line — Construction on the line began in September 2015, with completion anticipated 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 additional 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 Department of Commerce 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 August 2015, the MPUC issued an order regarding the Solar*Rewards Community program, limiting 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. In October 2015, the MPUC denied requests for reconsideration of the project size limitation.

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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 MYPs and more certainty regarding recovery of costs and the impact to customers. This bill provides:

- Increased flexibility for utilities to submit a 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, such as in a resource plan; 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, 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. In March 2015, Monticello was upgraded from Column 3 to Column 2 (regulatory response) based on the results of an NRC inspection in late 2014 to close out the flood control finding. The NRC conducted an inspection on the security finding in July 2015. Based on the results of the NRC inspection, Monticello was upgraded to Column 1 on Oct. 1, 2015.

As of Oct. 1, 2015, Monticello and PI Units 1 and 2 were in Column 1 (licensee response) with all green performance indicators and no greater than green findings or violations. Plants in Column 1 are subject to only a pre-defined set of basic NRC inspections.

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 co-owners, Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

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 circuit 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 is expected to 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.

2015 Electric Fuel Cost Recovery — NSP-Wisconsin’s electric fuel costs for the nine months ended Sept. 30, 2015 were lower than authorized in rates and outside the two percent annual tolerance band established in the Wisconsin fuel cost recovery rules, primarily due to lower load as a result of mild weather, lower natural gas prices and lower purchased power prices in the MISO market. Under the fuel cost recovery rules, NSP-Wisconsin may retain the amount of over-recovery up to two percent of authorized annual fuel costs, or approximately $3.5 million. However, NSP-Wisconsin must defer the amount of over-recovery in excess of the two percent annual tolerance band for future refund to customers. Accordingly, NSP-Wisconsin recorded a deferral of approximately $5.9 million through Sept. 30, 2015. The amount of the deferral could increase or decrease based on actual fuel costs incurred for the remainder of the year. In the first quarter of 2016, NSP-Wisconsin will file a reconciliation of 2015 fuel costs with the PSCW. The amount of any potential refund is subject to review and approval by the PSCW, which is not expected until mid-2016.

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PSCo

Net Metering Standard — PSCo had previously proposed to track and quantify the system costs that are not avoided by distributed solar generation, which PSCo has defined as a "net metering incentive," for purposes of equitably recovering costs between customers. The CPUC assigned the net metering issue to its own docket and conducted a series of panel discussions to gain a better understanding of net metering issues. In the third quarter, the CPUC closed the net metering docket, concluding that they would not make any changes to the net metering policies. The decision does not preclude the PSCo from filing changes to the PSCo's net metering practices in the future.

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 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.

In July 2015, Boulder filed an application with the CPUC requesting approval of Boulder's proposed separation plan, seeking to take certain distribution assets of PSCo outside of the city limits but allowing PSCo to bill the customers for service. In August 2015, PSCo brought a Motion to Dismiss arguing Boulder's request was not permissible under

Colorado law. The matter is now pending before the CPUC.

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. In August 2015, the CPUC granted the application for the upgrade.

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SPS

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

Summary of Recent Federal Regulatory Developments

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

FERC Order, New ROE Policy — In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In March, 2015, FERC upheld the new ROE methodology and denied rehearing. 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 the litigated ROE complaint proceedings until 2016. See Note 5 to the consolidated financial statements for discussion of the SPS Wholesale Rate Complaints 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.

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At Sept. 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	$2,679	$7,119	$1,261	$356	$11,415
NSP-Minnesota	2	2,573	—	—	—	2,573
		$5,252	$7,119	$1,261	$356	$13,988

	Options					
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	2	$254	$—	$—	$—	$254

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

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

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	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	(4,400)	(9,225)
Commodity trading contract additions and changes during period	(3,169)	2,676
Fair value of commodity trading net contract assets outstanding at Sept. 30	$14,242	$23,965

At Sept. 30, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.5 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.5 million. At Sept. 30, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1.4 million.

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

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

(Millions of Dollars)	Three Months Ended Sept. 30	VaR Limit	Average	High	Low
2015	$0.17	$3.00	$0.23	$0.63	$0.10
2014	0.60	3.00	0.50	4.06	0.13

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 13 percent of its 2015 and approximately 46 percent of its 2016 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 35 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.

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

At Sept. 30, 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 $0.8 million and $7.1 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Sept. 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 Sept. 30, 2015, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $4.8 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $11.7 million. At Sept. 30, 2014, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $35.2 million, while a decrease in prices of 10 percent would have resulted in a decrease in credit exposure of $14.1 million.

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

Fair Value Measurements

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

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Sept. 30, 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 Sept. 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 2.0 percent and 20.1 percent of total assets and liabilities, respectively, measured at fair value at Sept. 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 $38.8 million and $7.8 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2015.

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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 Sept. 30, 2015. There were no Level 3 options held at Sept. 30, 2015.

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 $218 million in the nuclear decommissioning fund at Sept. 30, 2015 (approximately 11.0 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

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2015	2014
Cash provided by operating activities	$2,490	$2,004

Net cash provided by operating activities increased $486 million for the nine months ended Sept. 30, 2015 compared with the nine months ended Sept. 30, 2014. The increase was primarily due to higher electric cost recovery in 2015, timing of customer refunds in 2014, solar garden deposits received in 2015 and income tax refunds received in 2015 compared to taxes paid in 2014.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2015	2014
Cash used in investing activities	$(2,139)	$(2,235)

Net cash used in investing activities decreased $96 million for the nine months ended Sept. 30, 2015 compared with the nine months ended Sept. 30, 2014. The decrease was primarily attributable to higher capital expenditures in 2014 related to CACJA initiatives, including the construction of a natural gas fired combined cycle unit at Cherokee generating station and the addition of emissions controls at Pawnee station, as well as natural gas pipeline construction projects and the impact of higher insurance proceeds related to Sherco Unit 3 received in 2015.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2015	2014
Cash (used in) provided by financing activities	$(26)	$261

Net cash used in financing activities was $26 million for the nine months ended Sept. 30, 2015 compared with net cash provided by financing activities of $261 million for the nine months ended Sept. 30, 2014, or a change of $287 million. The difference was primarily due to higher repayments of short-term debt and fewer issuances of common stock in 2015, partially offset by higher debt issuances in 2015.

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 law 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.

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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 law 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.

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 Sept. 30, 2015, SPS had a $10 million letter of credit posted with SPP, which was a reduction from the previous requirement of $36 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 Sept. 30, 2015, approximately $330.2 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 Oct. 26, 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	$—	$1,000	$6	$1,006
PSCo	700	4	696	1	697
NSP-Minnesota	500	23	477	156	633
SPS	400	10	390	1	391
NSP-Wisconsin	150	15	135	1	136
Total	$2,750	$52	$2,698	$165	$2,863

(a) These credit facilities expire in October 2019.

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

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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.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2015	Twelve Months Ended Dec. 31, 2014
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	64	1,020
Average amount outstanding	272	841
Maximum amount outstanding	478	1,200
Weighted average interest rate, computed on a daily basis	0.46 %	0.33 %
Weighted average interest rate at period end	0.38	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;
- In June, NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024;
- In August, NSP-Minnesota issued $300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and $300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045; and
- In September, SPS issued $200 million of 3.3 percent first mortgage bonds due June 15, 2024.

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

Financing Plans — During 2016, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately $600 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $250 million of first mortgage bonds; and

- SPS plans to issue approximately $350 million of first mortgage bonds.

Dividend Reinvestment and Stock Purchase Plan and Stock Compensation Settlements — In October 2015, the Xcel Energy Inc. Board of Directors authorized open market purchases by the plan administrator as the source of shares for the dividend reinvestment program as well as market purchases of up to 3.0 million shares for stock compensation plan settlements.

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Off-Balance-Sheet Arrangements

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

Earnings Guidance

Xcel Energy's revised 2015 ongoing earnings guidance to $2.05 to $2.15 per share, compared with the previous issued guidance of $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 be relatively flat.
- Weather-normalized retail firm natural gas sales are projected to decline approximately 2 percent.
- Capital rider revenue is projected to increase by $150 million to $160 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 $110 million to $120 million over 2014 levels. The change in the depreciation assumption reflects an adjustment for eliminations and will not have any impact on earnings.
- Property taxes are projected to increase approximately $50 million to $60 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.

Xcel Energy's 2016 ongoing earnings guidance is $2.12 to $2.27 per share. Key assumptions related to 2016 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings, including the implementation of interim rates in Minnesota consistent with historical precedent.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 0.5 percent to 1.0 percent.
- Weather normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase by $70 million to $80 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2015 levels.
- Depreciation expense is projected to increase approximately $200 million over 2015 levels.
- Property taxes are projected to increase approximately $40 million to $50 million over 2015 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2015 levels.
- AFUDC — equity is projected to decline approximately $5 million to $10 million from 2015 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 509 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 Sept. 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.

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.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended Sept. 30, 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
July 1, 2015 — July 31, 2015	—	$—	—	—
Aug. 1, 2015 — Aug. 31, 2015	—	—	—	—
Sept. 1, 2015 — Sept. 30, 2015	—	—	—	—
Total	—		—	—

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
4.01*	Supplemental Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300,000,000 principal amount of 2.20 percent First Mortgage Bonds, Series due Aug. 15, 2020 and $300,000,000 principal amount of 4.00 percent First Mortgage Bonds, Series due Aug. 15, 2045 (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated Aug. 11, 2015 (file no. 001-31387)).
31.01	Principal Executive Officer’s certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer’s certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.

101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 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.
Oct. 30, 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)