Section 1: 10-Q (10-Q)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended Sept. 30, 2016
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. ☒ 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). ☒ 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 ☒	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 ☒ 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 24, 2016
Common Stock, $2.50 par value	507,952,795 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).

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	
	2016	2015	2016	2015
Operating revenues				
Electric	$ 2,799,964	$ 2,667,480	$ 7,209,225	$ 7,105,803
Natural gas	221,956	216,019	1,046,544	1,216,146
Other	18,227	17,813	56,500	56,716
Total operating revenues	3,040,147	2,901,312	8,312,269	8,378,665
Operating expenses				
Electric fuel and purchased power	1,037,263	1,014,726	2,755,083	2,869,563
Cost of natural gas sold and transported	67,566	66,071	469,754	665,109
Cost of sales — other	8,648	8,203	25,225	26,416
Operating and maintenance expenses	590,009	565,984	1,764,397	1,746,093
Conservation and demand side management program expenses	63,914	57,314	177,266	165,260
Depreciation and amortization	328,503	280,121	971,057	827,821
Taxes (other than income taxes)	117,190	123,081	400,982	389,438
Loss on Monticello life cycle management/extended power uprate project	—	—	—	129,463
Total operating expenses	2,213,093	2,115,500	6,563,764	6,819,163
Operating income	827,054	785,812	1,748,505	1,559,502
Other income, net	578	1,626	6,388	5,748
Equity earnings of unconsolidated subsidiaries	9,701	8,162	32,500	24,360
Allowance for funds used during construction — equity	17,199	15,427	45,042	40,728
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,060 $6,260, $19,026 and $17,819, respectively	165,857	152,566	485,280	441,728
Allowance for funds used during construction — debt	(7,532)	(7,031)	(20,206)	(19,340)
Total interest charges and financing costs	158,325	145,535	465,074	422,388
Income before income taxes	696,207	665,492	1,367,361	1,207,950
Income taxes	238,412	239,029	471,459	432,490
Net income	$ 457,795	$ 426,463	$ 895,902	$ 775,460
Weighted average common shares outstanding:				
Basic	508,941	508,031	508,840	507,585
Diluted	509,566	508,427	509,396	507,976
Earnings per average common share:				
Basic	$ 0.90	$ 0.84	$ 1.76	$ 1.53
Diluted	0.90	0.84	1.76	1.53
Cash dividends declared per common share	$ 0.34	$ 0.32	$ 1.02	$ 0.96

See Notes to Consolidated Financial Statements

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2016	2015	2016	2015
Net income	$ 457,795	$ 426,463	$ 895,902	$ 775,460
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $536, $559, $1,635 and $1,689, respectively	878	884	1,954	2,643
Derivative instruments:				
Net fair value (decrease) increase, net of tax of $(2), $(28), $3 and $(24), respectively	(4)	(42)	4	(35)
Reclassification of losses to net income, net of tax of $588, $446, $1,786 and $1,210, respectively	960	706	2,834	1,891
	956	664	2,838	1,856
Marketable securities:				
Net fair value (decrease) increase, net of tax of $0, $0, $0 and $1, respectively	—	(1)	—	1
Other comprehensive income	1,834	1,547	4,792	4,500
Comprehensive income	$ 459,629	$ 428,010	$ 900,694	$ 779,960

See Notes to Consolidated Financial Statements

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

	Nine Months Ended Sept. 30	
	2016	2015
Operating activities		
Net income	$ 895,902	$ 775,460
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	982,682	841,360
Conservation and demand side management program amortization	3,089	4,063
Nuclear fuel amortization	89,475	82,627
Deferred income taxes	479,100	429,091
Amortization of investment tax credits	(3,920)	(4,151)
Allowance for equity funds used during construction	(45,042)	(40,728)
Equity earnings of unconsolidated subsidiaries	(32,500)	(24,360)
Dividends from unconsolidated subsidiaries	34,502	29,434
Share-based compensation expense	29,872	29,765
Loss on Monticello life cycle management/extended power uprate project	—	129,463
Net realized and unrealized hedging and derivative transactions	3,307	18,808
Other	(266)	—
Changes in operating assets and liabilities:		
Accounts receivable	(29,585)	85,276
Accrued unbilled revenues	87,015	182,425
Inventories	(6,203)	(47,659)
Other current assets	80,566	72,445
Accounts payable	50,526	(116,137)
Net regulatory assets and liabilities	3,911	116,068
Other current liabilities	(76,011)	60,293
Pension and other employee benefit obligations	(96,350)	(82,013)
Change in other noncurrent assets	(11,815)	2,374
Change in other noncurrent liabilities	(25,401)	(53,982)
Net cash provided by operating activities	2,412,854	2,489,922
Investing activities		
Utility capital/construction expenditures	(2,186,483)	(2,186,369)
Proceeds from insurance recoveries	1,595	27,237
Allowance for equity funds used during construction	45,042	40,728
Purchases of investment securities	(390,031)	(773,260)
Proceeds from the sale of investment securities	327,378	753,924
Investments in WYCO Development LLC and other	(3,962)	(832)
Other, net	204	(676)
Net cash used in investing activities	(2,206,257)	(2,139,248)
Financing activities		
Repayments of short-term borrowings, net	(480,000)	(955,500)
Proceeds from issuance of long-term debt	1,632,642	1,627,190
Repayments of long-term debt	(580,167)	(250,644)
Proceeds from issuance of common stock	—	5,298
Purchase of common stock for settlement of equity awards	(2,810)	—
Dividends paid	(507,817)	(452,217)
Net cash provided by (used in) financing activities	61,848	(25,873)
Net change in cash and cash equivalents	268,445	324,801

Cash and cash equivalents at beginning of period		84,940		79,608
Cash and cash equivalents at end of period	$	353,385	$	404,409
Supplemental disclosure of cash flow information:				
Cash paid for interest (net of amounts capitalized)	$	(461,302)	$	(424,878)
Cash received for income taxes, net		61,245		57,632
Supplemental disclosure of non-cash investing and financing transactions:				
Property, plant and equipment additions in accounts payable	$	221,155	$	284,864
Issuance of common stock for reinvested dividends and equity awards		17,527		39,169

See Notes to Consolidated Financial Statements

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

	Sept. 30, 2016	Dec. 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$ 353,385	$ 84,940
Accounts receivable, net	754,248	724,606
Accrued unbilled revenues	567,852	654,867
Inventories	614,908	608,584
Regulatory assets	317,611	344,630
Derivative instruments	42,860	33,842
Deferred income taxes	195,303	140,219
Prepaid taxes	107,210	163,023
Prepayments and other	122,786	155,734
Total current assets	3,076,163	2,910,445
Property, plant and equipment, net	32,206,696	31,205,851
Other assets		
Nuclear decommissioning fund and other investments	2,048,455	1,902,995
Regulatory assets	2,874,351	2,858,741
Derivative instruments	51,369	51,083
Other	67,716	32,581
Total other assets	5,041,891	4,845,400
Total assets	$ 40,324,750	$ 38,961,696
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 709,567	$ 657,021
Short-term debt	366,000	846,000
Accounts payable	916,534	960,982
Regulatory liabilities	228,721	306,830
Taxes accrued	422,437	438,189
Accrued interest	155,005	166,829
Dividends payable	172,704	162,410
Derivative instruments	25,201	29,839
Other	457,803	490,197
Total current liabilities	3,453,972	4,058,297
Deferred credits and other liabilities		
Deferred income taxes	6,851,873	6,293,661
Deferred investment tax credits	64,499	68,419
Regulatory liabilities	1,367,557	1,332,889
Asset retirement obligations	2,703,396	2,608,562
Derivative instruments	154,650	168,311
Customer advances	216,978	228,999
Pension and employee benefit obligations	843,739	941,002
Other	277,561	261,756
Total deferred credits and other liabilities	12,480,253	11,903,599
Commitments and contingencies		

Capitalization		
Long-term debt	13,402,583	12,398,880
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 507,952,795 and 507,535,523 shares outstanding at Sept. 30, 2016 and Dec. 31, 2015, respectively	1,269,882	1,268,839
Additional paid in capital	5,898,896	5,889,106
Retained earnings	3,924,125	3,552,728
Accumulated other comprehensive loss	(104,961)	(109,753)
Total common stockholders' equity	10,987,942	10,600,920
Total liabilities and equity	$ 40,324,750	$ 38,961,696

See Notes to Consolidated Financial Statements

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

	Common Stock Issued				Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Other Comprehensive Loss	Common Stockholders' Equity
Three Months Ended Sept. 30, 2016 and 2015						
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
Balance at June 30, 2016	507,953	$ 1,269,882	$ 5,896,394	$ 3,643,653	$ (106,795)	$ 10,703,134
Net income				457,795		457,795
Other comprehensive income					1,834	1,834
Dividends declared on common stock				(173,786)		(173,786)
Issuances of common stock	48	120	—			120
Purchase of common stock for settlement of equity awards	(48)	(120)	(2,021)			(2,141)
Share-based compensation			4,523	(3,537)		986
Balance at Sept. 30, 2016	507,953	$ 1,269,882	$ 5,898,896	$ 3,924,125	$ (104,961)	$ 10,987,942

See Notes to Consolidated Financial Statements

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, 2016 and 2015						
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
Balance at Dec. 31, 2015	507,536	$ 1,268,839	$ 5,889,106	$ 3,552,728	$ (109,753)	$ 10,600,920
Net income				895,902		895,902
Other comprehensive income					4,792	4,792
Dividends declared on common stock				(520,968)		(520,968)
Issuances of common stock	486	1,216	15,110			16,326
Purchase of common stock for settlement of equity awards	(69)	(173)	(2,810)			(2,983)
Share-based compensation			(2,510)	(3,537)		(6,047)
Balance at Sept. 30, 2016	507,953	$ 1,269,882	$ 5,898,896	$ 3,924,125	$ (104,961)	$ 10,987,942

See Notes to Consolidated Financial Statements

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, 2016 and Dec. 31, 2015; 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, 2016 and 2015; and its cash flows for the nine months ended Sept. 30, 2016 and 2015. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2016 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, 2015 balance sheet information has been derived from the audited 2015 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2015. 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, 2015, filed with the SEC on Feb. 19, 2016. 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, 2015, 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. 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.

Presentation of Deferred Taxes — In November 2015, the FASB issued *Balance Sheet Classification of Deferred Taxes, Topic 740 (ASU No 2015-17)*, which eliminates the requirement to present deferred tax assets and liabilities as current and noncurrent on the balance sheet based on the classification of the related asset or liability, and instead requires classification of all deferred tax assets and liabilities as noncurrent. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2016, and early adoption is permitted. Other than the prescribed classification of all deferred tax assets and liabilities as noncurrent, Xcel Energy does not expect the implementation of ASU 2015-17 to have a material impact on its consolidated financial statements.

Classification and Measurement of Financial Instruments — In January 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which among other changes in accounting and disclosure requirements, replaces the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes, and also eliminates the available-for-sale classification for marketable equity securities. Under the new guidance, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are to be recognized in earnings. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2017. Xcel Energy is currently evaluating the impact of adopting ASU 2016-01 on its consolidated financial statements.

Leases **—** In February 2016, the FASB issued *Leases, Topic 842 (ASU No. 2016-02)*, which, for lessees, requires balance sheet recognition of right-of-use assets and lease liabilities for all leases. Additionally, for leases that qualify as finance leases, the guidance requires expense recognition consisting of amortization of the right-of-use asset as well as interest on the related lease liability using the effective interest method. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018, and early adoption is permitted. Xcel Energy is currently evaluating the impact of adopting ASU 2016-02 on its consolidated financial statements.

Stock Compensation **—** In March 2016, the FASB issued *Improvements to Employee Share-Based Payment Accounting, Topic 718 (ASU 2016-09)*, which amends existing guidance to simplify several aspects of accounting and presentation for share-based payment transactions, including the accounting for income taxes and forfeitures, as well as presentation in the statement of cash flows. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2016, and early adoption is permitted. Xcel Energy does not expect the implementation of ASU 2016-09 to have a material impact on its consolidated financial statements.

Recently Adopted

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. Xcel Energy implemented the guidance on Jan. 1, 2016, and other than the classification of certain real estate investments held within the Nuclear Decommissioning Trust as non-consolidated variable interest entities, the implementation did not have a significant 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 requires the presentation of debt issuance costs on the balance sheet as a deduction from the carrying amount of the related debt, instead of presentation as an asset. Xcel Energy implemented the new guidance as required on Jan. 1, 2016, and as a result, $94.5 million of deferred debt issuance costs were presented as a deduction from the carrying amount of long-term debt on the consolidated balance sheet as of March 31, 2016, and $91.8 million of such deferred costs were retrospectively reclassified from other non-current assets to long-term debt on the consolidated balance sheet as of Dec. 31, 2015.

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 eliminates the requirement to categorize fair value measurements using a net asset value (NAV) methodology in the fair value hierarchy. Xcel Energy implemented the guidance on Jan. 1, 2016, and the implementation did not have a material impact on its consolidated financial statements. For related disclosures, see Note 8 to the consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2016	Dec. 31, 2015
Accounts receivable, net		
Accounts receivable	$ 802,827	$ 776,494
Less allowance for bad debts	(48,579)	(51,888)
	$ 754,248	$ 724,606

(Thousands of Dollars)	Sept. 30, 2016	Dec. 31, 2015
Inventories		
Materials and supplies	$ 306,544	$ 290,690
Fuel	181,265	202,271
Natural gas	127,099	115,623
	$ 614,908	$ 608,584

(Thousands of Dollars)	Sept. 30, 2016	Dec. 31, 2015
Property, plant and equipment, net		
Electric plant	$ 37,335,785	$ 36,464,050
Natural gas plant	5,149,959	4,944,757
Common and other property	1,741,615	1,709,508
Plant to be retired [(a)]	36,852	38,249
Construction work in progress	1,844,525	1,256,949
Total property, plant and equipment	46,108,736	44,413,513
Less accumulated depreciation	(14,218,683)	(13,591,259)
Nuclear fuel	2,469,772	2,447,251
Less accumulated amortization	(2,153,129)	(2,063,654)
	$ 32,206,696	$ 31,205,851

(a) 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. PSCo also expects Craig Unit 1 to be early retired in approximately 2025. 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, 2015 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Tax Loss Carryback Claims — In 2012-2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

***Federal Audit* —** Xcel Energy files a consolidated federal income tax return. In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Sept. 30, 2016, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $14 million of income tax expense for the 2009 through 2011 claims, the 2013 and 2014 claims and the anticipated claim for 2015. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals). In 2016 the IRS audit team and Xcel Energy presented their cases to Appeals; however, the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy’s 2009 through 2011 federal income tax returns, following extensions, expires in June 2017. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of the IRS’s proposed adjustment of the carryback claims. In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of Sept. 30, 2016, 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, 2016, 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	2012

In February 2016, Texas began an audit of years 2009 and 2010. As of Sept. 30, 2016, Texas had not proposed any adjustments.

In June 2016, Minnesota began an audit of years 2010 through 2014. As of Sept. 30, 2016, Minnesota had not proposed any adjustments.

In August 2016, Wisconsin began an audit of years 2012 and 2013. As of Sept. 30, 2016, Wisconsin had not proposed any adjustments. As of Sept. 30, 2016, there were no other 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, 2016	Dec. 31, 2015
Unrecognized tax benefit — Permanent tax positions	$ 27.7	$ 25.8
Unrecognized tax benefit — Temporary tax positions	103.1	94.9
Total unrecognized tax benefit	$ 130.8	$ 120.7

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, 2016	Dec. 31, 2015
NOL and tax credit carryforwards	$ (42.1)	$ (36.7)

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 and audit progress, the Minnesota, Texas and Wisconsin audits progress, and other state audits resume. As the IRS Appeals and IRS, Minnesota, Texas and Wisconsin audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $58 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, 2016 and Dec. 31, 2015 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2016 or Dec. 31, 2015.

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, 2015 and in Note 5 to Xcel Energy Inc.’s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2016 and June 30, 2016, 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)

Minnesota 2016 Multi-Year Electric Rate Case — In November 2015, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested return on equity (ROE) of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below:

Request (Millions of Dollars)	2016	2017	2018
Rate request	$ 194.6	$ 52.1	$ 50.4
Increase percentage	6.4%	1.7%	1.7%
Interim request	$ 163.7	$ 44.9	N/A
Rate base	$ 7,800	$ 7,700	$ 7,700

In December 2015, the MPUC approved interim rates for 2016.

Settlement Agreement

In August 2016, NSP-Minnesota reached a settlement with the Minnesota Department of Commerce (DOC), Xcel Large Industrials, the Minnesota Chamber of Commerce, the Commercial Group, the Suburban Rate Authority, the City of Minneapolis, the Industrial, Commercial, and Institutional Group, and the Energy CENTS Coalition, which resolves all revenue requirement issues in dispute. The settlement agreement requires the approval of the MPUC.

Key terms of the settlement are listed below:

- The agreement reflects a four-year period covering 2016-2019;
- The stated revenue increases in the table below are based on the DOC's sales forecast;
- Annual sales true-up to weather-normalized actuals all years, all classes:
  - 2016 weather-normalized actuals used to set final 2016 rates, no cap;
  - 2016-2019 full decoupling for decoupled classes (residential, non-demand metered commercial) with 3 percent cap; and
  - 2017-2019 annual true-up for non-decoupled classes with 3 percent cap.
- An ROE of 9.2 percent and an equity ratio of 52.5 percent;
- The nuclear related costs in this rate case will not be considered provisional;
- Continued use of all existing riders during the four-year term, however no new riders or legislative additions would be utilized during the four-year term;
- Deferral of incremental 2016 property tax expense above a fixed threshold to 2018 and 2019; and
- A four-year stay out provision for rate cases.

Compliance steps recommended by the settling parties to implement the settlement:

- A property tax true-up mechanism for 2017-2019; and
- A capital expenditure true-up mechanism for 2016-2019.

(Millions of Dollars, incremental)	2016	2017	2018	2019	Total
Settlement revenues [a]	$ 74.99	$ 59.86	$ —	$ 50.12	$ 184.97
NSP-Minnesota's sales forecast [b]	37.40	—	—	—	37.40
Total rate impact	$ 112.39	$ 59.86	$ —	$ 50.12	$ 222.37

(a) The settlement revenue increase reflects an increase of 2.47 percent in 2016; 1.97 percent in 2017; 0 percent in 2018 and 1.65 percent in 2019.

(b) The table reflects the estimated rate impact of this agreement, using NSP-Minnesota's original sales forecast as filed in the Minnesota rate case. The settlement agreement includes a provision to true-up estimated sales to the actual sales for 2016.

The revised schedule for the Minnesota rate case is listed below:

- Administrative law judge (ALJ) report — March 3, 2017; and
- MPUC decision — June 2017.

A current liability that is consistent with the settlement and represents NSP-Minnesota's best estimate of a refund obligation for 2016 associated with interim rates was recorded as of Sept. 30, 2016.

NSP-Minnesota – Gas Utility Infrastructure Costs (GUIC) Rider — In August 2016, the MPUC approved NSP-Minnesota's request to recover approximately $15.5 million in natural gas infrastructure costs through the GUIC Rider, based on NSP-Minnesota's proposed capital structure and a ROE of 9.64 percent. Recovery was approved for the 15-month period from January 2016 to March 2017.

Annual Automatic Adjustment (AAA) of Charges — In June 2016, the DOC recommended the MPUC should hold utilities responsible for incremental costs of replacement power incurred due to unplanned outages at nuclear facilities under certain circumstances. The DOC's recommendation could impact replacement power cost recovery for the Prairie Island (PI) nuclear facility outages allocated to the Minnesota jurisdiction during the AAA fiscal year ended June 30, 2015. NSP-Minnesota expects a MPUC decision in mid-2017.

Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello life cycle management (LCM)/extended power uprate (EPU) project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 megawatts (MW) in 2015. The 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 $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. As a result of these determinations, Xcel Energy recorded an estimated pre-tax loss of $129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

NSP-Wisconsin

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

Wisconsin 2017 Electric and Gas Rate Case — In April 2016, NSP-Wisconsin filed a request with the PSCW for an increase in annual electric rates of $17.4 million, or 2.4 percent, and an increase in natural gas rates by $4.8 million, or 3.9 percent, effective January 2017.

The electric rate request is for the limited purpose of recovering increases in (1) generation and transmission fixed charges and fuel and purchased power expenses related to the interchange agreement with NSP-Minnesota, and (2) costs associated with forecasted average rate base of $1.188 billion in 2017.

The natural gas rate request is for the limited purpose of recovering expenses related to the ongoing environmental remediation of a former manufactured gas plant (MGP) site and adjacent area in Ashland, Wis.

No changes are being requested to the capital structure or the 10.0 percent ROE authorized by the PSCW in the 2016 rate case. As part of an agreement with stakeholders to limit the size and scope of the case, NSP-Wisconsin also agreed to an earnings cap, solely for 2017, in which 100 percent of the earnings in excess of the authorized ROE would be refunded to customers.

In August 2016, the PSCW Staff (Staff) and the intervenors filed their direct testimony in the case. The Staff recommended an electric rate increase of $19.5 million, or 2.7 percent and a natural gas rate increase of $4.8 million, or 3.9 percent. The Staff adjustments reflect revisions to previously forecasted rate base as well as fuel and purchased power expense. The Staff's recommended rate increase also encompasses the PSCW's July 2016 decision to remove the $9.5 million fuel refund credit from the rate case and refund that amount directly to customers in 2016. Adjusting for the treatment of the fuel refund, the Staff's recommendation is $7.4 million less than NSP-Wisconsin's request.

On Oct. 26, 2016, the PSCW verbally approved an electric rate increase of approximately $22.5 million, or 3.2 percent, and a natural gas rate increase of $4.8 million, or 3.9 percent. The difference between the Staff's recommendation and the PSCW's approved electric increase is attributable to an increase in forecasted fuel and purchased power expense. Consistent with long-standing PSCW policy, these costs were updated prior to the PSCW's decision to reflect current market forecasts. The PSCW approved NSP-Wisconsin's requested natural gas rate increase consistent with the Staff's recommendation.

The major components of the retail electric rate increase, the Staff's recommendation, and the PSCW's approval are summarized below:

Electric Rate Request (Millions of Dollars)	NSP-Wisconsin Request	Staff Recommendation	Final Decision
Rate base investments	$ 11.0	$ 7.6	7.6
Generation and transmission expenses (excluding fuel and purchased power) [(a)]	6.8	6.1	6.1
Fuel and purchased power expenses	11.0	7.7	10.7
Subtotal	28.8	21.4	24.4
2015 fuel refund [(b)]	(9.5)	—	—
Department of Energy settlement refund	(1.9)	(1.9)	(1.9)
Total electric rate increase	$ 17.4	$ 19.5	$ 22.5

(a) Includes Interchange Agreement billings. The Interchange Agreement is a Federal Energy Regulatory Commission (FERC) tariff under which NSP-Wisconsin and its affiliate, NSP-Minnesota, own and operate a single integrated electric generation and transmission system and both companies pay a pro-rata share of system capital and operating costs. For financial reporting purposes, these expenses are included in operating and maintenance (O&M).

(b) In July 2016, the PSCW required NSP-Wisconsin to return the 2015 fuel refund directly to customers, rather than using it to offset the proposed 2017 rate increase, as originally proposed by NSP-Wisconsin. This decision, when combined with the increase in forecasted fuel and purchased power expense, effectively increases NSP-Wisconsin's requested electric rate increase to $29.9 million, or 4.2 percent.

NSP-Wisconsin anticipates a final written order later this year, with new rates effective on Jan. 1, 2017.

SPS

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

Appeal of the Texas 2015 Electric Rate Case Decision — In 2014, SPS had requested an overall retail electric revenue rate increase of $64.8 million, which it subsequently revised to $42.1 million. In 2015, the PUCT approved an overall rate decrease of approximately $4.0 million, net of rate case expenses. In April 2016, SPS filed an appeal, with the Texas State District Court, of the PUCT's order that had denied SPS' request for rehearing on certain items in SPS' Texas 2015 electric rate case related to capital structure, incentive compensation and wholesale load reductions. The hearing in the appeal is scheduled for February 2017.

Texas 2016 Electric Rate Case — In February 2016, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the PUCT requesting an overall increase in annual base rate revenue of approximately $71.9 million, or 14.4 percent. The filing is based on a historic test year (HTY) ended Sept. 30, 2015, a requested ROE of 10.25 percent, an electric rate base of approximately $1.7 billion, and an equity ratio of 53.97 percent. In SPS' required update filing in April 2016, SPS revised its requested rate increase to $68.6 million.

Pursuant to legislation passed in Texas in 2015, the final rates established in the case will be effective retroactive to July 20, 2016.

In August 2016, several intervenors filed direct testimony in response to SPS' rate request, including: PUCT Staff (Staff), the Alliance of Xcel Municipalities (AXM), the Office of Public Utility Counsel (OPUC), Texas Industrial Energy Consumers (TIEC), and the State of Texas' agencies.

- The Staff recommended a rate increase of approximately $32.9 million, based on a ROE of 9.30 percent and an equity ratio of 51 percent. The Staff's proposed rate increase reflects imputed revenues for power factor adjustment charges and weather normalization;
- AXM recommended a rate increase of approximately $25.2 million, based on a ROE of 9.40 percent and an equity ratio of 51 percent; and
- The other intervenors did not present a complete revenue requirement analysis. The majority of the direct testimony focused on specific cost allocation and rate design issues. However, OPUC and TIEC recommended ROEs of 9.20 percent and 9.15 percent, respectively.

In October 2016, SPS and various parties reached an agreement in principle in the Texas rate case. SPS and the parties are documenting the settlement, and expect to file with the PUCT in the fourth quarter of 2016. Any settlement would require approval of the PUCT, with a decision expected by the end of 2016 or early 2017.

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

New Mexico 2015 Electric Rate Case — In October 2015, SPS filed an electric rate case with the NMPRC seeking an increase in non-fuel base rates of $45.4 million. The proposed increase would be offset by a decrease in base fuel revenue of approximately $21.1 million. The rate filing was based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric rate base of approximately $734 million and an equity ratio of 53.97 percent.

In August 2016, the NMPRC approved a black-box stipulation that resulted in a non-fuel base rate increase of $23.5 million and a decrease in base fuel revenue of approximately $21.1 million. The decrease in base fuel revenue will be reflected in adjustments to the fuel and purchased power cost adjustment clause.

SPS plans to file another base rate case in November 2016 utilizing a future test year ending June 2018.

Pending Regulatory Proceedings — 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 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 for being an independent transmission company), effective Nov. 12, 2013.

In December 2015, an ALJ initial decision recommended the FERC approve a ROE of 10.32 percent, which the FERC upheld in an order issued on Sept. 28, 2016. This ROE is applicable for the 15 month refund period from Nov. 12, 2013 to Feb. 11, 2015, and prospectively from the date of the FERC order. The total prospective ROE is 10.82 percent, which includes a previously approved 50 basis point adder for RTO membership.

In February 2015, a second complaint seeking to reduce the MISO region ROE from 12.38 percent to 8.67 percent prior to any adder was filed, which the FERC set for hearings, resulting in a second period of potential refund from Feb. 12, 2015 to May 11, 2016. The MPUC, the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission and the DOC joined a joint complainant/intervenor initial brief recommending an ROE of approximately 8.81 percent. FERC staff recommended a ROE of 8.78 percent. The MISO TOs recommended a ROE of 10.92 percent. On June 30, 2016, the ALJ recommended a ROE of 9.7 percent, the midpoint of the upper half of the discounted cash flow range. A FERC decision is expected in 2017.

As of Sept. 30, 2016, NSP-Minnesota has recognized a current liability for the Nov. 12, 2013 to Feb. 11, 2015 complaint period based on the 10.32 percent ROE provided in the FERC order, as well as a current liability representing the best estimate of the final ROE for the second complaint period.

Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT) Upgrade Costs — Under the SPP OATT, costs of participant-funded, or “sponsored,” transmission upgrades may be recovered, in part, from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to collect charges since 2008, but to date SPP has not charged its customers any amounts attributable to these upgrades.

In April 2016, SPP filed a request with the FERC for a waiver that would allow SPP to recover the charges not billed since 2008. The FERC approved the waiver request in July 2016. SPS and certain other parties requested rehearing of the FERC order. In September 2016, SPP provided further information regarding additional costs, primarily due to the system-wide claw back of point to point revenues previously distributed to SPS and other entities. Amounts due to SPP are expected to be paid over a five-year period commencing November 2016 under an optional payment plan that was approved by the FERC in September 2016 and elected by SPS in October 2016. Based on SPP’s most recent calculation in October 2016, estimated costs would be approximately $12 million to $14 million, and SPS anticipates these costs would be recoverable through regulatory mechanisms.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5 above, the circumstances set forth in Notes 12, 13 and 14 to the consolidated financial statements included in Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2015, 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, 2016 and June 30, 2016, 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 3,537 MW and 3,698 MW of capacity under long-term PPAs as of Sept. 30, 2016 and Dec. 31, 2015, 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 2041.

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 have a stated maximum guarantee or indemnity amount. As of Sept. 30, 2016 and Dec. 31, 2015, 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:

(Millions of Dollars)	Sept. 30, 2016	Dec. 31, 2015
Guarantees issued and outstanding	$ 19.0	$ 12.5
Current exposure under these guarantees	0.1	0.1
Bonds with indemnity protection	43.0	41.3

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 future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Environmental Contingencies

Ashland 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 Site) includes NSP-Wisconsin property, previously operated as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park); and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

In 2012, under a settlement agreement with the United States Environmental Protection Agency (EPA), NSP-Wisconsin agreed to remediate the Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site). The current cost estimate for the cleanup of the Phase I Project Area is approximately $71.4 million, of which approximately $52.6 million has been spent.

NSP-Wisconsin performed a wet dredge pilot study in the summer of 2016 and demonstrated that a wet dredge remedy can meet the performance standards for remediation of the Sediments. As a result, the EPA authorized NSP-Wisconsin to extend the wet dredge pilot to additional areas of the Site. Settlement negotiations are ongoing between the EPA and NSP-Wisconsin regarding the performance of the full scale cleanup of the Sediments. If a court-approved settlement can be reached with the EPA, NSP-Wisconsin anticipates a full scale wet dredge remedy of the Sediments could be performed beginning as early as 2017, and potentially conclude by 2018.

At Sept. 30, 2016 and Dec. 31, 2015, NSP-Wisconsin had recorded a total liability of $84.6 million and $94.4 million, respectively, for the entire site. NSP-Wisconsin's potential liability, the actual cost of remediation and the timing of expenditures are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the remediation cost.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has consistently authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In 2012, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a ten-year period, and to apply a three percent carrying cost to the unamortized regulatory asset. In April 2016, NSP-Wisconsin filed a limited natural gas rate case for recovery of additional expenses associated with remediating the Site. If approved, the annual recovery of MGP clean-up costs would increase from $7.6 million in 2016 to $12.4 million in 2017.

Fargo, N.D. MGP Site — In May 2015, underground pipes, tars and impacted soils were discovered in a right-of-way in Fargo, N.D. that appeared to be associated with a former MGP operated by NSP-Minnesota or prior companies. NSP-Minnesota removed impacted soils and other materials from the right-of-way at that time and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). Based on the investigation that concluded in the third quarter of 2016, NSP-Minnesota has recommended that targeted source removal of impacted soils and historic MGP infrastructure should be performed, subject to further input from the North Dakota Department of Health, the City of Fargo, N.D., current property owners and other stakeholders.

NSP-Minnesota has initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota agreed to the parties' request for a stay of the litigation until November 2016 to allow NSP-Minnesota time to investigate site conditions. NSP-Minnesota intends to seek an additional stay of the litigation.

As of Sept. 30, 2016 and Dec. 31, 2015, NSP-Minnesota had recorded a liability of $12.2 million and $2.7 million, respectively, for the Fargo MGP Site, with the increase due to the remediation activities proposed by NSP-Minnesota. In December 2015, the NDPSC approved NSP-Minnesota's request to defer costs associated with the Fargo MGP Site, resulting in deferral of all investigation and response costs with the exception of 12 percent allocable to the Minnesota jurisdiction. Uncertainties related to the liability recognized include obtaining access and approvals from stakeholders to perform the proposed remediation and the potential for contributions from entities that may be identified as PRPs.

Environmental Requirements

Water and Waste

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

In 2015, industry and environmental non-governmental organizations sought judicial review of the final rule. In June 2016, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an order remanding and vacating certain elements of the rule as a result of partial settlements with these parties. Oral arguments are expected to be heard in early 2017 and a final decision is anticipated in the first half of 2017. Until a final decision is reached in the case, it is uncertain whether the litigation or partial settlements will have any significant impact on results of operations, financial position or cash flows on Xcel Energy.

Air

Cross-State Air Pollution Rule (CSAPR) — CSAPR addresses long range transport of particulate matter (PM) and ozone by requiring reductions in sulfur dioxide (SO_2) and nitrogen 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.

CSAPR was adopted to address interstate emissions impacting downwind states' attainment of the 1997 ozone National Ambient Air Quality Standard (NAAQS) and the 1997 and 2006 particulate NAAQS. As the EPA revises the NAAQS, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program. In December 2015, the EPA proposed adjustments to CSAPR emission budgets which address attainment of the more stringent 2008 ozone NAAQS. In September 2016 the EPA adopted a final rule that reduced the ozone season emission budget for NOx in Texas by approximately 22 percent, which is expected to lead to increased costs to purchase emission allowances. Xcel Energy does not anticipate these increased costs to purchase emission allowances will have a material impact on the results of operations, financial position or cash flows.

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. In 2005, the EPA amended the best available retrofit technology (BART) requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. Under BART, regional haze plans identify facilities that will have to reduce SO_2, NOx and PM emissions and set emission limits for those facilities. BART requirements can also be met through participation in interstate emission trading programs such as the Clean Air Interstate Rule (CAIR) and its successor, CSAPR.

Texas developed a state implementation plan (SIP) that finds the CAIR equal to BART for electric generating units (EGUs). As a result, no additional controls beyond CAIR compliance would be required. In December 2014, the EPA proposed to approve the BART portion of the SIP, with substitution of CSAPR compliance for Texas' reliance on CAIR. In January 2016, the EPA adopted a final rule that defers its approval of CSAPR compliance as BART until the EPA considers further adjustments to CSAPR emission budgets under the D.C. Circuit's remand of the Texas SO_2 emission budgets. In March 2016, the EPA requested information under the Clean Air Act related to EGUs at SPS' plants. SPS identified Harrington Units 1 and 2, Jones Units 1 and 2, Nichols Unit 3 and Plant X Unit 4 as BART-eligible units. These units will be evaluated based on their impact on visibility. Additional emission control equipment under the EPA's BART guidelines for PM, SO_2 and NOx could be required if a unit is determined to "cause or contribute" to visibility impairment. SPS cannot evaluate the impact of additional emission controls until the EPA concludes its evaluation of BART. In June 2016, the EPA issued a memorandum which allows Texas to voluntarily adopt the CSAPR emission budgets limiting annual SO_2 and NOx emissions and rely on those emission budgets to satisfy Texas' BART obligations under the regional haze rules. It is not yet known whether the Texas Commission on Environmental Quality (TCEQ) intends to utilize this option. If Texas does not opt into the CSAPR rule, the EPA is expected to issue a proposed rule in December 2016 that could impact Harrington Units 1 and 2.

In December 2014, the EPA proposed to disapprove portions of the SIP and instead adopt a federal implementation plan (FIP). In January 2016, the EPA adopted a final rule establishing a FIP for the state of Texas, which imposed SO_2 emission limitations that reflect the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be approximately $600 million. In March 2016, SPS appealed the EPA's decision and asked for a stay of the final rule while it is being reviewed. In July 2016, the United States Court of Appeals for the Fifth Circuit (Fifth Circuit) granted the stay motion and decided that the Fifth Circuit, not the D.C. Circuit, is the appropriate venue for this case. In addition, SPS filed a petition with the EPA requesting reconsideration of the final rule. SPS believes these costs or the costs of alternative cost-effective generation would be recoverable through regulatory mechanisms if required, and therefore does not expect a material impact on results of operations, financial position or cash flows.

Implementation of the NAAQS for SO_2 — The EPA adopted a more stringent NAAQS for SO_2 in 2010. 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. In June 2016, the EPA issued final designations which found the area near the Tolk plant to be meeting the NAAQS and the areas near the Harrington and Pawnee plants as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020. It is anticipated that the area near the Pawnee plant will be able to show compliance with the NAAQS through air dispersion modeling performed by the Colorado Department of Public Health and Environment.

If an area is designated nonattainment in 2020, the states will need to evaluate all SO_2 sources in the area. The state would then submit an implementation plan, which would be due by 2022, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. The areas near the remaining Xcel Energy power plants will be evaluated in the next designation phase, ending December 2017. The remaining plants, PSCo's Comanche and Hayden plants along with NSP-Minnesota's King and Sherco plants, utilize scrubbers to control SO_2 emissions. Xcel Energy cannot evaluate the impacts 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 or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

In light of the continuing development of environmental regulatory requirements, as well as the more favorable long term outlook for alternative resources, SPS is undertaking analysis to determine the most cost-effective means to meet the needs of its customers, given a low natural gas price environment, the need to make additional investments to provide water to the Tolk facility and the potential need to make major investments in air pollution control equipment.

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 — A complaint with the FERC posed that sales made in the Pacific Northwest in 2000 and 2001 through bilateral contracts were unjust and unreasonable under the Federal Power Act. The City of Seattle (the City) alleges between $34 million to $50 million in sales with PSCo is subject to refund. In 2003, the FERC terminated the proceeding, although it was later remanded back to the FERC in 2007 by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit).

In May 2015, the FERC issued an order rejecting the City's claim that any of the sales made resulted in an excessive burden and concluded that the City failed to establish a causal link between any contracts and any claimed unlawful market activity. In February 2016, the City appealed this decision to the Ninth Circuit. This appeal is pending review by the Ninth Circuit.

In December 2015, the Ninth Circuit held that the standard of review applied by the FERC to the contracts which the City was challenging is appropriate. The Ninth Circuit dismissed questions concerning whether the FERC properly established the scope of the hearing, and determined that the challenged orders are preliminary and that the Ninth Circuit lacks jurisdiction to review evidentiary decisions until after the FERC's proceedings are final. The City joined the State of California in its request seeking rehearing of this order, which the Ninth Circuit denied. The FERC proceedings are now final with respect to the City's claims and are subject to review in the pending Ninth Circuit appeal.

In October 2016, a settlement was reached that resolves all outstanding claims between and among the City and the respondents, including PSCo. Settlement terms required PSCo to pay the City $15,000 and the City to withdraw its pending appeal with the Ninth Circuit. This brings this matter to a close.

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. Five of the cases have since been settled and seven have been dismissed. One multi-district litigation (MDL) matter remains and it consists of a Colorado class (Breckenridge), a Wisconsin class (NSP-Wisconsin), a Kansas class, and two other cases identified as "Sinclair Oil" and "Farmland." In May 2016, the MDL judge granted summary judgment dismissing defendants from the Farmland lawsuit. e prime and Xcel Energy have filed a motion seeking clarification that this order includes them. This motion is currently pending and is expected to be heard in December 2016. The e prime defendants filed a summary judgment motion in the Colorado class lawsuit (Breckenridge) and oppositions to class certifications in all the class actions, which is also expected to be heard in December 2016. Trial dates are not expected to occur prior to early 2017. Xcel Energy, NSP-Wisconsin and e prime have concluded that a loss is remote.

Line Extension Disputes — In December 2015, Development Recovery Company (DRC) filed a lawsuit in Denver State Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric service agreements entered into by PSCo and various developers. The dispute involves assigned interests in those claims by over fifty developers. In May 2016, the district court granted PSCo's motion to dismiss the lawsuit, concluding that jurisdiction over this dispute resides with the Colorado Public Utilities Commission (CPUC). In June 2016, DRC filed a notice of appeal. DRC filed its opening brief on Oct. 20, 2016 and PSCo's answer brief is due Nov. 24, 2016. DRC also brought a proceeding before the CPUC as assignee on behalf of two developers, Ryland Homes and Richmond Homes of Colorado. In March 2016, the ALJ issued an order rejecting DRC's claims for additional allowances and refunds. In June 2016, the ALJ's determination was approved by the CPUC. DRC did not file a request for reconsideration before the CPUC contesting the decision, but filed an appeal in Denver District Court in August 2016.

PSCo has concluded that a loss is remote with respect to this matter as the service agreements were developed to implement CPUC approved tariffs and PSCo has complied with the tariff provisions. Also, if a loss were sustained, PSCo believes it would be allowed to recover these costs through traditional regulatory mechanisms. The amount or range in dispute is presently unknown and no accrual has been recorded for this matter.

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 Sept. 30, 2016	Year Ended Dec. 31, 2015
Borrowing limit	$ 2,750	$ 2,750
Amount outstanding at period end	366	846
Average amount outstanding	477	601
Maximum amount outstanding	609	1,360
Weighted average interest rate, computed on a daily basis	0.77%	0.48%
Weighted average interest rate at period end	0.77	0.82

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, 2016 and Dec. 31, 2015, there were $19 million and $29 million, respectively, of letters of credit outstanding under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facilities **—** In order to use their commercial paper programs, Xcel Energy Inc. and its utility subsidiaries must have credit facilities in place at least equal to the amount of their commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available credit facility capacity. 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, 2016, 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	$ 362	$ 638
PSCo	700	3	697
NSP-Minnesota	500	11	489
SPS	400	5	395
NSP-Wisconsin	150	4	146
Total	$ 2,750	$ 385	$ 2,365

(a) These credit facilities expire in June 2021.

(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, 2016 and Dec. 31, 2015.

Amended Credit Agreements - In June 2016, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements remained at $2.75 billion. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the following exceptions:

- The maturity extended from October 2019 to June 2021.
- The Eurodollar borrowing margins on these lines of credit were reduced to a range of 75 to 150 basis points per year, from a range of 87.5 to 175 basis points per year, based upon applicable long-term credit ratings.
- The commitment fees, calculated on the unused portion of the lines of credit, were reduced to a range of 6 to 22.5 basis points per year, from a range of 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS 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.

Long-Term Borrowings

During the nine months ended Sept. 30, 2016, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In March, Xcel Energy Inc. issued $400 million of 2.4 percent senior notes due March 15, 2021 and $350 million of 3.3 percent senior notes due June 1, 2025;
- In May, NSP-Minnesota issued $350 million of 3.6 percent first mortgage bonds due May 15, 2046;
- In June, PSCo issued $250 million of 3.55 percent first mortgage bonds due June 15, 2046; and
- In August, SPS issued $300 million of 3.4 percent first mortgage bonds due Aug. 15, 2046.

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 measurement 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 prices.

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 a NAV methodology, which takes 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 NAV 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.

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 and SPS include transmission congestion instruments, referred to as financial transmission rights (FTRs). 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 transmission load and transmission constraints. Congestion is also influenced by the operating schedules of power plants and the consumption of electricity. Unplanned plant outages, scheduled plant maintenance, changes in the costs of fuels used in generation, weather and changes in demand for electricity can each impact the operating schedules of the power plants 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 fair value measurements for FTRs have been assigned a Level 3. Monthly settlements for non-trading FTRs are included in 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

Nuclear Decommissioning Fund

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. 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, given the purpose and legal restrictions on the use of nuclear decommissioning fund assets. 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 $355.3 million and $328.8 million at Sept. 30, 2016 and Dec. 31, 2015, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $65.8 million and $100.2 million at Sept. 30, 2016 and Dec. 31, 2015, 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, 2016 and Dec. 31, 2015:

	Sept. 30, 2016					
		Fair Value				
(Thousands of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**Investments Measured at NAV (b)**	**Total**
Nuclear decommissioning fund (a)						
Cash equivalents	$ 15,055	$ 15,055	$ —	$ —	$ —	$ 15,055
Commingled funds:						
Non U.S. equities	254,362	—	—	—	245,481	245,481
Emerging market debt funds	92,472	—	—	—	101,387	101,387
Commodity funds	99,771	—	—	—	82,139	82,139
Private equity investments	130,848	—	—	—	178,768	178,768
Real estate	121,271	—	—	—	174,552	174,552
Other commingled funds	151,048	—	—	—	159,230	159,230
Debt securities:						
Government securities	34,853	—	35,723	—	—	35,723
U.S. corporate bonds	95,828	—	93,981	—	—	93,981
International corporate bonds	19,877	—	19,860	—	—	19,860
Municipal bonds	13,906	—	14,638	—	—	14,638
Asset-backed securities	2,847	—	2,948	—	—	2,948
Mortgage-backed securities	10,118	—	10,582	—	—	10,582
Equity securities:						
U.S. equities	270,137	455,035	—	—	—	455,035
Non U.S. equities	213,291	225,782	—	—	—	225,782
Total	$ 1,525,684	$ 695,872	$ 177,732	$ —	$ 941,557	$ 1,815,161

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $134.5 million of equity investments in unconsolidated subsidiaries and $98.8 million of rabbi trust assets and miscellaneous investments.

(b) Based on the requirements of ASU 2015-07, investments measured at fair value using a NAV methodology have not been classified in the fair value hierarchy. See Note 2 for further information on the adoption of ASU 2015-07.

	Dec. 31, 2015					
		Fair Value				
(Thousands of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**Investments Measured at NAV (b)**	**Total**
Nuclear decommissioning fund (a)						
Cash equivalents	$ 27,484	$ 27,484	$ —	$ —	$ —	$ 27,484
Commingled funds:						
Non U.S. equities	259,114	—	—	—	231,122	231,122
Emerging market debt funds	88,987	—	—	—	88,467	88,467
Commodity funds	99,771	—	—	—	77,338	77,338
Private equity investments	105,965	—	—	—	157,528	157,528
Real estate	115,019	—	—	—	165,190	165,190
Other commingled funds	150,877	—	—	—	164,389	164,389
Debt securities:						
Government securities	24,444	—	21,356	—	—	21,356
U.S. corporate bonds	73,061	—	65,276	—	—	65,276
International corporate bonds	13,726	—	12,801	—	—	12,801
Municipal bonds	49,255	—	51,589	—	—	51,589
Asset-backed securities	2,837	—	2,830	—	—	2,830
Mortgage-backed securities	11,444	—	11,621	—	—	11,621

Equity securities:						
U.S. equities	273,106	432,495	—	—	—	432,495
Non U.S. equities	200,509	214,664	—	—	—	214,664
Total	$ 1,495,599	$ 674,643	$ 165,473	$ —	$ 884,034	$ 1,724,150

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $130.0 million of equity investments in unconsolidated subsidiaries and $48.9 million of miscellaneous investments.

(b) Based on the requirements of ASU 2015-07, investments measured at fair value using a NAV methodology have not been classified in the fair value hierarchy. See Note 2 for further information on the adoption of ASU 2015-07.

For the nine months ended Sept. 30, 2016 and 2015 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Sept. 30, 2016:

	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	$ —	$ 10,583	$ 971	$ 24,169	$ 35,723
U.S. corporate bonds	257	28,245	59,451	6,028	93,981
International corporate bonds	—	5,043	11,606	3,211	19,860
Municipal bonds	—	210	5,773	8,655	14,638
Asset-backed securities	—	—	2,948	—	2,948
Mortgage-backed securities	—	—	—	10,582	10,582
Debt securities	$ 257	$ 44,081	$ 80,749	$ 52,645	$ 177,732

Rabbi Trusts

In June 2016, Xcel Energy established rabbi trusts to provide funding for future distributions of its supplemental executive retirement plan and nonqualified pension plans. The following table presents the cost and fair value of the assets held in rabbi trusts at Sept. 30, 2016:

	Sept. 30, 2016				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 47,762	$ 47,762	$ —	$ —	$ 47,762
Mutual funds	1,594	1,867	—	—	1,867
Total	$ 49,356	$ 49,629	$ —	$ —	$ 49,629

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

An immaterial amount of mutual funds were held in rabbi trusts at Dec. 31, 2015.

Derivative Instruments Fair Value Measurements

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

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

At Sept. 30, 2016, accumulated other comprehensive losses related to interest rate derivatives included $3.4 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for 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.

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, 2016, 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, 2016 and 2015.

At Sept. 30, 2016, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included immaterial 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, 2016 and Dec. 31, 2015:

(Amounts in Thousands) [(a)(b)]	**Sept. 30, 2016**	**Dec. 31, 2015**
Megawatt hours of electricity	64,040	50,487
Million British thermal units of natural gas	116,144	20,874
Gallons of vehicle fuel	35	141

(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, 2016 and 2015, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2016				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1,502 [a]	$ —	$ —
Vehicle fuel and other commodity	(6)	—	46 [b]	—	—
Total	$ (6)	$ —	$ 1,548	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 1,779 [c]
Electric commodity	—	15,497	—	2,491 [d]	—
Natural gas commodity	—	(5,737)	—	—	(6) [e]
Total	$ —	$ 9,760	$ —	$ 2,491	$ 1,773

	Nine Months Ended Sept. 30, 2016				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 4,470 [a]	$ —	$ —
Vehicle fuel and other commodity	7	—	150 [b]	—	—
Total	$ 7	$ —	$ 4,620	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 3,269 [c]
Electric commodity	—	14,528	—	30,024 [d]	—
Natural gas commodity	—	(2,376)	—	11,666 [e]	(5,005) [e]
Total	$ —	$ 12,152	$ —	$ 41,690	$ (1,736)

	Three Months Ended Sept. 30, 2015				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Losses Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 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)

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2015 — Pre-Tax Fair Value Losses Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax 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)

(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, 2016 included no settlement gains or 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. 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. The remaining derivative settlement gains and losses for the three and nine months ended Sept. 30, 2016 and 2015 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, 2016 and 2015. 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 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. 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, 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 are contracts with counterparties to their wholesale, trading and non-trading commodity activities. At Sept. 30, 2016, one of Xcel Energy's 10 most significant counterparties for these activities, comprising $14.1 million or 6 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's Ratings Services, Moody's Investor Services or Fitch Ratings. Nine of the 10 most significant counterparties, comprising $73.4 million or 33 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. All ten of these significant counterparties are RTOs, municipal or cooperative electric entities or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. At Sept. 30, 2016 and Dec. 31, 2015, 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 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, 2016 and Dec. 31, 2015.

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, 2016:

	Sept. 30, 2016					
	Fair Value					
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Counterparty Netting [b]**	**Total**
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ 3,846	$ 11,239	$ —	$ 15,085	$ (9,440)	$ 5,645
Electric commodity	—	—	27,775	27,775	(3,180)	24,595
Natural gas commodity	—	6,034	—	6,034	(15)	6,019
Total current derivative assets	$ 3,846	$ 17,273	$ 27,775	$ 48,894	$ (12,635)	36,259
PPAs [a]						6,601
Current derivative instruments						$ 42,860
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ 501	$ 32,538	$ —	$ 33,039	$ (8,306)	$ 24,733
Natural gas commodity	—	681	—	681	—	681
Total noncurrent derivative assets	$ 501	$ 33,219	$ —	$ 33,720	$ (8,306)	25,414
PPAs [a]						25,955
Noncurrent derivative instruments						$ 51,369

	Sept. 30, 2016					
	Fair Value					
(Thousands of Dollars)	**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	$ —	$ 41	$ —	$ 41	$ —	$ 41
Other derivative instruments:						
Commodity trading	3,921	8,000	—	11,921	(9,527)	2,394
Electric commodity	—	—	3,180	3,180	(3,180)	—
Natural gas commodity	—	15	—	15	(15)	—
Total current derivative liabilities	$ 3,921	$ 8,056	$ 3,180	$ 15,157	$ (12,722)	2,435
PPAs [a]						22,766
Current derivative instruments						$ 25,201
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$ 538	$ 24,114	$ —	$ 24,652	$ (11,005)	$ 13,647
Total noncurrent derivative liabilities	$ 538	$ 24,114	$ —	$ 24,652	$ (11,005)	13,647
PPAs [a]						141,003
Noncurrent derivative instruments						$ 154,650

(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, 2016. At Sept. 30, 2016, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $2.8 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, 2015:

	Dec. 31, 2015					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$ 225	$ 10,620	$ 1,250	$ 12,095	$ (5,865)	$ 6,230
Electric commodity	—	—	21,421	21,421	(4,088)	17,333
Natural gas commodity	—	496	—	496	(303)	193
Total current derivative assets	$ 225	$ 11,116	$ 22,671	$ 34,012	$ (10,256)	23,756
PPAs [(a)]						10,086
Current derivative instruments						$ 33,842
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 27,416	$ —	$ 27,416	$ (6,555)	$ 20,861
Total noncurrent derivative assets	$ —	$ 27,416	$ —	$ 27,416	$ (6,555)	20,861
PPAs [(a)]						30,222
Noncurrent derivative instruments						$ 51,083

	Dec. 31, 2015					
	Fair Value					
(Thousands of Dollars)	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	$ —	$ 205	$ —	$ 205	$ —	$ 205
Other derivative instruments:						
Commodity trading	152	7,866	555	8,573	(6,904)	1,669
Electric commodity	—	—	4,088	4,088	(4,088)	—
Natural gas commodity	—	5,407	—	5,407	(303)	5,104
Total current derivative liabilities	$ 152	$ 13,478	$ 4,643	$ 18,273	$ (11,295)	6,978
PPAs [(a)]						22,861
Current derivative instruments						$ 29,839
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$ —	$ 19,898	$ —	$ 19,898	$ (9,780)	$ 10,118
Total noncurrent derivative liabilities	$ —	$ 19,898	$ —	$ 19,898	$ (9,780)	10,118
PPAs [(a)]						158,193
Noncurrent derivative instruments						$ 168,311

(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, 2015. At Dec. 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $4.3 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, 2016 and 2015:

	Three Months Ended Sept. 30	
(Thousands of Dollars)	2016	2015
Balance at July 1	$ 24,517	$ 46,826
Purchases	274	486
Settlements	(33,982)	(20,216)
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	9	121
Gains recognized as regulatory assets and liabilities	33,777	3,966
Balance at Sept. 30	$ 24,595	$ 31,183

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2016	2015
Balance at Jan. 1	$ 18,028	$ 56,155
Purchases	33,296	63,724
Settlements	(60,707)	(57,462)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings [(a)]	(33)	1,401
Gains (losses) recognized as regulatory assets and liabilities	34,011	(32,635)
Balance at Sept. 30	$ 24,595	$ 31,183

(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, 2016 and 2015.

Fair Value of Long-Term Debt

As of Sept. 30, 2016 and Dec. 31, 2015, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Sept. 30, 2016		Dec. 31, 2015	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion [(a)]	$ 14,112,150	$ 16,127,060	$ 13,055,901	$ 14,094,744

(a) Amounts reflect the classification of debt issuance costs as a deduction from the carrying amount of the related debt. See Note 2, *Accounting Pronouncements* for more information on the adoption of ASU 2015-03.

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, 2016 and Dec. 31, 2015, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

9. Other Income, Net

Other income, net consisted of the following:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Thousands of Dollars)	2016	2015	2016	2015
Interest income	$ 1,385	$ 312	$ 6,439	$ 4,939
Other nonoperating income	341	625	2,517	2,387
Insurance policy (expense) income	(1,148)	689	(2,568)	(1,578)
Other income, net	$ 578	$ 1,626	$ 6,388	$ 5,748

10. Segment Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy’s chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits and distributes electricity primarily in portions of Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $134.5 million and $130.0 million as of Sept. 30, 2016 and Dec. 31, 2015, 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, 2016					
Operating revenues from external customers	$ 2,799,964	$ 221,956	$ 18,227	$ —	$ 3,040,147
Intersegment revenues	282	292	—	(574)	—
Total revenues	$ 2,800,246	$ 222,248	$ 18,227	$ (574)	$ 3,040,147
Net income (loss)	$ 479,399	$ (5,297)	$ (16,307)	$ —	$ 457,795

(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
Nine Months Ended Sept. 30, 2016					
Operating revenues from external customers	$ 7,209,225	$ 1,046,544	$ 56,500	$ —	$ 8,312,269
Intersegment revenues	1,038	820	—	(1,858)	—
Total revenues	$ 7,210,263	$ 1,047,364	$ 56,500	$ (1,858)	$ 8,312,269
Net income (loss)	$ 863,076	$ 84,974	$ (52,148)	$ —	$ 895,902

(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	$ 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

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

11. Earnings Per Share

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

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

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

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

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, 2016			Three Months Ended Sept. 30, 2015		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$ 457,795	—	—	$ 426,463	—	—
Basic EPS:						
Earnings available to common shareholders	457,795	508,941	$ 0.90	426,463	508,031	$ 0.84
Effect of dilutive securities:						
Time based equity awards	—	625	—	—	396	—
Diluted EPS:						
Earnings available to common shareholders	$ 457,795	509,566	$ 0.90	$ 426,463	508,427	$ 0.84

(Amounts in thousands, except per share data)	Nine Months Ended Sept. 30, 2016 Income	Shares	Per Share Amount	Nine Months Ended Sept. 30, 2015 Income	Shares	Per Share Amount
Net income	$ 895,902	—	—	$ 775,460	—	—
Basic EPS:						
Earnings available to common shareholders	895,902	508,840	$ 1.76	775,460	507,585	$ 1.53
Effect of dilutive securities:						
Time based equity awards	—	556	—	—	391	—
Diluted EPS:						
Earnings available to common shareholders	$ 895,902	509,396	$ 1.76	$ 775,460	507,976	$ 1.53

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2016	2015	2016	2015
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 22,940	$ 24,828	$ 432	$ 529
Interest cost	40,027	37,131	6,527	6,324
Expected return on plan assets	(52,575)	(53,473)	(6,249)	(6,650)
Amortization of prior service credit	(478)	(451)	(2,672)	(2,672)
Amortization of net loss	24,384	31,288	1,011	1,351
Net periodic benefit cost (credit)	34,298	39,323	(951)	(1,118)
Costs not recognized due to the effects of regulation	(3,976)	(7,016)	—	—
Net benefit cost (credit) recognized for financial reporting	$ 30,322	$ 32,307	$ (951)	$ (1,118)

	Nine Months Ended Sept. 30			
	2016	2015	2016	2015
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 68,805	$ 74,484	$ 1,295	$ 1,587
Interest cost	120,078	111,393	19,580	18,972
Expected return on plan assets	(157,725)	(160,418)	(18,746)	(19,950)
Amortization of prior service credit	(1,439)	(1,353)	(8,015)	(8,015)
Amortization of net loss	73,154	93,864	3,031	4,053
Net periodic benefit cost (credit)	102,873	117,970	(2,855)	(3,353)
Costs not recognized due to the effects of regulation	(12,587)	(22,035)	—	—
Net benefit cost (credit) recognized for financial reporting	$ 90,286	$ 95,935	$ (2,855)	$ (3,353)

In January 2016, contributions of $125.0 million were made across four of Xcel Energy’s pension plans. Xcel Energy does not expect additional pension contributions during 2016.

13. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the three and nine months ended Sept. 30, 2016 and 2015 were as follows:

	Three Months Ended Sept. 30, 2016			
(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	$ (52,980)	$ 110	$ (53,925)	$ (106,795)
Other comprehensive loss before reclassifications	(4)	—	—	(4)
Losses reclassified from net accumulated other comprehensive loss	960	—	878	1,838
Net current period other comprehensive income	956	—	878	1,834
Accumulated other comprehensive (loss) income at Sept. 30	$ (52,024)	$ 110	$ (53,047)	$ (104,961)

	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
Accumulated other comprehensive (loss) income at Sept. 30	$ (55,772)	$ 111	$ (47,978)	$ (103,639)

	Nine Months Ended Sept. 30, 2016			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$ (54,862)	$ 110	$ (55,001)	$ (109,753)
Other comprehensive income (loss) before reclassifications	4	—	(653)	(649)
Losses reclassified from net accumulated other comprehensive loss	2,834	—	2,607	5,441
Net current period other comprehensive income	2,838	—	1,954	4,792
Accumulated other comprehensive (loss) income at Sept. 30	$ (52,024)	$ 110	$ (53,047)	$ (104,961)

	Nine 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 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)

Reclassifications from accumulated other comprehensive loss for the three and nine months ended Sept. 30, 2016 and 2015 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss — Three Months Ended Sept. 30, 2016		Amounts Reclassified from Accumulated Other Comprehensive Loss — Three Months Ended Sept. 30, 2015	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$ 1,502	(a)	$ 1,118	(a)
Vehicle fuel derivatives	46	(b)	34	(b)
Total, pre-tax	1,548		1,152	
Tax benefit	(588)		(446)	
Total, net of tax	960		706	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	1,478	(c)	1,532	(c)
Prior service credit	(64)	(c)	(89)	(c)
Total, pre-tax	1,414		1,443	
Tax benefit	(536)		(559)	
Total, net of tax	878		884	
Total amounts reclassified, net of tax	$ 1,838		$ 1,590	

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss — Nine Months Ended Sept. 30, 2016		Amounts Reclassified from Accumulated Other Comprehensive Loss — Nine Months Ended Sept. 30, 2015	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$ 4,470	(a)	$ 3,013	(a)
Vehicle fuel derivatives	150	(b)	88	(b)
Total, pre-tax	4,620		3,101	
Tax benefit	(1,786)		(1,210)	
Total, net of tax	2,834		1,891	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	4,434	(c)	4,600	(c)
Prior service credit	(192)	(c)	(268)	(c)
Total, pre-tax	4,242		4,332	
Tax benefit	(1,635)		(1,689)	
Total, net of tax	2,607		2,643	
Total amounts reclassified, net of tax	$ 5,441		$ 4,534	

(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 our 2016 and 2017 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,” “potential,” “should” 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 Report 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, 2015 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2016 and June 30, 2016), 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.

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 diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	**2016**	**2015**	**2016**	**2015**
PSCo	$ 0.34	$ 0.34	$ 0.74	$ 0.75
NSP-Minnesota	0.41	0.35	0.74	0.65
SPS	0.13	0.12	0.24	0.21
NSP-Wisconsin	0.05	0.05	0.11	0.13
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.04	0.03
Regulated utility	0.94	0.87	1.87	1.77
Xcel Energy Inc. and other	(0.04)	(0.03)	(0.11)	(0.08)
Ongoing diluted EPS	0.90	0.84	1.76	1.69
Loss on Monticello LCM/EPU project	—	—	—	(0.16)
GAAP diluted EPS	**$ 0.90**	**$ 0.84**	**$ 1.76**	**$ 1.53**

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 $0.06 for the third quarter of 2016 and $0.07 per share year-to-date, which excludes the 2015 adjustment for a charge related to the NSP-Minnesota Monticello LCM/EPU project. Electric and natural gas margins rose in the third quarter primarily driven by higher retail electric and natural gas rates and non-fuel riders to recover our capital investments, along with higher sales growth. These positive factors and a lower effective tax rate were offset by higher depreciation, operating and maintenance expenses and interest charges.

PSCo — PSCo's ongoing earnings were flat for the third quarter of 2016 and decreased $0.01 per share year-to-date. Year-to-date, higher natural gas margins, primarily due to rate increases, and higher AFUDC were offset by higher depreciation, O&M expenses and interest charges.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.06 for the third quarter of 2016 and $0.09 per share year-to-date. Year-to-date, higher electric revenues driven by an interim electric rate increase in Minnesota (subject to refund) and non-fuel riders were partially offset by higher depreciation, O&M expenses, interest charges and property taxes.

SPS — SPS' ongoing earnings increased $0.01 for the third quarter of 2016 and $0.03 per share year-to-date. Year-to-date, higher electric margins and lower O&M expenses were partially offset by an increase in depreciation.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings were flat for the third quarter of 2016 and decreased $0.02 per share year-to-date. Year-to-date, the positive impact of higher electric revenues, primarily driven by an electric rate increase, was offset by higher O&M expenses and depreciation.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Ongoing earnings decreased by $0.01 for the third quarter of 2016 and $0.03 per share year-to-date, primarily related to higher long-term debt levels.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2016 EPS compared with the same period in 2015:

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30	Nine Months Ended Sept. 30
2015 GAAP diluted EPS	**$ 0.84**	**$ 1.53**
Loss on Monticello LCM/EPU project	—	0.16
2015 ongoing diluted EPS	**0.84**	**1.69**
Components of change — 2016 vs. 2015		
Higher electric margins [a]	0.14	0.27
Lower ETR	0.02	0.04
Higher natural gas margins [b]	0.01	0.03
Higher depreciation and amortization	(0.06)	(0.17)
Higher interest charges	(0.02)	(0.05)
Higher O&M expenses	(0.03)	(0.03)
Other, net	—	(0.02)
2016 GAAP and ongoing diluted EPS	**$ 0.90**	**$ 1.76**

(a) Reflects $0.006 and $0.015 attributable to weather for the three and nine months ended Sept. 30, 2016, respectively.

(b) Reflects $0.001 and $(0.007) attributable to weather for the three and nine months ended Sept. 30, 2016, respectively.

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 CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. 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 increase (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		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
HDD	(52.6)%	(57.9)%	11.1 %	(12.7)%	(4.2)%	(8.4)%
CDD	11.0	15.1	(3.1)	8.3	5.4	3.3
THI	6.5	4.3	3.2	8.6	(1.6)	11.2

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		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
Retail electric	$ 0.016 [(a)]	$ 0.010	$ 0.006	$ 0.011 [(a)]	$ (0.004)	$ 0.015
Firm natural gas	(0.001)	(0.002)	0.001	(0.014)	(0.007)	(0.007)
Total	$ 0.015	$ 0.008	$ 0.007	$ (0.003)	$ (0.011)	$ 0.008

(a) Excludes $0.008 and $0.009 favorable weather impact due to electric sales decoupling at NSP-Minnesota for the three and nine months ended Sept. 30, 2016, respectively.

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2016 compared to the same period in 2015:

	Three Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	5.6%	4.7 %	1.5%	2.8 %	4.4 %
Electric commercial and industrial	0.1	0.8	3.6	—	1.2
Total retail electric sales	2.0	2.0	3.2	0.7	2.2
Firm natural gas sales	3.5	(5.0)	N/A	(12.8)	(0.2)

	Three Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	4.8 %	2.0 %	1.0%	1.0 %	2.8 %
Electric commercial and industrial	0.5	0.2	3.4	(0.2)	1.0
Total retail electric sales	2.1	0.8	3.1	—	1.6
Firm natural gas sales	(1.6)	(4.9)	N/A	(12.9)	(3.2)

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	4.2 %	1.7 %	(1.7)%	(0.5)%	1.9 %
Electric commercial and industrial	(0.7)	(0.3)	1.6	(0.3)	—
Total retail electric sales	0.9	0.3	1.0	(0.5)	0.6
Firm natural gas sales	3.2	(9.0)	N/A	(12.5)	(1.8)

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	3.4 %	0.6 %	(1.2)%	(0.3)%	1.3 %
Electric commercial and industrial	(0.7)	(0.7)	1.2	(0.4)	(0.3)
Total retail electric sales	0.7	(0.3)	0.8	(0.5)	0.2
Firm natural gas sales	0.9	(0.6)	N/A	(4.7)	—

	Nine Months Ended Sept. 30 (Excluding Leap Day) [b]				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential [a]	3.0 %	0.2 %	(1.6)%	(0.7)%	0.9 %
Electric commercial and industrial	(1.1)	(1.1)	0.8	(0.7)	(0.6)
Total retail electric sales	0.3	(0.7)	0.4	(0.8)	(0.2)
Firm natural gas sales	0.1	(1.4)	N/A	(5.4)	(0.7)

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

(b) The estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 30-40 basis points for retail electric and 70-80 basis points for firm natural gas for the nine months ended Sept. 30, 2016.

Weather-normalized Electric Sales Growth (Decline) — Year-To-Date (Excluding Leap Day)

- PSCo’s residential growth reflects an increased number of customers and higher use per customer. The commercial and industrial (C&I) decline was mainly due to lower sales to certain large customers that support the mining, oil and gas industries. The decline was partially offset by an increase in the number of small C&I customers.
- NSP-Minnesota’s residential sales growth reflects customer additions, partially offset by lower use per customer. C&I sales declined primarily as a result of lower use by small and large customers in the manufacturing industry.
- SPS’ residential sales decline was primarily the result of lower use per customer. The increase in C&I sales was driven by oil and natural gas production in the Southeastern New Mexico, Permian Basin area as well as greater use by agricultural customers.
- NSP-Wisconsin’s residential sales decrease was primarily attributable to lower use per customer, partially offset by customer additions. The C&I decline was largely due to reduced sales to small customers in the sand mining industry. The overall decrease was partially offset by an increase in the number of large and small C&I customers as well as greater use per customer in the large C&I class for the oil and gas industries.

Weather-normalized Natural Gas Sales Decline — Year-To-Date (Excluding Leap Day)

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use, partially offset by a slight increase in the number of customers.

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)	2016	2015	2016	2015
Electric revenues	$ 2,800	$ 2,667	$ 7,209	$ 7,106
Electric fuel and purchased power	(1,037)	(1,015)	(2,755)	(2,870)
Electric margin	$ 1,763	$ 1,652	$ 4,454	$ 4,236

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 2016 vs. 2015	Nine Months Ended Sept. 30 2016 vs. 2015
Retail rate increases [a]	$ 59	$ 132
Transmission revenue	16	53
Estimated impact of weather	11	19
Non-fuel riders	8	16
Retail sales growth, excluding weather impact	18	15
Conservation incentive	7	7
Fuel and purchased power cost recovery	7	(141)
Weather decoupling-Minnesota	(6)	(7)
PSCo earnings test refund	5	(1)
Other, net	8	10
Total increase in electric revenues	$ 133	$ 103

[a] Increase is primarily related to interim rates in Minnesota (subject to and net of estimated provision for refund) and final rates in Wisconsin.

Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2016 vs. 2015	Nine Months Ended Sept. 30 2016 vs. 2015
Retail rate increases [a]	$ 59	$ 132
Estimated impact of weather	11	19
Non-fuel riders	8	16
Retail sales growth, excluding weather impact	18	15
Transmission revenue, net of costs	1	13
Conservation incentive	7	7
Weather decoupling-Minnesota	(6)	(7)
PSCo earnings test refund	5	(1)
Other, net	8	24
Total increase in electric margin	$ 111	$ 218

[a] Increase is primarily due to interim rates in Minnesota (subject to and net of estimated provision for refund) and final rates in Wisconsin.

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 for sales to retail customers, fluctuations in the cost of natural gas has minimal impact 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)	2016	2015	2016	2015
Natural gas revenues	$ 222	$ 216	$ 1,047	$ 1,216
Cost of natural gas sold and transported	(68)	(66)	(470)	(665)
Natural gas margin	$ 154	$ 150	$ 577	$ 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 2016 vs. 2015	Nine Months Ended Sept. 30 2016 vs. 2015
Purchased natural gas adjustment clause recovery	$ (3)	$ (200)
Retail rate increases [(a)]	8	32
Other, net	1	(1)
Total increase (decrease) in natural gas revenues	$ 6	$ (169)

(a) Increase is primarily related to final rates in Colorado.

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2016 vs. 2015	Nine Months Ended Sept. 30 2016 vs. 2015
Retail rate increases [(a)]	$ 8	$ 32
Estimated impact of weather	—	(5)
Non-fuel riders	(3)	(5)
Other, net	(1)	4
Total increase in natural gas margin	$ 4	$ 26

(a) Increase is primarily related to final rates in Colorado.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $24.0 million, or 4.2 percent, for the third quarter of 2016 and $18.3 million, or 1.0 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. The year-to-date increase was mainly due to additional maintenance activities and storm related costs, which were partially offset by a reduction in the timing and scope of plant outages and discovery work.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses increased $6.6 million, or 11.5 percent, for the third quarter of 2016 and $12.0 million, or 7.3 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to more customer participation in DSM programs which has led to additional customer rebates and increased program implementation costs. Higher conservation and DSM program expenses are generally offset by higher revenues due to recovery mechanisms.

Depreciation and Amortization — Depreciation and amortization increased $48.4 million, or 17.3 percent, for the third quarter of 2016 and $143.2 million, or 17.3 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to capital investments, including Pleasant Valley and Border Wind Farms, reduction of the excess depreciation reserve in Minnesota and the full amortization of the DOE settlement in 2015.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) decreased $5.9 million, or 4.8 percent, for the third quarter of 2016 and increased $11.5 million, or 3.0 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. The year-to-date increase was primarily due to higher property taxes in Minnesota, excluding the impact of the proposed settlement agreement in the Minnesota 2016 multi-year electric rate case.

Interest Charges — Interest charges increased $13.3 million, or 8.7 percent, for the third quarter of 2016 and $43.6 million, or 9.9 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. Increases were related to higher long-term debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $0.6 million for the third quarter of 2016 compared with the same period in 2015. The decrease was primarily due to increased wind production tax and research and experimentation credits in 2016, partially offset by higher pretax earnings in 2016. The ETR was 34.2 percent for the third quarter of 2016 compared with 35.9 percent for the same period in 2015. The lower ETR in 2016 is primarily due to the adjustments referenced above.

Income tax expense increased $39.0 million for the first nine months of 2016 compared with the same period in 2015. The increase in income tax expense was primarily due to higher pretax earnings, partially offset by increased wind production tax and research and experimentation credits. The ETR was 34.5 percent for the first nine months of 2016 compared with 35.8 percent for the same period in 2015. The lower ETR in 2016 is primarily due to the adjustments referenced above.

Public Utility Regulation

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, 2015 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, 2016 and June 30, 2016, appropriately represent, in all material respects, the current status of public utility regulation, and are incorporated herein by reference.

NSP-Minnesota

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

Subsequently, NSP-Minnesota proposed revisions to the Plan, which addressed stakeholder recommendations as well as the Clean Power Plan issued by the EPA. The revised plan was 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 revised plan includes substantial opportunities for NSP-Minnesota ownership of renewable generation, and would result in 63 percent of NSP System energy being carbon-free by 2030 and a 60 percent reduction in carbon emissions from 2005 levels by 2030.

Specific terms of the proposal include:

- The addition of 1,800 MW of wind and 1,400 MW of solar between 2016-2030, including approximately 650 MW of solar from NSP-Minnesota's community solar gardens program by 2020;
- The retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026;
- Partial replacement of Sherco coal generation with a 786 MW natural gas combined cycle unit at the Sherco site to coincide with the Unit 1 retirement;
- The addition of a 230 MW natural gas combustion turbine in North Dakota by the end of 2025;
- Operation of the Monticello and PI nuclear plants through their current license periods in the early 2030's - and a commitment to provide additional information regarding forecasted cost increases at PI through end of licensed life if the MPUC wishes to further explore alternatives to operating PI through its current license periods.

In October 2016, the MPUC verbally approved NSP-Minnesota's plan, with modifications as follows:

- The acquisition of at least 1,000 MW of wind by 2019, with additional acquisitions dependent on considerations such as price, bidder qualifications, rate impact, transmission availability and location;
- The acquisition of 650 MW of solar before 2021 through the community solar gardens program or other acquisitions - and pursuit of additional, cost-effective solar resources if it is in the best interests of its customers;
- Determination of the proper mix of purchased power and Company-owned renewable resources shall be made during the resource acquisition process;
- Retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and a finding that more likely than not, there will be a need for approximately 750 MW of capacity coinciding with the retirement of Sherco Unit 1 in 2026;

- Authorization for NSP-Minnesota to file a petition for a certificate of need to select the resource that best meets the system resource and local reliability needs associated with the retirement of Sherco Unit 1 in 2026;
- Acquisition of no less than 400 MW of additional demand response by 2023; and
- Submission of NSP-Minnesota's next Resource Plan by February 2019.

The MPUC's order on NSP-Minnesota's Resource Plan is expected in late 2016.

Request for Proposal (RFP) — In September 2016, NSP-Minnesota issued a RFP for 1,500 MW of wind generation to be in service by 2020. The RFP requests both PPAs and Build-Own-Transfer proposals. NSP-Minnesota intends to compare self-build options to the RFP bids to ensure that all resource additions are cost-competitive.

In October 2016, NSP-Minnesota submitted a petition for approval to the MPUC of a 750 MW self-build wind farm portfolio. RFP bids were received in October 2016 and will be evaluated in conjunction with the self-build proposal.

An overview of the anticipated RFP schedule is as follows:

- Project proposal selection and negotiation will occur from November 2016 to March 2017;
- An NSP-Minnesota recommendation for proposed wind additions to the MPUC in the first quarter of 2017; and
- MPUC approval is expected by July 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 also offers customer solar programs: a solar production incentive program for rooftop solar, called Solar*Rewards®, and a community solar garden program that provides bill credits to participating subscribers, called Solar*Rewards® Community®. Additionally, the DOC offers the "Made in Minnesota" program, providing incentives for the installation of small solar systems that were manufactured in-state, which generates renewable energy credits for utilities including NSP-Minnesota.

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. The order was appealed to the Minnesota Court of Appeals, which affirmed the MPUC's decision. The decision was subsequently appealed to the Minnesota Supreme Court, which denied the appeal in September 2016, terminating the case.

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, 2015 for further discussion regarding the nuclear generating plants. The circumstances set forth in Nuclear Power Operations and Waste Disposal included in Item 1 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2015 and Nuclear Power Operations included in Item 2 of Xcel Energy Inc.'s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2016 and June 30, 2016, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated herein by reference.

NSP-Wisconsin

2016 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for the nine months ended Sept. 30, 2016 were lower than authorized in rates and outside the two percent annual tolerance band established in the Wisconsin fuel cost recovery rules. 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 $6.6 million through Sept. 30, 2016. 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 2017 NSP-Wisconsin will file a reconciliation of 2016 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-2017.

PSCo

Colorado 2016 Electric Resource Plan — In May 2016, PSCo filed its 2016 Electric Resource Plan which identified approximately 600 MW of additional resources need by the summer of 2023. The CPUC is expected to consider the resource plan in two phases. In the first phase, the CPUC will examine the resource need to address peak demand periods, establish the resource acquisition period and determine modeling parameters used in resource selection for the second phase. The second phase would include solicitation of new resources. PSCo’s base plan, filed in Phase I, addressed various resources including 410 MW of combined cycle generation, 700 MW of combustion turbine generation and approximately 600 MW of customer sited solar generation. Additional scenarios to the plan include adding 600 MW of the Rush Creek Wind Project or 400 MW of wind or utility solar generation.

The key dates in the procedural schedule for the first phase of the Electric Resource Plan are as follows:

- Answer testimony — Dec. 9, 2016;
- Rebuttal testimony — Jan. 17, 2017;
- Hearings — Feb. 1-8, 2017; and
- Statements of position — Feb. 17, 2017.

The second phase of the Electric Resource Plan is anticipated to begin shortly after the conclusion of the first phase.

Rush Creek Wind Ownership Proposal — In May 2016, PSCo filed an application to build, own and operate a 600 MW wind generation facility at Rush Creek for a cost of approximately $1 billion, including transmission investment.

In September 2016, the CPUC approved a settlement between PSCo, the CPUC Staff, the Colorado Office of Consumer Counsel, the Colorado Energy Office and various other parties. This will allow PSCo to commence the project on a timely basis and capture the full production tax credit benefit for customers.

Key terms of the settlement are listed below:

- The Rush Creek project satisfies the reasonable cost standard and is in the public interest;
- The project should be placed in service by Oct. 31, 2018;
- The useful life of the project should be set at 25 years;
- A hard cost-cap on the $1.096 billion investment (which includes the capital investment and allowance for funds used during construction);
- A capital cost sharing mechanism for every $10 million below the cost-cap, with 82.5 percent retained by customers and 17.5 percent retained by PSCo on a net present value basis over the life of the project;
- Amounts retained by PSCo under the capital cost sharing mechanism as well as overall facility revenue requirements may each be reduced for lower than projected long term generating output (i.e., higher degradation); and
- The Pawnee-Daniels transmission line (estimated project cost of $178 million) should be accelerated and operations are expected to begin by October 2019.

PSCo Global Settlement Agreement — In August 2016, PSCo and various intervenors, including small and large customers, state representatives, environmental advocates and solar and energy groups, entered into a global settlement agreement regarding three pending filings with the CPUC, including the Phase II electric rate case (which is related to the rate design portion of the 2015 Electric Rate Case), the Renewable*Connect proposal (formally known as Solar*Connect) and the 2017 Renewable Energy Plan. Key terms of the agreement include that participating customers in the proposed Renewable*Connect program would pay ordinary tariff electric rates in addition to a voluntary tariff solar charge, and receive bill credits related to avoided cost savings for a new 50 MW solar resource. It was also agreed that PSCo’s 2017 Renewable Energy Plan would include 2017 to 2019 acquisition of a total of 225 MW of renewable energy from sources including rooftop solar, solar gardens and recycled energy.

A CPUC decision is expected by December 2016, which would allow PSCo to issue a RFP for the new Renewable*Connect solar facility and implement the 2017 Renewable Energy Plan and the rate design changes of the Phase II electric rate case beginning January 2017.

Joint Dispatch Agreement (JDA) — In February 2016, the FERC approved a JDA between PSCo, Black Hills Colorado Electric Utility Company, LP and Platte River Power Authority. Through the JDA, energy is dispatched to economically serve the combined electric customer loads of the three systems. In circumstances where PSCo is the lowest cost producer, it will sell its excess generation to other JDA counterparties. PSCo proposed with the CPUC that margins on these sales be shared among PSCo and its customers, of which 10 percent would be retained by PSCo. A decision by the CPUC is anticipated in the fourth quarter of 2016. The JDA parties estimate the combined net benefits of the agreement would be approximately $4.5 million, annually. The agreement results in a reduction in total energy costs for the parties, of which approximately $1.4 million would be allocated to PSCo’s customers. As part of the agreement, PSCo will earn a management fee to administer the JDA. We expect operations under the JDA to begin in the fourth quarter of 2016.

Advanced Grid Intelligence and Security — In August 2016, PSCo filed a request with the CPUC to approve a certificate of public convenience and necessity for implementation of its advanced grid initiative. The project incorporates installing advanced meters, implementing a combination of hardware and software applications to allow the distribution system to operate at a lower voltage (integrated volt-var optimization) and installing necessary communications infrastructure to implement this hardware. These major projects are expected to improve customer experience, enhance grid reliability and enable the implementation of new and innovative programs and rate structures. The estimated capital investment for the project is approximately $500 million. PSCo anticipates a CPUC decision by the third quarter of 2017. If approval is received, the project is expected to be completed by 2021.

Decoupling Filing — In July 2016, PSCo filed a request with the CPUC to approve a partial decoupling mechanism for a five year period, effective on Jan. 1, 2017. The proposed decoupling adjustment would allow PSCo to adjust annual revenues based on changes in weather normalized average use per customer for the residential and small C&I classes. The proposed mechanism is intended to improve PSCo’s ability to collect base rate revenues in the event that average use per customer declines as a result of DSM, distributed generation and other energy saving programs. The proposed decoupling mechanism is symmetric and may result in potential refunds to customers if there were an increase in average use per customer. PSCo did not request that revenue be adjusted as a result of weather related sales fluctuations.

In August 2016, a majority of the parties to the PSCo Global Settlement Agreement agreed to limit any future opposition to PSCo’s decoupling proposal to the specifics of design and implementation.

The key dates in the procedural schedule are as follows:

- Direct testimony — Dec. 14, 2016;
- Answer testimony — Jan. 16, 2017;
- Rebuttal and cross answer testimony — Feb. 10, 2017; and
- Hearings — Feb. 21-24, 2017.

A decision is anticipated in the first quarter of 2017.

Boulder, Colo. Municipalization — 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 City of Boulder (Boulder) City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility as premature because costs and system separation plans were not final, but the case was dismissed. PSCo appealed this decision and in September 2016, the Colorado Court of Appeals preserved PSCo’s ability to challenge the utility while vacating the lower court’s decision.

In 2013, the CPUC ruled that Boulder may not be the retail service provider to any PSCo customers located outside Boulder city limits unless Boulder can establish that PSCo is unwilling or unable to serve those customers. The CPUC also ruled that it has jurisdiction over the transfer of any facilities to Boulder that currently serve any customers located outside Boulder city limits and will determine separation matters. The CPUC has declared that Boulder must receive CPUC transfer approval prior to any eminent domain actions. Boulder appealed this ruling to the Boulder District Court. In January 2015, the Boulder District Court affirmed the CPUC decision. The Boulder District Court also dismissed a condemnation action that Boulder had filed. The CPUC must complete the separation plan proceeding before Boulder may refile a condemnation proceeding.

In July 2015, Boulder filed an application with the CPUC requesting approval of its proposed separation plan. In August 2015, PSCo filed a motion to dismiss Boulder’s separation proposal, arguing Boulder’s request was not permissible under Colorado law. In December 2015, the CPUC granted the motion to dismiss the application in part, holding that Boulder had no right to acquire PSCo facilities used exclusively to serve customers located outside Boulder city limits. Other portions of Boulder’s application were not dismissed, but were stayed until Boulder supplemented its application. Boulder filed its amended application in September 2016, and in the application, Boulder estimates it would incur approximately $53 million of costs to separate from the PSCo system.

SPS

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 Kilovolt (KV) Transmission Line — In June 2015, SPS filed a certificate of convenience and necessity (CCN) with the PUCT for the 33-mile Yoakum County to Texas/New Mexico State line portion of this 345 KV line project. The PUCT approved this CCN in March 2016. A CCN for the 111-mile TUCO to Yoakum County substation segment was filed in June 2016. Assuming approval of this CCN, this segment is scheduled to be in service in 2019. A 20-mile CCN for the Texas/New Mexico state line to Hobbs Plant segment is planned to be filed in the fourth quarter of 2016 or early 2017. The estimated project cost for all three segments is approximately $242 million.

Wholesale Customer Participation in Electric Reliability Council of Texas (ERCOT) — In March 2016, the PUCT Staff requested comments on Lubbock Power & Light’s (LP&L’s) proposal to transition a portion of its load (approximately 430 MW on a peak basis) to the ERCOT in June 2019. LP&L’s proposal would result in an approximate seven percent reduction of load in SPS, or a loss of approximately $18 million in wholesale transmission revenue based on 2015 revenue requirements. The remaining portion of LP&L’s load (approximately 170 MW) would continue to be served by SPS. Should LP&L join ERCOT, costs to SPS’ remaining customers would increase as SPS’ transmission costs would be spread across a smaller base of customers.

The PUCT has indicated there will be a two-step process regarding LP&L’s possible transfer to ERCOT. The first step will be a proceeding to determine whether the proposed transfer is in the public interest and to consider certain protections for non-LP&L customers who would be affected by LP&L’s transfer. If the PUCT determines the transfer is in the public interest, the second step will be for LP&L to file a CCN application for transmission facilities to connect with ERCOT. As part of the first process, the PUCT asked SPP and ERCOT to perform reliability and economic studies to better understand the implications of LP&L’s proposal. SPS intends to participate in the PUCT’s processes to protect its customers’ interests.

In May 2016, SPS submitted a filing to the FERC seeking approval to impose an Interconnection Switching Fee (exit fee) associated with LP&L’s proposal. In September 2016, FERC dismissed SPS’ petition without prejudice to refile, finding the petition premature since LP&L has not made a final decision to move to ERCOT and the terms of the transition, if any, have not been determined.

Summary of Recent Federal Regulatory Developments

The Pipeline and Hazardous Materials Safety Administration

Pipeline Safety Act — The Pipeline Safety, Regulatory Certainty, and Job Creation Act (Pipeline Safety Act) requires additional verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. In April 2016, the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) released proposed rules that address this verification requirement along with a number of other significant changes to gas transmission regulations. These changes include requirements around use of automatic or remote-controlled shut-off valves; testing of certain previously untested transmission lines; and expanding integrity management requirements. The Pipeline Safety Act also includes a maximum penalty for violating pipeline safety rules of $2 million per day for related violations.

Xcel Energy continues to analyze the proposed rule changes as they relate to costs, current operations and financial results. PHMSA has indicated that they intend for the rules to go into effect in late 2017 or early 2018.

Xcel Energy has been taking actions that were intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. PSCo and NSP-Minnesota can generally recover costs to comply with the transmission and distribution integrity management programs through the pipeline system integrity adjustment and GUIC riders, respectively.

FERC

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, 2015 and Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2016 and June 30, 2016. 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 — The FERC has adopted a new two-step ROE methodology for electric utilities. The issue of how to apply the new FERC ROE methodology is being contested in various complaint proceedings. There are two ROE complaints against the MISO TOs, which include NSP-Minnesota and NSP-Wisconsin. In September 2016, the FERC issued an order in the first MISO ROE complaint which upheld the initial decision made by the ALJ in December 2015. The second complaint is pending FERC action after issuance of an initial decision by the ALJ in June 2016. FERC is not expected to issue an order in the second litigated MISO ROE complaint proceeding until 2017. See Note 5 to the consolidated financial statements for discussion of the MISO ROE Complaints.

Formula Rate Treatment of Accumulated Deferred Income Taxes (ADIT) — In 2015, NSP-Minnesota, NSP-Wisconsin, SPS and PSCo filed changes to their transmission formula rates and PSCo filed changes to its production formula rate, to comply with IRS guidance regarding how ADIT must be reflected in formula rates using future test years and a true-up. The filings were intended to ensure that NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are in compliance with IRS rules and may continue to use accelerated tax depreciation.

In December 2015, the FERC partially accepted the proposed NSP-Minnesota and NSP-Wisconsin transmission formula rate changes, but rejected changes regarding the treatment of ADIT in the formula rate true-up. In September 2016, FERC issued an order clarifying that NSP-Minnesota and NSP-Wisconsin may incorporate ADIT true-up provisions in their formula rate. However, submission of a new tariff change filing is required to implement the change. NSP-Minnesota and NSP-Wisconsin expect to file a change to their transmission formula rate in the fourth quarter of 2016 and will request a Jan. 1, 2016 effective date.

Golden Spread protested the proposed changes to the SPS transmission formula rate. In April 2016, FERC accepted the SPS and PSCo transmission formula rate and PSCo production formula rate changes, subject to compliance filings. SPS and PSCo submitted the compliance filings in May 2016. In August 2016, FERC approved the PSCo and SPS compliance filings.

SPP and MISO Complaints Regarding RTO Joint Operating Agreement (JOA) — SPP and MISO were involved in a long-running dispute regarding the interpretation of their JOA, which is intended to coordinate RTO operations along the MISO/SPP system boundary. SPP and MISO disagreed over MISO's authority to transmit power between the traditional MISO region in the Midwest and the Entergy system. Several cases were filed with the FERC by MISO and SPP between 2011 and 2014.

In January 2016, the FERC approved a settlement between SPP, MISO and other parties that resolves various disputed matters and provides a defined settlement compensation plan by MISO to SPP. MISO will pay SPP $16 million for the two-year retroactive period (February 2014 to January 2016) and $16 million annually prospectively starting Feb. 1, 2016, subject to a true-up. In January 2016, SPP filed a proposal regarding distribution of the MISO revenues to SPP members, including SPS. In March 2016, the FERC issued an order rejecting one component of the SPP filing, accepting the remainder of the SPP tariff proposal subject to refund. In August 2016, MISO and other parties filed a settlement regarding the April 2014 MISO tariff change filing to recover SPP JOA charges in MISO rates. The settlement is pending FERC approval. NSP-Minnesota and NSP-Wisconsin expect to be able to recover any resulting MISO charges in retail rates. The JOA revenue allocated to SPS under the filed SPP proposal was not expected to be material.

Derivatives, Risk Management and Market Risk

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

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

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

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

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

At Sept. 30, 2016, 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	$ 2,719	$ 6,582	$ 1,500	$ 303	$ 11,104
PSCo	1	461	2	—	—	463
		$ 3,180	$ 6,584	$ 1,500	$ 303	$ 11,567

	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	$ (16)	$ —	$ —	$ —	$ (16)

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)	2016	2015
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 11,040	$ 21,811
Contracts realized or settled during the period	(2,628)	(4,400)
Commodity trading contract additions and changes during period	3,139	(3,169)
Fair value of commodity trading net contract assets outstanding at Sept. 30	$ 11,551	$ 14,242

At Sept. 30, 2016, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.3 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.3 million. 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.

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
2016	$ 0.10	$ 3.00	$ 0.18	$ 0.38	$ 0.05
2015	0.17	3.00	0.23	0.63	0.10

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 87 percent of its 2016 and approximately 13 percent of its 2017 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.

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, 2016 and 2015, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $4.2 million and $0.8 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, 2016, 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, 2016, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $11.7 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $15.9 million. 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.

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, 2016. 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, 2016.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 1.3 percent and 8.0 percent of total assets and liabilities, respectively, measured at fair value at Sept. 30, 2016.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $27.8 million and $3.2 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2016.

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. There were no Level 3 commodity forwards and options held at Sept. 30, 2016.

Liquidity and Capital Resources

Cash Flows

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2016**	**2015**
Cash provided by operating activities	$ 2,413	$ 2,490

Net cash provided by operating activities decreased $77 million for the nine months ended Sept. 30, 2016 compared with the nine months ended Sept. 30, 2015. The decrease was primarily due to timing of customer receipts, refunds and recovery on certain electric and natural gas riders and incentive programs, partially offset by timing of vendor payments and higher net income, excluding amounts related to non-cash operating activities (e.g., depreciation, deferred tax expenses and a charge related to the Monticello LCM/EPU project in 2015).

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2016**	**2015**
Cash used in investing activities	$ (2,206)	$ (2,139)

Net cash used in investing activities increased $67 million for the nine months ended Sept. 30, 2016 compared with the nine months ended Sept. 30, 2015. The increase was primarily attributable to the establishment of rabbi trusts in 2016 and the impact of higher insurance proceeds received in 2015.

(Millions of Dollars)	Nine Months Ended Sept. 30 2016	Nine Months Ended Sept. 30 2015
Cash provided by (used in) financing activities	$ 62	$ (26)

Net cash provided by financing activities was $62 million for the nine months ended Sept. 30, 2016 compared with net cash used in financing activities of $26 million for the nine months ended Sept. 30, 2015, or a change of $88 million. The difference was primarily due to lower repayments of short-term debt, partially offset by higher repayments of long-term debt and dividend payments.

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.

***Capital Expenditures* —** The current estimated base capital expenditure programs of Xcel Energy's operating companies for years 2017 through 2021 are shown in the table below:

	Capital Forecast					
(Millions of Dollars)	2017	2018	2019	2020	2021	2017 - 2021 Total
By Subsidiary						
NSP-Minnesota	$ 1,195	$ 1,170	$ 1,515	$ 1,405	$ 1,220	$ 6,505
PSCo	1,590	1,670	1,190	1,030	980	6,460
SPS	610	570	490	400	450	2,520
NSP-Wisconsin	250	280	250	280	300	1,360
Other	10	10	510	510	500	1,540
Total capital expenditures	$ 3,655	$ 3,700	$ 3,955	$ 3,625	$ 3,450	$ 18,385

	Capital Forecast					
(Millions of Dollars)	2017	2018	2019	2020	2021	2017 - 2021 Total
By Function						
Electric transmission	$ 795	$ 840	$ 750	$ 690	$ 805	$ 3,880
Electric distribution	760	865	950	905	955	4,435
Electric generation	670	685	655	405	485	2,900
Natural gas	400	415	420	420	415	2,070
Renewables	610	555	915	925	500	3,505
Other	420	340	265	280	290	1,595
Total capital expenditures	$ 3,655	$ 3,700	$ 3,955	$ 3,625	$ 3,450	$ 18,385

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, renewable portfolio standards and merger, acquisition and divestiture opportunities. The table above does not include potential expenditures of Xcel Energy's transmission-only subsidiaries.

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. Xcel Energy does not anticipate issuing any equity to fund its capital investment program for 2017-2021. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2017 through 2021 are shown in the table below.

(Millions of Dollars)		
Funding Capital Expenditures		
Cash from Operations*	$	13,465
New Debt**		4,920
Equity		—
2017-2021 Capital Expenditures	$	18,385
Maturing Debt	$	3,550

* Net of dividends.
** Reflects a combination of short and long-term debt.

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the Commodity Futures Trading Commission (CFTC) and the SEC with expanded regulatory authority over derivative and swap transactions. The CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. The de minimis threshold is scheduled to be reduced to $3 billion in 2017. Xcel Energy’s current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that exempt certain derivatives end users from much of the clearing and margin requirements and Xcel Energy’s Board of Directors has renewed the end-user exemption on an annual basis. Xcel Energy is currently meeting all reporting requirements and transaction restrictions.

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 2016, contributions of $125.0 million were made across four of Xcel Energy’s pension plans;
- In 2015, contributions of $90.0 million were made across four of Xcel Energy’s pension plans; and
- For future years, contributions will be made as deemed appropriate based on evaluation of various factors including the funded status of the plans, minimum funding requirements, interest rates and expected investment returns.

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, 2016, approximately $281.7 million of cash was held in these accounts.

Amended Credit Agreements - In June 2016, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements remained at $2.75 billion. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the following exceptions:

- The maturity extended from October 2019 to June 2021.
- The Eurodollar borrowing margins on these lines of credit were reduced to a range of 75 to 150 basis points per year, from a range of 87.5 to 175 basis points per year, based upon applicable long-term credit ratings.
- The commitment fees, calculated on the unused portion of the lines of credit, were reduced to a range of 6 to 22.5 basis points per year, from a range of 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

Xcel Energy Inc., NSP-Minnesota, PSCo, and SPS 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.

Credit Facilities — As of Oct. 24, 2016, 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	$ 263	$ 737	$ —	$ 737
PSCo	700	22	678	1	679
NSP-Minnesota	500	11	489	—	489
SPS	400	5	395	1	396
NSP-Wisconsin	150	37	113	1	114
Total	$ 2,750	$ 338	$ 2,412	$ 3	$ 2,415

(a) These credit facilities expire in June 2021.
(b) Includes outstanding commercial paper and letters of credit.

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

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

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2016	Year Ended Dec. 31, 2015
Borrowing limit	$ 2,750	$ 2,750
Amount outstanding at period end	366	846
Average amount outstanding	477	601
Maximum amount outstanding	609	1,360
Weighted average interest rate, computed on a daily basis	0.77%	0.48%
Weighted average interest rate at period end	0.77	0.82

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.

Xcel Energy Inc. and its utility subsidiaries’ 2017 financing plans reflect the following:

- Xcel Energy Inc. plans to issue approximately $300 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds;
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds;
- PSCo plans to issue approximately $400 million of first mortgage bonds; and
- SPS plans to issue approximately $150 million of first mortgage bonds.

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

- In March, Xcel Energy Inc. issued $400 million of 2.4 percent senior notes due March 15, 2021 and $350 million of 3.3 percent senior notes due June 1, 2025;
- In May, NSP-Minnesota issued $350 million of 3.6 percent first mortgage bonds due May 15, 2046;
- In June, PSCo issued $250 million of 3.55 percent first mortgage bonds due June 15, 2046;
- In August, SPS issued $300 million of 3.4 percent first mortgage bonds due Aug. 15, 2046; and
- Xcel Energy Inc. plans to issue approximately $800 million of senior notes in the fourth quarter.

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

Off-Balance-Sheet Arrangements

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

Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy's revised 2016 ongoing earnings guidance is $2.17 to $2.22 per share, compared with the previous issued guidance of $2.12 to $2.27 per share.[a] Key assumptions related to 2016 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 be relatively flat.
- Capital rider revenue is projected to increase by $35 million to $45 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 1 percent from 2015 levels.
- Depreciation expense is projected to increase approximately $185 million to $195 million over 2015 levels. Approximately $20 million of the increased depreciation expense and amortization will be recovered through the renewable development fund rider (not included in the capital rider) in Minnesota.
- Property taxes are projected to increase approximately $20 million to $25 million over 2015 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $50 million to $60 million over 2015 levels.
- AFUDC — equity is projected to increase approximately $0 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.

Xcel Energy's 2017 ongoing earnings guidance is $2.25 to $2.35 per share.[a] Key assumptions related to 2017 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase 0 percent to 0.5 percent.
- Weather-normalized retail firm natural gas sales are projected to increase 0 percent to 0.5 percent.
- Capital rider revenue is projected to increase by $65 million to $75 million over 2016 levels.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately $160 million to $170 million over 2016 levels.
- Property taxes are projected to increase approximately $0 million to $10 million over 2016 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $5 million to $15 million over 2016 levels.
- AFUDC — equity is projected to increase approximately $10 million to $20 million from 2016 levels.
- The ETR is projected to be approximately 32 percent to 34 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

(a) Given the unplanned and/or unknown nature of adjustments that may be necessary to reconcile ongoing diluted EPS to GAAP diluted EPS, Xcel Energy is unable to provide a quantitative reconciliation of the guidance for ongoing diluted EPS to corresponding GAAP diluted EPS.

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 ongoing 2015 EPS of $2.10;
- 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, 2016, 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

Effective January 2016, Xcel Energy implemented the general ledger modules of a new enterprise resource planning (ERP) system to improve certain financial and related transaction processes. During 2016 and 2017, Xcel Energy will continue implementing additional modules and expects to begin conversion of existing work management systems to this new ERP system. In connection with this ongoing implementation, Xcel Energy has updated and will continue updating its internal control over financial reporting, as necessary, to accommodate modifications to its business processes and accounting procedures. Xcel Energy does not expect the implementation of the additional modules to materially affect its internal control over financial reporting.

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are 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 a 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, 2015, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended Sept. 30, 2016:

	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, 2016 — July 31, 2016	—	$ —	—	—
Aug. 1, 2016 — Aug. 31, 2016 [(a)]	47,802	42.22	—	—
Sept. 1, 2016 — Sept. 30, 2016	—	—	—	—
Total	47,802		—	—

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

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

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Item 6 — EXHIBITS

* Indicates incorporation by reference
+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Xcel Energy Inc. Bylaws, as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K dated Feb. 17, 2016 (file no. 001-03034)).
4.01*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300,000,000 principal amount of 3.40 percent First Mortgage Bonds, Series No. 4 due 2046. (Exhibit 4.02 to Form 8-K of SPS dated Aug. 12, 2016 (file no. 001-03789)).
10.01+	Third Amendment dated Sept. 30, 2016 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2016 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. 28, 2016	By:	/s/ JEFFREY S. SAVAGE
		Jeffrey S. Savage Senior Vice President, Controller (Principal Accounting Officer)
		/s/ ROBERT C. FRENZEL
		Robert C. Frenzel Executive Vice President, Chief Financial Officer (Principal Financial Officer)

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Section 2: EX-10.01 (EXHIBIT 10.01)

Exhibit 10.01

THIRD AMENDMENT
TO THE
XCEL ENERGY INC. NON-QUALIFIED DEFERRED COMPENSATION PLAN

2009 Restatement

WHEREAS, Xcel Energy Inc. (the “Employer”) established the Xcel Energy Inc. Non-Qualified Deferred Compensation Plan (the “Plan”) for the benefit of its eligible employees; and

WHEREAS, the Employer now wishes to amend the Plan to provide for additional diversification of deferred Long-Term Incentive Awards granted to eligible employees;

NOW, THEREFORE, the Plan is hereby amended, effective November 1, 2016, as follows:

1. **Section 1.2.18A is amended to read as follows:**

1.2.18A Long-Term Incentive Award - An award granted under the Xcel Energy Inc. 2005 Long-Term Incentive Plan, as amended and restated from time to time, or any successor plan thereto, other than an Option, Stock Appreciation Right or other form of award thereunder that is recognized by the Committee as an Annual Incentive Bonus for purposes of this Plan.

2. **Section 1.2.18B is amended to read as follows:**

1.2.18B Long-Term Incentive Deferral Subaccount - the account, if any, maintained for a Participant to which are credited deferrals of Long-Term Incentive Awards payable to the Participant. For purposes of this Section, a Long-Term Incentive Award may be considered “performance-based compensation” if the award is based on services performed over a period of at least twelve months and meets the definition of “performance-based compensation” found in Code Section 409A and the regulations issued thereunder.

3. **Section 2.1.2 is amended to read as follows:**

Each Participant may elect to make contributions to the Plan by filing a deferral election with the Committee by such date as the Committee shall prescribe, which date shall (a) as to Base Salary, Annual Incentive Bonus and Long-Term Incentive Award deferrals, be no later than December 31 of the Plan Year prior to the beginning of the Plan Year to which such election is to apply, except that (b) if the Annual Incentive Bonus or Long-Term Incentive Award is determined by the Committee to be “performance-based compensation” within the meaning of Treasury Regulation §1.409A-2(a)(8), the Committee may permit such election to be made no later than six months before the end of the performance period to which such election relates, and (c) the Committee may permit such election to be made within 30 days of the grant date of a Long-Term Incentive Award if the terms of such Award satisfy the requirements of Treasury Regulation §1.409A-2(a)(5). Participants who are classified by the Employer as “Section 16 Officers” (as such term is defined by rules promulgated by the Securities and Exchange Commission) or as “Business Unit Vice Presidents” and above will be eligible for deferrals of Long-Term Incentive Awards. The Administrator, or to the extent authority has been delegated to the Committee, the Administrator or the Committee reserves such discretion to add additional classes of Participants who are eligible for deferrals of Long-Term Incentive Awards.

4. **Subparagraph (c) of Section 3.1.1 is amended to read as follows:**

(c) Long-Term Incentive Award Deferrals. For each Plan Year, any Participant authorized to do so in accordance with Section 2.1.2 may elect to make a pre-tax deferral of all or part of any Long-Term Incentive Award granted to such Participant.

5. **Subparagraph (f) of Section 3.3 is amended to read as follows:**

(f) Long-Term Incentive Award Deferrals. Within a reasonable time following the date that the amount of a Long-Term Incentive Award elected by a Participant to be deferred would otherwise be paid to such Participant, the Employer shall credit the Participant's Long-Term Incentive Deferral Subaccount with such amount. The Employer will create such additional separate sub-accounts as is necessary to distinguish between the portion of the Long-Term Incentive Deferral Subaccount that is required to be invested in the Company Stock Fund pursuant to Section 3.4.1 and the portion no longer subject to such limitation.

6. **Section 3.4.1 is amended by inserting the following new last sentence:**

Notwithstanding the foregoing, if payment of all or any portion of a Long-Term Incentive Award is deferred, the deemed investment of the deferred amount shall be required to be made in the Investment Fund consisting of common stock of the Principal Sponsor (the "Company Stock Fund") for the greater of (i) six months from the date of deferral or (ii) such period following the date of deferral as is specified in the Principal Sponsor's stock ownership guidelines for officers. Following such period, the Participant is permitted to elect to diversify into any other permitted Investment Fund in accordance with the provisions of Section 3.4.2.

7. Subparagraph (b) of Section 3.4.3 is amended by deleting the sentences that had been added to that subparagraph by the Second Amendment to the Plan, effective May 21, 2013 (the "Second Amendment").

8. Section 3.4.4 is deleted in its entirety.

9. Section 3.4.5 is deleted in its entirety.

10. Section 5.7.2 is amended to read as follows:

5.7.2 Change in Control. Each Participant's Account shall be paid to him in a single cash lump sum within 90 days of the occurrence of an effective change in ownership or effective change in control of his or her Employer, or a change in the ownership of a substantial portion of the assets of his or her Employer, as such terms are defined and in a manner consistent with the provisions of Code §409A and Treasury Regulation § 1.409A-3(i)(5). Valuation of the portion of the Participant's Account consisting of phantom shares of common stock of the Company will be valued at the price of a share of the Sponsor's common stock on the effective date of a change in control.

11. Section 5.9 is amended by deleting the sentences that had been added to that Section by the Second Amendment.

IN WITNESS WHEREOF, the Employer has caused this Amendment to be executed this 30th day of September, 2016.

XCEL ENERGY INC.

By: /s/ MARVIN E. MCDANIEL, JR

Marvin E. McDaniel, Jr

Title: Executive Vice President, Group President, Utilities and Chief Administrative Officer

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Section 3: EX-31.01 (EXHIBIT 31.01)

Exhibit 31.01

CERTIFICATION

I, Ben Fowke, certify that:

1. I have reviewed this report on Form 10-Q of Xcel Energy Inc. (a Minnesota corporation);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Oct. 28, 2016

/s/ BEN FOWKE

Ben Fowke
Chairman, President, Chief Executive Officer and Director
(Principal Executive Officer)

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Section 4: EX-31.02 (EXHIBIT 31.02)

Exhibit 31.02

CERTIFICATION

I, Robert C. Frenzel, certify that:

1. I have reviewed this report on Form 10-Q of Xcel Energy Inc. (a Minnesota corporation);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Oct. 28, 2016

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

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Section 5: EX-32.01 (EXHIBIT 32.01)

Exhibit 32.01

OFFICER CERTIFICATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Xcel Energy Inc. (Xcel Energy) on Form 10-Q for the quarter ended Sept. 30, 2016, as filed with the SEC on the date hereof (Form 10-Q), each of the undersigned officers of Xcel Energy certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Xcel Energy as of the dates and for the periods expressed in the Form 10-Q.

Date: Oct. 28, 2016

/s/ BEN FOWKE

Ben Fowke
Chairman, President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ ROBERT C. FRENZEL

Robert C. Frenzel
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Xcel Energy and will be retained by Xcel Energy and furnished to the SEC or its staff upon request.

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Section 6: EX-99.01 (EXHIBIT 99.01)

Exhibit 99.01

XCEL ENERGY CAUTIONARY FACTORS

The Private Securities Litigation Reform Act provides a "safe harbor" for forward-looking statements to encourage disclosures without the threat of litigation, providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements are made in written documents and oral presentations of Xcel Energy Inc. or any of its subsidiaries. These statements are based on management's beliefs as well as assumptions and information currently available to management. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause Xcel Energy's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;
- The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;
- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where Xcel Energy has a financial interest;
- Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the FERC and similar entities with regulatory oversight;
- Availability or cost of capital such as changes in: interest rates; market perceptions of the utility industry, Xcel Energy Inc. or any of its subsidiaries; or security ratings;
- Factors affecting utility and nonutility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel, nuclear fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; nuclear or environmental incidents; cyber incidents; or electric transmission or natural gas pipeline constraints;
- Employee workforce factors, including loss or retirement of key executives, collective-bargaining agreements with union employees, or work stoppages;
- Increased competition in the utility industry or additional competition in the markets served by Xcel Energy Inc. and its subsidiaries;
- State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric and natural gas markets; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Environmental laws and regulations, including legislation and regulations relating to climate change, and the associated cost of compliance;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;
- Nuclear regulatory policies and procedures, including operating regulations and spent nuclear fuel storage;
- Social attitudes regarding the utility and power industries;
- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;
- Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;
- Risks associated with implementations of new technologies; and
- Other business or investment considerations that may be disclosed from time to time in Xcel Energy Inc.'s SEC filings, including "Risk Factors" in Item 1A of Xcel Energy's Form 10-K for the year ended Dec. 31, 2015, or in other publicly disseminated written documents.

Xcel Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exhaustive.

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