XCEL ENERGY INC
Form 10-Q
October 27, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended Sept. 30, 2017
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File Number: 001-3034
Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota	41-0448030
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
414 Nicollet Mall	
Minneapolis, Minnesota	55401
(Address of principal executive offices)	(Zip Code)

(612) 330-5500
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨
(Do not check if smaller reporting company)	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

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

Class	Outstanding at October 23, 2017
Common Stock, $2.50 par value	507,762,881 shares

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This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. and its consolidated subsidiaries are also referred to herein as Xcel Energy. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin, which is operated on an integrated basis and is managed by NSP-Minnesota, is referred to collectively as the NSP System. Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

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PART I — FINANCIAL INFORMATION

Item 1 — FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)
(amounts in thousands, except per share data)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2017	2016	2017	2016
Operating revenues				
Electric	$2,783,569	$2,799,964	$7,420,646	$7,209,225
Natural gas	214,253	221,956	1,129,795	1,046,544
Other	19,075	18,227	57,806	56,500
Total operating revenues	3,016,897	3,040,147	8,608,247	8,312,269
Operating expenses				
Electric fuel and purchased power	1,006,160	1,037,263	2,850,480	2,755,083
Cost of natural gas sold and transported	63,998	67,566	543,452	469,754
Cost of sales — other	8,451	8,648	25,216	25,225
Operating and maintenance expenses	541,539	590,009	1,706,102	1,764,397
Conservation and demand side management expenses	73,728	63,914	206,121	177,266
Depreciation and amortization	371,091	328,503	1,102,015	971,057
Taxes (other than income taxes)	133,571	117,190	410,591	400,982
Total operating expenses	2,198,538	2,213,093	6,843,977	6,563,764
Operating income	818,359	827,054	1,764,270	1,748,505
Other income, net	5,089	578	14,143	6,388
Equity earnings of unconsolidated subsidiaries	7,080	9,701	22,496	32,500
Allowance for funds used during construction — equity	23,483	17,199	54,182	45,042
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,923, $6,060, $17,657 and $19,026, respectively	167,803	165,857	497,932	485,280
Allowance for funds used during construction — debt	(10,724)	(7,532)	(25,359)	(20,206)
Total interest charges and financing costs	157,079	158,325	472,573	465,074
Income before income taxes	696,932	696,207	1,382,518	1,367,361
Income taxes	204,791	238,412	423,844	471,459
Net income	$492,141	$457,795	$958,674	$895,902
Weighted average common shares outstanding:				
Basic	508,581	508,941	508,468	508,840
Diluted	509,242	509,566	509,052	509,396
Earnings per average common share:				

Basic	$0.97	$0.90	$1.89	$1.76
Diluted	0.97	0.90	1.88	1.76
Cash dividends declared per common share	$0.36	$0.34	$1.08	$1.02

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2017	2016	2017	2016
Net income	$492,141	$457,795	$958,674	$895,902
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $582, $536, $1,805 and $1,635, respectively	982	878	2,886	1,954
Derivative instruments:				
Net fair value increase (decrease), net of tax of $15, $(2), $32 and $3, respectively	23	(4)	49	4
Reclassification of losses to net income, net of tax of $587, $588, $1,632 and $1,786, respectively	981	960	2,609	2,834
	1,004	956	2,658	2,838
Marketable securities:				
Net fair value increase, net of tax of $0, $0, $0 and $0, respectively	—	—	1	—
Other comprehensive income	1,986	1,834	5,545	4,792
Comprehensive income	$494,127	$459,629	$964,219	$900,694

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

	Nine Months Ended Sept. 30	
	2017	2016
Operating activities		
Net income	$958,674	$895,902
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	1,113,418	982,682
Conservation and demand side management program amortization	1,927	3,089
Nuclear fuel amortization	87,654	89,475
Deferred income taxes	501,013	479,100
Amortization of investment tax credits	(3,835)	(3,920)
Allowance for equity funds used during construction	(54,182)	(45,042)
Equity earnings of unconsolidated subsidiaries	(22,496)	(32,500)
Dividends from unconsolidated subsidiaries	32,316	34,502
Share-based compensation expense	44,239	29,872
Net realized and unrealized hedging and derivative transactions	(62)	3,307
Other, net	(2,577)	(266)
Changes in operating assets and liabilities:		
Accounts receivable	(31,337)	(29,585)
Accrued unbilled revenues	104,175	87,015
Inventories	(9,158)	(6,203)
Other current assets	64,208	80,566
Accounts payable	(67,759)	50,526
Net regulatory assets and liabilities	(26,556)	3,911
Other current liabilities	(111,512)	(63,524)
Pension and other employee benefit obligations	(134,455)	(96,350)
Change in other noncurrent assets	(15,002)	(11,815)
Change in other noncurrent liabilities	(61,513)	(25,401)
Net cash provided by operating activities	2,367,180	2,425,341
Investing activities		
Utility capital/construction expenditures	(2,256,452)	(2,186,483)
Proceeds from insurance recoveries	—	1,595
Allowance for equity funds used during construction	54,182	45,042
Purchases of investment securities	(971,469)	(390,031)
Proceeds from the sale of investment securities	948,558	327,378
Investments in WYCO Development LLC and other	(7,616)	(3,962)
Other, net	(5,803)	204
Net cash used in investing activities	(2,238,600)	(2,206,257)
Financing activities		
Proceeds from (repayments of) short-term borrowings, net	122,000	(480,000)
Proceeds from issuances of long-term debt	1,422,163	1,632,642
Repayments of long-term debt, including reacquisition premiums	(1,030,099)	(580,167)
Repurchases of common stock	(2,943)	(2,810)

Dividends paid	(538,045)	(507,817)
Other	(18,291)	(12,487)
Net cash (used in) provided by financing activities	(45,215)	49,361
Net change in cash and cash equivalents	83,365	268,445
Cash and cash equivalents at beginning of period	84,476	84,940
Cash and cash equivalents at end of period	$167,841	$353,385
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(488,574)	$(461,302)
Cash received for income taxes, net	42,051	61,245
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$268,932	$221,155
Issuance of common stock for equity awards	23,394	17,527

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

	Sept. 30, 2017	Dec. 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$167,841	$84,476
Accounts receivable, net	807,621	776,289
Accrued unbilled revenues	625,657	729,832
Inventories	616,675	604,226
Regulatory assets	407,639	363,655
Derivative instruments	74,533	38,224
Prepaid taxes	55,788	106,697
Prepayments and other	143,120	138,682
Total current assets	2,898,874	2,842,081
Property, plant and equipment, net	33,949,952	32,841,750
Other assets		
Nuclear decommissioning fund and other investments	2,300,265	2,091,858
Regulatory assets	3,011,462	3,080,867
Derivative instruments	49,124	50,189
Other	259,117	248,532
Total other assets	5,619,968	5,471,446
Total assets	$42,468,794	$41,155,277
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$305,415	$255,529
Short-term debt	514,000	392,000
Accounts payable	992,498	1,044,959
Regulatory liabilities	256,191	220,894
Taxes accrued	427,275	457,392
Accrued interest	147,860	172,901
Dividends payable	182,795	172,456
Derivative instruments	27,659	26,959
Other	486,713	503,953
Total current liabilities	3,340,406	3,247,043
Deferred credits and other liabilities		
Deferred income taxes	7,362,931	6,784,319
Deferred investment tax credits	59,381	63,216
Regulatory liabilities	1,358,558	1,383,212
Asset retirement obligations	2,883,799	2,782,229
Derivative instruments	131,058	148,146
Customer advances	190,995	195,214

Pension and employee benefit obligations	984,794	1,112,366
Other	144,528	223,965
Total deferred credits and other liabilities	13,116,044	12,692,667
Commitments and contingencies		
Capitalization		
Long-term debt	14,572,967	14,194,718
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 507,762,881 and 507,222,795 shares outstanding at Sept. 30, 2017 and Dec. 31, 2016, respectively	1,269,407	1,268,057
Additional paid in capital	5,888,729	5,881,494
Retained earnings	4,386,050	3,981,652
Accumulated other comprehensive loss	(104,809)	(110,354)
Total common stockholders’ equity	11,439,377	11,020,849
Total liabilities and equity	$42,468,794	$41,155,277

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended Sept. 30, 2017 and 2016						
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
Repurchases of common stock	(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
Balance at June 30, 2017	507,763	$1,269,407	$5,881,475	$4,079,068	$ (106,795)	$11,123,155
Net income				492,141		492,141
Other comprehensive income					1,986	1,986
Dividends declared on common stock				(184,061)		(184,061)
Share-based compensation			7,254	(1,098)		6,156
Balance at Sept. 30, 2017	507,763	$1,269,407	$5,888,729	$4,386,050	$ (104,809)	$11,439,377

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

	Common Stock Issued				Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Other Comprehensive Loss	Common Stockholders' Equity
Nine Months Ended Sept. 30, 2017 and 2016						
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
Repurchases of common stock	(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
Balance at Dec. 31, 2016	507,223	$1,268,057	$5,881,494	$3,981,652	$ (110,354)	$11,020,849
Net income				958,674		958,674
Other comprehensive income					5,545	5,545
Dividends declared on common stock				(551,614)		(551,614)
Issuances of common stock	611	1,527	3,510			5,037
Repurchases of common stock	(71)	(177)	(2,943)			(3,120)
Share-based compensation			6,668	(2,662)		4,006
Balance at Sept. 30, 2017	507,763	$1,269,407	$5,888,729	$4,386,050	$ (104,809)	$11,439,377

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

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of Sept. 30, 2017 and Dec. 31, 2016; 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, 2017 and 2016; and its cash flows for the nine months ended Sept. 30, 2017 and 2016. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2017 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, 2016 balance sheet information has been derived from the audited 2016 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2016. 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, 2016, filed with the SEC on Feb. 24, 2017. 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, 2016, 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 new framework for the recognition of revenue. Xcel Energy expects its adoption will primarily result in increased disclosures regarding revenue related to arrangements with customers, as well as separate presentation of alternative revenue programs. Xcel Energy currently expects to implement the standard on a modified retrospective basis, which requires application to contracts with customers effective Jan. 1, 2018, with the cumulative impact on contracts not yet completed as of Dec. 31, 2017 recognized as an adjustment to the opening balance of retained earnings.

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 eliminates the available-for-sale classification for marketable equity securities and also replaces the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Under the new standard, 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 expects that as a result of application of accounting principles for rate regulated entities, changes in the fair value of the securities in the nuclear decommissioning fund, currently classified as available-for-sale, will continue to be deferred to a regulatory asset, and that the overall impacts of the

Jan. 1, 2018 adoption will not be material.

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 most leases. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018. Xcel Energy has not yet fully determined the impacts of implementation. However, adoption is expected to occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard. As such, agreements entered prior to Jan. 1, 2017 that are currently considered leases are expected to be recognized on the consolidated balance sheet, including contracts for use of office space, equipment and natural gas storage assets, as well as certain purchased power agreements (PPAs) for natural gas-fueled generating facilities. Xcel Energy expects that similar agreements entered after Dec. 31, 2016 will generally qualify as leases under the new standard, but has not yet completed its evaluation of certain other contracts, including arrangements for the secondary use of assets, such as land easements.

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Presentation of Net Periodic Benefit Cost — In March 2017, the FASB issued Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07), which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. Xcel Energy expects that as a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the current ratemaking treatment and that the impacts of adoption will be limited to changes in classification of non-service costs in the consolidated statement of income. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2017.

Recently Adopted

Stock Compensation — In March 2016, the FASB issued Improvements to Employee Share-Based Payment Accounting, Topic 718 (ASU No. 2016-09), which simplifies accounting and financial statement presentation for share-based payment transactions. The guidance requires that the difference between the tax deduction available upon settlement of share-based equity awards and the tax benefit accumulated over the vesting period be recognized as an adjustment to income tax expense. Xcel Energy adopted the guidance in 2016, resulting in immaterial 2016 adjustments to income tax expense and changes in classification of cash flows related to tax withholding in the consolidated statements of cash flows for the years ended Dec. 31, 2016, 2015 and 2014.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Accounts receivable, net		
Accounts receivable	$859,242	$827,112
Less allowance for bad debts	(51,621)	(50,823)
	$807,621	$776,289

(Thousands of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Inventories		
Materials and supplies	$320,195	$312,430
Fuel	166,173	181,752
Natural gas	130,307	110,044
	$616,675	$604,226

(Thousands of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Property, plant and equipment, net		
Electric plant	$39,067,098	$38,220,765
Natural gas plant	5,563,536	5,317,717
Common and other property	2,028,743	1,888,518
Plant to be retired [(a)]	11,412	31,839
Construction work in progress	1,861,576	1,373,380
Total property, plant and equipment	48,532,365	46,832,219
Less accumulated depreciation	(14,982,709)	(14,381,603)
Nuclear fuel	2,668,586	2,571,770
Less accumulated amortization	(2,268,290)	(2,180,636)
	$33,949,952	$32,841,750

(a) In the third quarter of 2017, PSCo early retired Valmont Unit 5 and converted 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.

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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, 2016 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal 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 Audits — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2009 through 2011 and 2012 through 2013 federal income tax returns, following extensions, expires in June 2018 and October 2018, respectively.

In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback claims that would have resulted in $14 million of income tax expense for the 2009 through 2011 claims, and the 2013 through 2015 claims. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals). In the third quarter of 2017, Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). After evaluating the proposed adjustment, Xcel Energy filed a protest with the IRS. Xcel Energy anticipates the issue will be forwarded to Appeals. As of Sept. 30, 2017, Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

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, 2017, 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 2016, Minnesota began an audit of years 2010 through 2014. As of Sept. 30, 2017, Minnesota had not proposed any material adjustments;
- In 2016, Texas began an audit of years 2009 and 2010, and, in September 2017, began an audit of 2011. As of Sept. 30, 2017, Texas had not proposed any material adjustments;
- In 2016, Wisconsin began an audit of years 2012 and 2013. As of Sept. 30, 2017, Wisconsin had not proposed any material adjustments; and
- As of Sept. 30, 2017, there were no other state income tax audits in progress.

Unrecognized Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual 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, 2017	Dec. 31, 2016
Unrecognized tax benefit — Permanent tax positions	$ 20.6	$ 29.6
Unrecognized tax benefit — Temporary tax positions	22.2	104.1
Total unrecognized tax benefit	$ 42.8	$ 133.7

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The unrecognized tax benefit amounts were reduced by the tax benefits associated with 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, 2017	Dec. 31, 2016
NOL and tax credit carryforwards	$(29.2)	$(43.8)

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 progresses and audits resume, the Minnesota, Texas and Wisconsin audits progress, and other state audits resume. As the IRS Appeals, Minnesota, Texas and Wisconsin audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $19 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits are as follows:

(Millions of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Payable for interest related to unrecognized tax benefits at beginning of period	$(3.4)	$(0.1)
Interest income (expense) related to unrecognized tax benefits recorded during the period	1.9	(3.3)
Payable for interest related to unrecognized tax benefits at end of period	$(1.5)	$(3.4)

No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2017 or Dec. 31, 2016.

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, 2016 and in Note 5 to Xcel Energy Inc.'s Quarterly Report on
Form 10-Q for the quarterly periods ended March 31, 2017 and June 30, 2017, 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 June 2017, the MPUC issued a written order. NSP-Minnesota estimated the total rate increase to be approximately $245 million over the four-year period covering 2016-2019.

Key terms:
- Four-year period covering 2016-2019;
- Annual sales true-up with decoupling subject to a 3 percent cap;
- Return on equity (ROE) of 9.2 percent and an equity ratio of 52.5 percent;
- Nuclear related costs will not be considered provisional;
- Continued use of all existing riders, however no new riders may be utilized during the four-year term;
- Deferral of incremental 2016 property tax expense above a fixed threshold to 2018 and 2019;
- Four-year stay-out provision for rate cases;

- Property tax true-up mechanism for 2017-2019; and
- Capital expenditure true-up mechanism for 2016-2019.

(Millions of Dollars, Incremental)	2016	2017	2018	2019	Total
Revenues	$74.99	$59.86	$ —	$50.12	$184.97
NSP-Minnesota's sales true-up	59.95	—	—	(0.20)	59.75
Total rate impact	$134.94	$59.86	$ —	$49.92	$244.72

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In September 2017, the MPUC ordered NSP-Minnesota to collect final rates beginning March 1, 2017 (requested date was Jan. 1, 2017). As a result, NSP-Minnesota estimates the adjusted total rate increase to be approximately $240 million over the four-year period covering 2016-2019.

Annual Automatic Adjustment of Fuel Clause Charges — In May 2017, the MPUC voted to disallow approximately $4.4 million of replacement energy costs for the Prairie Island (PI) nuclear facility outages allocated to the Minnesota jurisdiction in 2015. This disallowance was recognized in the second quarter of 2017. In September 2017, the Minnesota Department of Commerce (DOC) recommended the MPUC should hold utilities responsible for incremental costs of replacement power incurred due to unplanned outages under certain circumstances. In addition, the DOC is continuing its review of nuclear costs and operations focusing on PI under the initial rate case and resource plan orders as well as the recently finalized rate case.

NSP-Wisconsin

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

Wisconsin 2018 Electric and Natural Gas Rate Case — In May 2017, NSP-Wisconsin filed a request with the PSCW to increase electric rates by $24.7 million, or 3.6 percent, and natural gas rates by $12.0 million, or 10.1 percent, effective Jan. 1, 2018. The rate filing is based on a 2018 forecast test year, a ROE of 10.0 percent, an equity ratio of 52.53 percent and a forecasted rate base of approximately $1.2 billion for the electric utility and $138.4 million for the natural gas utility.

In September 2017, the PSCW Staff and the intervenors filed testimony. The PSCW Staff recommended an electric rate increase of $10.9 million, or 1.6 percent, and a natural gas rate increase of $9.9 million, or 8.3 percent, based on a ROE of 9.8 percent and an equity ratio of 51.45 percent.

A PSCW decision is anticipated in December 2017 with new rates effective in January 2018.

PSCo

Pending Regulatory Proceedings — Colorado Public Utilities Commission (CPUC)

Colorado 2017 Multi-Year Electric Rate Case — In October 2017, PSCo filed a multi-year request with the CPUC seeking to increase electric rates approximately $245 million over four years. The request, summarized below, is based on forecast test years (FTY) ending Dec. 31, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	2018	2019	2020	2021	Total
Revenue request	$74.6	$74.9	$59.7	$35.7	$244.9
Clean Air Clean Jobs Act (CACJA) revenue conversion to base rates (a)	90.4	—	—	—	90.4
Transmission Cost Adjustment (TCA) revenue conversion to base rates (a)	42.7	—	—	—	42.7
Total (b)	$207.7	$74.9	$59.7	$35.7	$378.0
Expected year-end rate base (billions of dollars) (b)	$6.8	$7.1	$7.3	$7.4	

(a) The roll-in of each of the TCA and CACJA rider revenues into base rates will not have an impact on total customer bills or total revenue as these costs are already being recovered through a rider. Transmission investments for 2019 through 2021 will be recovered through the TCA rider.

(b)

This base rate request does not include the impacts associated with the renewable energy standard adjustment and retail electric commodity adjustment for the Rush Creek wind investments or any impacts of the proposed Colorado Energy Plan.

Final rates are expected to be effective in June 2018. PSCo also proposed a stay-out provision and earnings test through 2021.

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Colorado 2017 Multi-Year Natural Gas Rate Case — In June 2017, PSCo filed a multi-year request with the CPUC seeking to increase retail natural gas rates approximately $139 million over three years. The request, detailed below, is based on FTYs, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	2018	2019	2020	Total
Revenue request	$63.2	$32.9	$42.9	$139.0
Pipeline System Integrity Adjustment (PSIA) revenue conversion to base rates [a]	—	93.9	—	93.9
Total	$63.2	$126.8	$42.9	$232.9
Expected year-end rate base (billions of dollars) [b]	$1.5	$2.3	$2.4	

(a) The roll-in of PSIA rider revenue into base rates will not have an impact on customer bills or total revenue as these costs are already being recovered through the rider. PSCo plans to request new PSIA rates for 2018 in November 2017. The recovery of incremental PSIA related investments in 2019 and 2020 are included in the base rate request.

(b) The additional rate base in 2019 predominantly reflects the roll-in of capital associated with the PSIA rider.

In October 2017, several parties filed answer testimony. The CPUC Staff (Staff) and the Office of Consumer Counsel (OCC), recommended a single 2016 historic test year (HTY), based on an average 13-month rate base, and opposed a multi-year plan (MYP). The Staff and OCC recommended an equity capital structure of 48.73 percent and 51.2 percent, respectively. Both the Staff and the OCC recommended the existing PSIA rider expire with the 2018 rates rolled into base rates beginning Jan. 1, 2019. Planned investments in 2019 and 2020 would be recoverable through base rates, subject to a future rate case.

The following represents adjustments to PSCo's filed request made by Staff and OCC for 2018:

(Millions of Dollars)	Staff	OCC
Filed 2018 new revenue request	$63.2	$63.2
Impact of the change in test year	4.4	4.4
PSCo's filed 2016 HTY	$67.6	$67.6
Recommended adjustments:		
ROE (9.0 percent)	(13.5)	(13.5)
Capital structure and cost of debt	(10.2)	(7.5)
Change in amortization period	(5.4)	—
Prepaid pension and retiree medical assets	(5.2)	—
Change from 2016 year end to average rate base	(4.8)	(4.8)
Other, net	(5.0)	(5.5)
Total adjustments	$(44.1)	$(31.3)
Total recommended rate increase	$23.5	$36.3

The next steps in the procedural schedule are as follows:

- Rebuttal testimony — Nov. 3, 2017;
- Intervenor sur-rebuttal testimony — Nov. 15, 2017;
- Hearings — Dec. 11 - 15 and 18 - 19, 2017; and
- Statements of position — Jan. 19, 2018.

Interim rates, subject to refund, are expected to be effective Jan. 1, 2018. A final decision by the CPUC is anticipated in March 2018.

Annual Electric Earnings Test — PSCo must share with customers earnings that exceed the authorized ROE of 9.83 percent for 2015 through 2017, as part of an annual earnings test. The current estimate of the 2017 earnings test, based on annual forecasted information, did not result in the recognition of a liability as of Sept. 30, 2017.

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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 $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. In March 2017, the Travis County District Court denied SPS' appeal. In April 2017, SPS appealed the District Court's decision to the Court of Appeals.

Texas 2017 Electric Rate Case — In August 2017, SPS filed a $66.4 million, or 7.1 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the PUCT. The request was based on the 12-month period ended June 30, 2017, with the final three months based on estimates, a requested ROE of 10.25 percent, a Texas retail electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent.

In October 2017, SPS revised its request to $54.6 million, or 5.8 percent, which reflects updated actual results. In addition, approximately $4.4 million of rate case expenses was bifurcated into a separate docket.

The following table summarizes SPS' revised rate increase request:

Revenue Request (Millions of Dollars)	
Incremental revenue request	$69.2
Transmission Cost Recovery Factor (TCRF) revenue conversion to base rates [a]	(14.6)
Net revenue increase request	$54.6

(a) The roll-in of the TCRF rider revenue into base rates will not have an impact on customer bills or total revenue as these costs are already being recovered through the rider. SPS can request another TCRF rider after the conclusion of this rate case to recover transmission investments subsequent to June 30, 2017.

Key dates in the procedural schedule are as follows:

- Intervenors' direct testimony — Feb. 22, 2018;
- PUCT Staff direct testimony — March 1, 2018;
- PUCT Staff and intervenors' cross-rebuttal testimony — March 22, 2018;
- SPS' rebuttal testimony — March 23, 2018;
- Hearings — April 10 - 20, 2018; and
- Statutory deadline — Aug. 31, 2018.

The final rates are expected to be effective retroactive to Jan. 23, 2018 through a customer surcharge. A PUCT decision is expected in the third quarter of 2018.

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

New Mexico 2016 Electric Rate Case — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $41.4 million, representing a total revenue increase of approximately 10.9 percent. The rate filing was based on a requested ROE of 10.1 percent, an equity ratio of 53.97 percent, an electric rate base of approximately $832 million and a future test year ending June 30, 2018.

In April 2017, the NMPRC dismissed SPS' rate case. In May 2017, SPS filed a notice of appeal to the New Mexico Supreme Court. A decision from the New Mexico Supreme Court is not expected until the second or third quarter of 2018.

SPS plans to file another base rate case by November 2017 utilizing a HTY ending June 2017.

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Pending Regulatory Proceeding — Federal Energy Regulatory Commission (FERC)

Midcontinent Independent System Operator, Inc. (MISO) ROE Complaints — 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, and the removal of ROE adders (including those for Regional Transmission Organization (RTO) membership), effective Nov. 12, 2013.

In December 2015, an administrative law judge (ALJ) recommended the FERC approve a base ROE of 10.32 percent for the MISO TOs. The ALJ found the existing 12.38 percent ROE to be unjust and unreasonable. The recommended 10.32 percent ROE applied a FERC ROE policy adopted in a June 2014 order (Opinion 531). The FERC approved the ALJ recommended 10.32 percent base ROE in an order issued in September 2016. This ROE would be 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 would be 10.82 percent, including a 50 basis point adder for RTO membership. Various parties requested rehearing of the September 2016 order. The requests are pending FERC action.

In February 2015, a second complaint seeking to reduce the MISO ROE from 12.38 percent to 8.67 percent prior to any adder was filed with the FERC, resulting in a second period of potential refund from Feb. 12, 2015 to May 11, 2016. In June 2016, the ALJ recommended a ROE of 9.7 percent, applying the methodology adopted by the FERC in Opinion 531. A final FERC decision on the second ROE complaint was expected later in 2017, but in April 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) by opinion, vacated and remanded Opinion 531. It is unclear how the D.C. Circuit's opinion to vacate and remand Opinion 531 will affect the September 2016 FERC order or the timing and outcome of the second ROE complaint. The MISO TOs are evaluating the impact of the D.C. Circuit ruling on the November 2013 and February 2015 ROE complaints. In September 2017, certain MISO TOs (not including NSP-Minnesota and NSP-Wisconsin) filed a motion to dismiss the second ROE complaint. The motion to dismiss is pending FERC action.

As of Sept. 30, 2017, NSP-Minnesota has processed the refunds for the Nov. 12, 2013 to Feb. 11, 2015 complaint period based on the 10.32 percent ROE provided in the September 2016 FERC order. NSP-Minnesota has also recognized a current refund liability consistent with the best estimate of the final ROE for the Feb. 12, 2015 to May 11, 2016 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 from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In July 2016, the FERC granted SPP's request for a waiver to allow SPP to recover the charges not billed since 2008. In November 2016, SPP billed SPS a net amount, for the period from 2008 through August 2016, of $12.8 million for these charges, to be paid over a five-year period commencing November 2016. SPP is also billing SPS ongoing charges of approximately $0.5 million per month. On the retail level, in October 2016, SPS filed applications for deferred accounting and future recovery of related costs in New Mexico and Texas. In December 2016, SPS' New Mexico application was consolidated with its base rate case, but the NMPRC dismissed that rate case in April 2017. SPS will seek recovery of these SPP charges in its next New Mexico base rate case by November 2017. In March 2017, SPS withdrew its Texas application and is now seeking to recover these SPP charges in its pending rate case filed in August 2017.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed on and after November 2016 asserting that SPP has assessed upgrade charges to SPS even where SPS' transmission service was not dependent upon the upgrade as required by the SPP OATT. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings. Also in October 2017, SPP made adjustments to its previous calculations of upgrade charges to SPP customers, and the impact was immaterial to SPS.

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, 2016, 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, 2017 and June 30, 2017 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.

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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 megawatts (MW) of capacity under long-term PPAs as of Sept. 30, 2017 and Dec. 31, 2016, 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, 2017 and Dec. 31, 2016, 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, 2017	Dec. 31, 2016
Guarantees issued and outstanding	$19.1	$ 18.8
Current exposure under these guarantees	—	0.1
Bonds with indemnity protection	51.9	43.0

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 Manufactured Gas Plant (MGP) Site — NSP-Wisconsin was 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.

In 2012, NSP-Wisconsin agreed to remediate the Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site), under a settlement agreement with the United States Environmental Protection Agency (EPA). In January 2017, NSP-Wisconsin agreed to remediate the Phase II Project Area (the Sediments), under a settlement agreement with the EPA. The settlement was approved by the U.S. District Court for the Western District of Wisconsin. NSP-Wisconsin initiated field activities to perform a full scale wet dredge remedy of the Sediments in 2017 and anticipates completion of restoration activities in 2018.

The current remediation cost estimate for the entire site (both the Phase I Project Area and the Sediments) is approximately $162.9 million, of which approximately $131.8 million has been spent. As of Sept. 30, 2017 and Dec. 31, 2016, NSP-Wisconsin had recorded a total liability of $31.1 million and $64.3 million, respectively, for the entire site.

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NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has 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 May 2017, NSP-Wisconsin filed a natural gas rate case which included recovery of additional expenses associated with remediating the Site. If approved, the annual recovery of MGP clean-up costs would increase from $12.4 million in 2017 to $18.1 million in 2018.

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 and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). NSP-Minnesota has recommended that targeted source removal of impacted soils and historic MGP infrastructure should be performed. The North Dakota Department of Health approved NSP-Minnesota’s proposed cleanup plan in January 2017. It is anticipated that remediation activities will be performed in 2018, although the timing and final scope of remediation is dependent on whether reasonable access is provided to NSP-Minnesota to perform and implement the approved cleanup plan. Access agreements have been reached with a majority of the property owners in the area to perform the work. NSP-Minnesota has also 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 January 2018.

As of Sept. 30, 2017 and Dec. 31, 2016, NSP-Minnesota had recorded a liability of $16.2 million and $11.3 million, respectively, for the Fargo MGP Site. The current cost estimate for the remediation of the site is approximately $23.0 million, of which approximately $6.8 million has been spent. In December 2015, the North Dakota Public Service Commission (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 approximately 12 percent allocable to the Minnesota jurisdiction. Uncertainties related to the liability recognized include obtaining access to perform the approved remediation (including the prospective purchase of the historic MGP property), and the potential for contributions from entities that may be identified as PRPs.

Other MGP and Landfill Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP and landfill sites. Xcel Energy has identified eleven sites across its service territories in addition to the sites in Ashland, Wis. and Fargo, N.D., where former MGP or landfill disposal activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these sites, there are other parties that may have responsibility for some portion of any remediation. Xcel Energy anticipates that the majority of the investigation or remediation at these sites will continue through at least 2018. Xcel Energy had accrued $4.5 million and $2.0 million for these sites as of Sept. 30, 2017 and Dec. 31, 2016, respectively. There may be insurance recovery and/or recovery from other PRPs to offset any costs incurred. Xcel Energy anticipates that any significant amounts incurred will be recovered from customers.

Environmental Requirements

Water and Waste

Federal Clean Water Act (CWA) Waters of the United States Rule — In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) published a final rule that significantly expanded the types of water bodies regulated under the CWA and broadened the scope of waters subject to federal jurisdiction. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule and subsequently ruled that it, rather than the federal district courts, had jurisdiction over challenges to the rule. In January 2017, the U.S. Supreme Court agreed to resolve the dispute as to which court should hear challenges to the rule. A ruling is expected in the first quarter of 2018.

In February 2017, President Trump issued an executive order requiring the EPA and the Corps to review and revise the final rule. On June 27, 2017, the agencies issued a proposed rule that rescinds the 2015 final rule and reinstates the prior 1986 definition of “Water of the U.S.” The agencies are also undertaking a rulemaking to develop a new definition of “Waters of the U.S.”

Federal CWA Effluent Limitations Guidelines (ELG) — In 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. In September 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport water until November 2020 while the agency conducts a rulemaking process to potentially revise the effluent limitations and pretreatment standards for these waste streams.

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Air

Greenhouse Gas (GHG) Emission Standard for Existing Sources (Clean Power Plan or CPP) — In 2015, the EPA issued its final rule for existing power plants. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA’s state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets.

The CPP was challenged by multiple parties in the D.C. Circuit Court. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. In September 2016, the D.C. Circuit Court heard oral arguments in the consolidated challenges to the CPP. The stay will remain in effect until the D.C. Circuit Court reaches its decision and the U.S. Supreme Court either declines to review the lower court’s decision or reaches a decision of its own.

In March 2017, President Trump signed an executive order requiring the EPA Administrator to review the CPP rule and if appropriate, publish proposed rules suspending, revising or rescinding it. Accordingly, the EPA has requested that the D.C. Circuit Court hold the litigation in abeyance until the EPA completes its work under the executive order. The D.C. Circuit granted the EPA’s request and is holding the litigation in abeyance, while considering briefs by the parties on whether the court should remand the challenges to the EPA rather than holding them in abeyance, determining whether and how the court continues or ends the stay that currently applies to the CPP.

In October 2017, the EPA published a proposed rule to repeal the CPP, based on an analysis that the CPP exceeds the EPA’s statutory authority under the Clean Air Act (CAA). The EPA will take public comment on the proposal for 60 days. The EPA stated it has not yet determined whether it will promulgate a new rule to regulate GHG emissions from existing electric generating units.

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. The Best Available Retrofit Technology (BART) requirements of the EPA’s regional haze rules 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 Sulfur Dioxide (SO_2), Nitrogen Oxide (NOx) and particulate matter 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, Cross-State Air Pollution Rule (CSAPR). The requirements of the regional haze plans developed by Minnesota and Colorado that apply to NSP-Minnesota and PSCo have been fully approved and implemented in those states. States are required to revise their plans every ten years. The next plans for Minnesota and Colorado will be due in 2021. Texas’ first regional haze plan has undergone federal review as described below.

BART Determinations for Texas: Texas developed a State Implementation Plan (SIP) that found the CAIR equal to BART for electric generating units. As a result, no additional controls beyond CAIR compliance would have been required. In 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 deferred its approval of CSAPR compliance as BART until the EPA considered further adjustments to CSAPR emission budgets under the D.C. Circuit Court’s remand of the Texas SO_2 emission budgets. The EPA then published a proposed rule in January 2017 that could have had the effect of requiring installation of dry scrubbers to reduce SO_2 emissions from Harrington Units 1 and 2. Investment costs associated with dry scrubbers for Harrington Units 1 and 2 could have been approximately $400 million. In September 2017, the EPA issued a final rule adopting a Texas only SO_2 trading program as a BART Alternative. The program allocated SO_2 allowances to electric generating units in Texas, including all three Harrington units and both Tolk units, consistent with their allocation under CSAPR, resulting in an emissions budget for Texas that is consistent with the EPA’s 2012 rule. SPS expects the allowance allocations to be sufficient for SO_2 emissions from Harrington and Tolk units in 2019 and future years. The anticipated costs of compliance are not expected to have a material impact on the results of operations, financial position or cash flows; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Reasonable Progress Rule: In January 2016, the EPA adopted a final rule establishing a federal implementation plan 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. SPS appealed the EPA’s decision and requested a stay of the final rule. The United States Court of Appeals for the Fifth Circuit (Fifth Circuit) granted the stay. In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, while leaving the stay in effect. The Fifth Circuit is now holding the case in abeyance until the EPA completes its reconsideration of the rule. In the final BART rule that affects Tolk and Harrington described above, the EPA noted that it will address the remanded rule in a future action. Such a rule will address whether further SO_2 emission reductions are needed at Tolk to address the “reasonable progress” requirements of the regional haze program. The risk of these controls being imposed along with the risk of investments to provide additional cooling water to Tolk have caused SPS to seek to decrease the remaining depreciable life of the Tolk units.

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Revisions to the National Ambient Air Quality Standard (NAAQS) for Ozone — In 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where Xcel Energy operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota and meet the 70 ppb level in the Texas panhandle. In documents issued with the new standard, the EPA projects that both areas will meet the new standard. The Denver Metropolitan Area is currently not meeting the prior ozone standard and will therefore not meet the new, more stringent standard, however PSCo's scheduled retirement of coal fired plants in Denver that began in 2011 and was completed in August 2017, should help in any plan to mitigate non-attainment. In August 2017, the EPA withdrew its prior decision delaying designations of nonattainment areas under the 2015 ozone NAAQS to October 2018. The CAA requires areas to be designated within two years after a revision to the NAAQS but allows a one year extension if the EPA has insufficient information on which to base a decision. The EPA is now re-assessing to what extent it has sufficient information to make designations in October 2017 and whether in some cases an extension is still necessary.

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

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.

e prime, Xcel Energy and its other affiliates were sued along with several other gas marketing companies. These cases were all consolidated in the U.S. District Court in Nevada. Six of the cases remain active, which includes one multi-district litigation (MDL) matter consisting of a Colorado class (Breckenridge), a Wisconsin class (Arandell Corp.), a Missouri class, a Kansas class, and two other cases identified as "Sinclair Oil" and "Farmland." A motion for class certification was denied and plaintiffs have appealed the ruling to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). Motions for summary judgment were granted by the MDL judge in favor of e prime and Xcel Energy in Sinclair Oil and Farmland. Plaintiffs in both cases appealed this decision to the Ninth Circuit. Motions for summary judgment were also filed by defendants, including e prime, in all of the remaining lawsuits. These motions were denied and e prime subsequently filed an appeal in September 2017. Dates for all matters pending before the Ninth Circuit have not been scheduled. 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 and gas service agreements entered into by PSCo and various developers. The dispute involves 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 CPUC. In June 2016, DRC appealed the district court’s dismissal of the lawsuit, and the Colorado Court of Appeals affirmed the lower court decision in favor of PSCo. In July 2017, DRC filed a petition to appeal the decision with the Colorado Supreme Court. It is uncertain whether the Colorado Supreme Court will grant the petition. 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 the Denver District Court in August 2016. In July 2017, a stipulation to dismiss this lawsuit with prejudice was filed on behalf of all parties and granted by the Denver District Court.

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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, 2017	Year Ended Dec. 31, 2016
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	514	392
Average amount outstanding	679	485
Maximum amount outstanding	867	1,183
Weighted average interest rate, computed on a daily basis	1.50 %	0.74 %
Weighted average interest rate at period end	1.53	0.95

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, 2017 and Dec. 31, 2016, there were $28 million and $19 million, respectively, of letters of credit outstanding under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

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

As of Sept. 30, 2017, 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	$ 422	$ 578
PSCo	700	4	696
NSP-Minnesota	500	21	479

SPS	400	3	397
NSP-Wisconsin	150	92	58
Total	$ 2,750	$ 542	$ 2,208

(a) These credit facilities expire in June 2021.

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

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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 as of Sept. 30, 2017 and Dec. 31, 2016.

Long-Term Borrowings

During 2017, Xcel Energy Inc. and its utility subsidiaries issued the following:

- PSCo issued $400 million of 3.80 percent first mortgage bonds due June 15, 2047;
- SPS issued $450 million of 3.70 percent first mortgage bonds due Aug. 15, 2047; and
- NSP-Minnesota issued $600 million of 3.60 percent first mortgage bonds due Sept. 15, 2047.

Debt Redemption

- On Aug. 30, 2017, SPS reacquired $250 million of debt with a coupon rate of 8.75 percent and an original maturity date of Dec. 1, 2018. The redemption resulted in payment of an early redemption premium of $21.6 million which was deferred as a regulatory asset.
- On Sept. 29, 2017, NSP-Minnesota reacquired $500 million of debt with a coupon rate of 5.25 percent and an original maturity date of March 1, 2018. The redemption resulted in payment of an early redemption premium of $7.9 million which was deferred as a regulatory asset.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

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

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

Specific valuation methods include the following:

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

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds 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.

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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 classification. 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, generally 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 transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. The valuation process for FTRs utilizes the cleared prices for each FTR for the most recent auction.

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 transparency in the auction process, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements 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, the limited transparency associated with the 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 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. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were $511.7 million and $378.6 million as of Sept. 30, 2017 and Dec. 31, 2016, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $10.3 million and $46.9 million as of Sept. 30, 2017 and Dec. 31, 2016, respectively.

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The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund as of Sept. 30, 2017 and Dec. 31, 2016:

	Sept. 30, 2017					
		Fair Value				
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV [b]	Total
Nuclear decommissioning fund [a]						
Cash equivalents	$32,727	$32,727	$—	$ —	$ —	$32,727
Commingled funds:						
Non U.S. equities	257,487	204,502	—	—	86,654	291,156
Emerging market debt funds	97,285	—	—	—	106,842	106,842
Private equity investments	139,185	—	—	—	192,098	192,098
Real estate	129,219	—	—	—	195,506	195,506
Other commingled funds	146,179	14,964	—	—	145,313	160,277
Debt securities:						
Government securities	45,310	—	44,944	—	—	44,944
U.S. corporate bonds	251,138	—	252,868	—	—	252,868
Non U.S. corporate bonds	46,245	—	46,611	—	—	46,611
Equity securities:						
U.S. equities	258,075	509,564	—	—	—	509,564
Non U.S. equities	152,575	224,139	—	—	—	224,139
Total	$1,555,425	$985,896	$344,423	$ —	$ 726,413	$2,056,732

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $131.8 million of equity investments in unconsolidated subsidiaries and $111.7 million of rabbi trust assets and miscellaneous investments.

(b) Due to limited availability of published pricing and a lack of immediate redeemability, certain fund investments measured at NAV are not required to be categorized within the fair value hierarchy.

	Dec. 31, 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	$20,379	$20,379	$—	$ —	$ —	$20,379
Commingled funds:						
Non U.S. equities	260,877	133,126	—	—	112,233	245,359
Emerging market debt funds	93,597	—	—	—	97,543	97,543
Commodity funds	106,571	—	—	—	92,091	92,091
Private equity investments	132,190	—	—	—	190,462	190,462
Real estate	128,630	—	—	—	187,647	187,647
Other commingled funds	151,048	—	—	—	159,489	159,489
Debt securities:						
Government securities	32,764	—	31,965	—	—	31,965
U.S. corporate bonds	104,913	—	105,772	—	—	105,772
Non U.S. corporate bonds	21,751	—	21,672	—	—	21,672
Municipal bonds	13,609	—	13,786	—	—	13,786
Mortgage-backed securities	2,785	—	2,816	—	—	2,816

Equity securities:						
U.S. equities	270,779	473,400	—	—	—	473,400
Non U.S. equities	189,100	218,381	—	—	—	218,381
Total	$1,528,993	$845,286	$176,011	$ —	$ 839,465	$1,860,762

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $132.8 million of equity investments in unconsolidated subsidiaries and $98.3 million of rabbi trust assets and miscellaneous investments.

(b) Due to limited availability of published pricing and a lack of immediate redeemability, certain fund investments measured at NAV are not required to be categorized within the fair value hierarchy.

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For the three and nine months ended Sept. 30, 2017 and 2016 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, as of Sept. 30, 2017:

	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	$—	$1,275	$2,303	$41,366	$44,944
U.S. corporate bonds	3,834	64,119	150,741	34,174	252,868
Non U.S. corporate bonds	—	13,793	26,651	6,167	46,611
Debt securities	$3,834	$79,187	$179,695	$81,707	$344,423

Rabbi Trusts

In June 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan. The following tables present the cost and fair value of the assets held in rabbi trusts as of Sept. 30, 2017 and Dec. 31, 2016:

	Sept. 30, 2017				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$11,227	$11,227	$ —	$ —	$11,227
Mutual funds	46,368	48,944	—	—	48,944
Total	$57,595	$60,171	$ —	$ —	$60,171

	Dec. 31, 2016				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$47,831	$47,831	$ —	$ —	$47,831
Mutual funds	1,663	1,901	—	—	1,901
Total	$49,494	$49,732	$ —	$ —	$49,732

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

Derivative Instruments Fair Value Measurements

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

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

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As of Sept. 30, 2017, accumulated other comprehensive losses related to interest rate derivatives included $2.6 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, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy’s risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

As of Sept. 30, 2017, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2018. Xcel Energy enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be 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, 2017 and 2016.

As of Sept. 30, 2017, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs as of Sept. 30, 2017 and Dec. 31, 2016:

(Amounts in Thousands) [a][b]	Sept. 30, 2017	Dec. 31, 2016
Megawatt hours of electricity	78,733	46,773
Million British thermal units of natural gas	62,279	121,978
Gallons of vehicle fuel	300	—

[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.

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The following tables detail the impact of derivative activity during the three and nine months ended Sept. 30, 2017 and 2016, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2017				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$1,579 [a]	$—	$—
Vehicle fuel and other commodity	38	—	(11) [b]	—	—
Total	$38	$—	$1,568	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$1,282 [c]
Electric commodity	—	17,750	—	(3,122) [d]	—
Natural gas commodity	—	(2,076)	—	—	—
Total	$—	$15,674	$—	$(3,122)	$1,282

	Nine Months Ended Sept. 30, 2017				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$4,257 [a]	$—	$—
Vehicle fuel and other commodity	81	—	(16) [b]	—	—
Total	$81	$—	$4,241	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$8,069 [c]
Electric commodity	—	17,245	—	(9,435) [d]	—
Natural gas commodity	—	(9,921)	—	1,075 [e]	(4,070) [e]
Total	$—	$7,324	$—	$(8,360)	$3,999

Three Months Ended Sept. 30, 2016

(Thousands of Dollars)	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
	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

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(Thousands of Dollars)	Nine Months Ended Sept. 30, 2016 Pre-Tax Fair Value Gains (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 Gains (Losses) Recognized During the Period in Income
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)

(a) Amounts are recorded to interest charges.

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

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

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses 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) Certain derivatives are utilized to mitigate natural gas price risk for electric generation and are 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, 2017 included no settlement gains or losses and $0.9 million of settlement gains, respectively. Amounts for the three and nine months ended Sept. 30, 2016 included no settlement gains or losses. The remaining derivative settlement gains and losses for the three and nine months ended Sept. 30, 2017 and 2016 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 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, 2017 and 2016. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty’s ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy’s own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy Inc. and its subsidiaries employ additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. As of Sept. 30, 2017, three of Xcel Energy's 10 most significant counterparties for these activities, comprising $36.1 million or 22 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Six of the 10 most significant counterparties, comprising $44.2 million or 27 percent of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. The one remaining significant counterparty, comprising of $8.1 million or 5 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external analysis. Nine of these significant counterparties are municipal or cooperative electric entities or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including 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's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies or for cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of Sept. 30, 2017 and Dec. 31, 2016, there were no derivative instruments in a material liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Sept. 30, 2017 and Dec. 31, 2016.

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 as of Sept. 30, 2017:

	Sept. 30, 2017					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$56	$—	$56	$ —	$56
Other derivative instruments:						
Commodity trading	1,412	12,172	86	13,670	(6,692)	6,978
Electric commodity	—	—	62,951	62,951	(2,841)	60,110
Natural gas commodity	—	1,898	—	1,898	(135)	1,763
Total current derivative assets	$1,412	$14,126	$63,037	$78,575	$ (9,668)	68,907
PPAs [(a)]						5,626
Current derivative instruments						$74,533
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$11	$—	$11	$ —	$11
Other derivative instruments:						
Commodity trading	84	30,613	5,661	36,358	(7,574)	28,784
Total noncurrent derivative assets	$84	$30,624	$5,661	$36,369	$ (7,574)	28,795
PPAs [(a)]						20,329

Noncurrent derivative instruments	$49,124

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(Thousands of Dollars)	Sept. 30, 2017 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$1,289	$10,204	$3	$11,496	$ (7,495)	$4,001
Electric commodity	—	—	2,842	2,842	(2,841)	1
Natural gas commodity	—	962	—	962	(135)	827
Total current derivative liabilities	$1,289	$11,166	$2,845	$15,300	$ (10,471)	4,829
PPAs [(a)]						22,830
Current derivative instruments						$27,659
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$52	$23,072	$—	$23,124	$ (10,239)	$12,885
Total noncurrent derivative liabilities	$52	$23,072	$—	$23,124	$ (10,239)	12,885
PPAs [(a)]						118,173
Noncurrent derivative instruments						$131,058

(a) 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, 2017. At Sept. 30, 2017, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $3.5 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis as of Dec. 31, 2016:

(Thousands of Dollars)	Dec. 31, 2016 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$13,179	$14,105	$—	$27,284	$ (20,637)	$6,647
Electric commodity	—	—	19,251	19,251	(1,976)	17,275
Natural gas commodity	—	8,839	—	8,839	—	8,839
Total current derivative assets	$13,179	$22,944	$19,251	$55,374	$ (22,613)	32,761
PPAs [(a)]						5,463
Current derivative instruments						$38,224
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$100	$31,029	$—	$31,129	$ (7,323)	$23,806
Natural gas commodity	—	1,652	—	1,652	—	1,652
Total noncurrent derivative assets	$100	$32,681	$—	$32,781	$ (7,323)	25,458
PPAs [(a)]						24,731

Noncurrent derivative instruments	$50,189

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	Dec. 31, 2016 Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$13,787	$11,320	$22	$25,129	$ (20,974)	$4,155
Electric commodity	—	—	1,976	1,976	(1,976)	—
Total current derivative liabilities	$13,787	$11,320	$1,998	$27,105	$ (22,950)	4,155
PPAs [a]						22,804
Current derivative instruments						$26,959
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$89	$23,424	$—	$23,513	$ (10,727)	$12,786
Total noncurrent derivative liabilities	$89	$23,424	$—	$23,513	$ (10,727)	12,786
PPAs [a]						135,360
Noncurrent derivative instruments						$148,146

(a) 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, 2016. At Dec. 31, 2016, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $3.7 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, 2017 and 2016:

	Three Months Ended Sept. 30	
(Thousands of Dollars)	2017	2016
Balance at July 1	$69,237	$24,517
Purchases	—	274
Settlements	(33,144)	(33,982)
Net transactions recorded during the period:		
Gains recognized in earnings [a]	548	9
Net gains recognized as regulatory assets and liabilities	29,212	33,777
Balance at Sept. 30	$65,853	$24,595

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2017	2016
Balance at Jan. 1	$17,253	$18,028
Purchases	80,073	33,296
Settlements	(75,121)	(60,707)

Net transactions recorded during the period:		
Gains (losses) recognized in earnings [a]	5,769	(33)
Net gains recognized as regulatory assets and liabilities	37,879	34,011
Balance at Sept. 30	$65,853	$24,595

[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, 2017 and 2016.

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Fair Value of Long-Term Debt

As of Sept. 30, 2017 and Dec. 31, 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Sept. 30, 2017		Dec. 31, 2016	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$14,878,382	$16,192,542	$14,450,247	$15,513,209

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, 2017 and Dec. 31, 2016, 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)	2017	2016	2017	2016
Interest income	$5,772	$1,385	$11,679	$6,439
Other nonoperating income	—	341	5,013	2,517
Insurance policy expense	(528)	(1,148)	(2,549)	(2,568)
Other nonoperating expense	(155)	—	—	—
Other income, net	$5,089	$578	$14,143	$6,388

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 $131.8 million and $132.8 million as of Sept. 30, 2017 and Dec. 31, 2016, 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.

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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, 2017					
Operating revenues from external customers	$2,783,569	$214,253	$19,075	$ —	$3,016,897
Intersegment revenues	351	378	—	(729)	—
Total revenues	$2,783,920	$214,631	$19,075	$ (729)	$3,016,897
Net income (loss)	$503,058	$1,853	$(12,770)	$ —	$492,141

(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
Nine Months Ended Sept. 30, 2017					
Operating revenues from external customers	$7,420,646	$1,129,795	$57,806	$ —	$8,608,247
Intersegment revenues	1,081	927	—	(2,008)	—
Total revenues	$7,421,727	$1,130,722	$57,806	$ (2,008)	$8,608,247
Net income (loss)	$924,773	$77,946	$(44,045)	$ —	$958,674

(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

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 a dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards.

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

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

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

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

	Three Months Ended Sept. 30, 2017			Three Months Ended Sept. 30, 2016		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$492,141	—	—	$457,795	—	—
Basic EPS:						
Earnings available to common shareholders	492,141	508,581	$ 0.97	457,795	508,941	$ 0.90
Effect of dilutive securities:						
Time based equity awards	—	661	—	—	625	—
Diluted EPS:						
Earnings available to common shareholders	$492,141	509,242	$ 0.97	$457,795	509,566	$ 0.90

	Nine Months Ended Sept. 30, 2017			Nine Months Ended Sept. 30, 2016		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$958,674	—	—	$895,902	—	—
Basic EPS:						
Earnings available to common shareholders	958,674	508,468	$ 1.89	895,902	508,840	$ 1.76
Effect of dilutive securities:						
Time based equity awards	—	584	—	—	556	—
Diluted EPS:						
Earnings available to common shareholders	$958,674	509,052	$ 1.88	$895,902	509,396	$ 1.76

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2017	2016	2017	2016
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$23,547	$22,940	$465	$432
Interest cost	36,702	40,027	5,984	6,527
Expected return on plan assets	(52,318)	(52,575)	(6,155)	(6,249)
Amortization of prior service credit	(442)	(478)	(2,672)	(2,672)
Amortization of net loss	26,671	24,384	1,672	1,011

Net periodic benefit cost (credit)	34,160	34,298	(706)	(951)
Costs not recognized due to the effects of regulation	(3,610)	(3,976)	—	—
Net benefit cost (credit) recognized for financial reporting	$30,550	$30,322	$(706)	$(951)

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(Thousands of Dollars)	Nine Months Ended Sept. 30 2017	2016	2017	2016
	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$70,641	$68,805	$1,395	$1,295
Interest cost	110,106	120,078	17,952	19,580
Expected return on plan assets	(156,953)	(157,725)	(18,466)	(18,746)
Amortization of prior service credit	(1,326)	(1,439)	(8,015)	(8,015)
Amortization of net loss	80,012	73,154	5,016	3,031
Net periodic benefit cost (credit)	102,480	102,873	(2,118)	(2,855)
Costs not recognized due to the effects of regulation	(11,523)	(12,587)	—	—
Net benefit cost (credit) recognized for financial reporting	$90,957	$90,286	$(2,118)	$(2,855)

In January 2017, contributions of $150.0 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2017.

13. Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive (loss) income, net of tax, for the three and nine months ended Sept. 30, 2017 and 2016 were as follows:

(Thousands of Dollars)	Three Months Ended Sept. 30, 2017 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 June 30	$(49,497)	$ 111	$ (57,409)	$(106,795)
Other comprehensive income before reclassifications	23	—	—	23
Losses reclassified from net accumulated other comprehensive loss	981	—	982	1,963
Net current period other comprehensive income	1,004	—	982	1,986
Accumulated other comprehensive (loss) income at Sept. 30	$(48,493)	$ 111	$ (56,427)	$(104,809)

(Thousands of Dollars)	Three Months Ended Sept. 30, 2016 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 June 30	$(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)

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2017 Gains and Losses on Cash Flow	Unrealized Gains on Marketable Securities	Defined Benefit Pension and	Total

	Hedges		Postretirement Items	
Accumulated other comprehensive (loss) income at Jan. 1	$(51,151)	$ 110	$ (59,313)	$(110,354)
Other comprehensive income before reclassifications	49	1	—	50
Losses reclassified from net accumulated other comprehensive loss	2,609	—	2,886	5,495
Net current period other comprehensive income	2,658	1	2,886	5,545
Accumulated other comprehensive (loss) income at Sept. 30	$(48,493)	$ 111	$ (56,427)	$(104,809)

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(Thousands of Dollars)	Nine Months Ended Sept. 30, 2016 Gains and Losses on Cash Flow Hedges	Unrealized Gains on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$(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)

Reclassifications from accumulated other comprehensive loss for the three and nine months ended Sept. 30, 2017 and 2016 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Three Months Ended Sept. 30, 2017	Three Months Ended Sept. 30, 2016
Losses (gains) on cash flow hedges:		
Interest rate derivatives	$ 1,579 (a)	$ 1,502 (a)
Vehicle fuel derivatives	(11) (b)	46 (b)
Total, pre-tax	1,568	1,548
Tax benefit	(587)	(588)
Total, net of tax	981	960
Defined benefit pension and postretirement losses:		
Amortization of net loss	1,622 (c)	1,478 (c)
Prior service credit	(58) (c)	(64) (c)
Total, pre-tax	1,564	1,414
Tax benefit	(582)	(536)
Total, net of tax	982	878
Total amounts reclassified, net of tax	$ 1,963	$ 1,838

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Nine Months Ended Sept. 30, 2017	Nine Months Ended Sept. 30, 2016
Losses (gains) on cash flow hedges:		

Interest rate derivatives	$ 4,257 [a]	$ 4,470 [a]
Vehicle fuel derivatives	(16) [b]	150 [b]
Total, pre-tax	4,241	4,620
Tax benefit	(1,632)	(1,786)
Total, net of tax	2,609	2,834
Defined benefit pension and postretirement losses:		
Amortization of net loss	4,868 [c]	4,434 [c]
Prior service credit	(177) [c]	(192) [c]
Total, pre-tax	4,691	4,242
Tax benefit	(1,805)	(1,635)
Total, net of tax	2,886	2,607
Total amounts reclassified, net of tax	$ 5,495	$ 5,441

[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 2017 and 2018 earnings per share guidance and assumptions, are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “po and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly 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, 2016, and subsequent securities filings), 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 or 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.

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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	2017	2016	2017	2016
NSP-Minnesota	$0.45	$0.41	$0.81	$0.74
PSCo	0.37	0.34	0.78	0.74
SPS	0.13	0.13	0.25	0.24
NSP-Wisconsin	0.04	0.05	0.12	0.11
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.04
Regulated utility [a]	1.00	0.94	1.98	1.87
Xcel Energy Inc. and other	(0.03)	(0.04)	(0.10)	(0.11)
GAAP diluted EPS	$0.97	$0.90	$1.88	$1.76

[a] Amounts may not add due to rounding.

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.

Summary of Earnings

Xcel Energy — Xcel Energy’s earnings increased $0.07 per share for the third quarter of 2017 and $0.12 per share year-to-date. Earnings for the third quarter of 2017 increased due to higher electric margins to recover infrastructure investments, along with a lower ETR and lower O&M expenses, partially offset by higher depreciation expense and property taxes.

NSP-Minnesota — Earnings increased $0.04 per share for the third quarter of 2017 and $0.07 per share year-to-date. The year-to-date increase in earnings reflects electric rate increases, lower ETR and reduced O&M expenses. The decrease in the ETR is largely driven by resolution of IRS appeals/audits and an increase in research and experimentation credits. The lower O&M expenses primarily relate to the timing of maintenance activities and the overhauls at various generation facilities and reduced expense for nuclear refueling outages. These positive factors were partially offset by depreciation expense (for additional capital investments, including the Courtenay Wind Farm, and prior year amortization of Minnesota’s excess depreciation reserve) and higher property taxes.

PSCo — Earnings increased $0.03 per share for the third quarter of 2017 and $0.04 per share year-to-date. The year-to-date increase in earnings, driven by higher electric margins, lower O&M expenses and lower ETR, were partially offset by increased depreciation expense associated with electric and natural gas investments. The lower O&M expenses are driven by the timing of maintenance and overhauls at various generation facilities and the impact of costs associated with storm damage in 2016.

SPS — Earnings were flat for the third quarter of 2017 and increased $0.01 per share year-to-date. The year-to-date increase in electric margin was attributable to rate increases in Texas and New Mexico, partially offset by the impact of unfavorable weather. This increase was largely offset by higher depreciation expense for transmission and distribution investments and timing of O&M expenses, including the prior year deferrals associated with the Texas 2016 rate case.

NSP-Wisconsin — Earnings decreased $0.01 per share for the third quarter of 2017 and increased $0.01 per share year-to-date. The year-to-date change was driven by increases in electric and natural gas rates, partially offset by depreciation expense primarily related to transmission and distribution investments and the impact of unfavorable weather.

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Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2017 EPS compared with the same period in 2016:

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30	Nine Months Ended Sept. 30
2016 GAAP diluted EPS	$ 0.90	$ 1.76
Components of change — 2017 vs. 2016		
Higher electric margins	0.02	0.14
Lower ETR [(a)]	0.07	0.10
Lower O&M expenses	0.06	0.07
Higher natural gas margins	—	0.01
Higher depreciation and amortization	(0.05)	(0.16)
Higher conservation and DSM expenses (offset by higher revenues)	(0.01)	(0.03)
Other, net	(0.02)	(0.01)
2017 GAAP diluted EPS	$ 0.97	$ 1.88

(a) Lower ETR includes the impact of an additional $9.6 million and $18.4 million of wind production tax credits (PTCs) for the three and nine months ended Sept. 30, 2017, respectively, which are largely flowed back to customers through electric margin.

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 historically used per degree of temperature. Weather deviations 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.

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		
	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016
HDD	(16.5)%	(52.6)%	67.5 %	(13.6)%	(12.7)%	(2.2)%
CDD	5.3	11.0	(4.5)	5.9	8.3	(1.8)
THI	(11.6)	6.5	(17.5)	(10.6)	8.6	(18.5)

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

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016
Retail electric	$(0.011)	$0.024	$(0.035)	$(0.032)	$0.020	$(0.052)
Firm natural gas	—	(0.001)	0.001	(0.020)	(0.014)	(0.006)
Total (excluding decoupling)	$(0.011)	$0.023	$(0.034)	$(0.052)	$0.006	$(0.058)
Decoupling – Minnesota	0.015	(0.008)	0.023	0.023	(0.009)	0.032
Total (adjusted for recovery from decoupling)	$0.004	$0.015	$(0.011)	$(0.029)	$(0.003)	$(0.026)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2017 compared to the same period in 2016:

	Three Months Ended Sept. 30				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	(6.8)%	(2.5)%	(7.4)%	(6.9)%	(5.3)%
Electric commercial and industrial	(2.7)	0.8	(1.0)	1.5	(0.9)
Total retail electric sales	(3.9)	(0.3)	(2.5)	(0.8)	(2.2)
Firm natural gas sales	8.5	4.7	N/A	11.4	6.2

	Three Months Ended Sept. 30				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	(1.5)%	(3.0)%	(2.0)%	(0.4)%	(2.1)%
Electric commercial and industrial	(1.9)	0.7	0.3	3.0	(0.2)
Total retail electric sales	(1.8)	(0.6)			