XCEL ENERGY INC
Form 10-Q
October 26, 2018

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, 2018
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 every Interactive Data File required to be submitted 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 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 ¨
	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	Oct. 19, 2018
Common Stock, $2.50 par value	513,848,752 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 millions, except per share data)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2018	2017	2018	2017
Operating revenues				
Electric	$2,802	$2,784	$7,419	$7,421
Natural gas	227	214	1,181	1,130
Other	19	19	57	58
Total operating revenues	3,048	3,017	8,657	8,609
Operating expenses				
Electric fuel and purchased power	1,040	1,006	2,907	2,850
Cost of natural gas sold and transported	58	64	537	543
Cost of sales — other	9	8	26	25
Operating and maintenance expenses	593	536	1,729	1,688
Conservation and demand side management expenses	77	74	216	206
Depreciation and amortization	440	371	1,199	1,102
Taxes (other than income taxes)	135	134	417	411
Total operating expenses	2,352	2,193	7,031	6,825
Operating income	696	824	1,626	1,784
Other expense (net)	(7)	(1)	(8)	(4)
Equity earnings of unconsolidated subsidiaries	9	7	25	22
Allowance for funds used during construction — equity	30	24	79	54
Interest charges and financing costs				
Interest charges — includes other financing costs of $6, $6, $18 and $18, respectively	177	168	523	498
Allowance for funds used during construction — debt	(13)	(11)	(35)	(25)
Total interest charges and financing costs	164	157	488	473
Income before income taxes	564	697	1,234	1,383
Income taxes	73	205	187	424
Net income	$491	$492	$1,047	$959
Weighted average common shares outstanding:				
Basic	510	509	510	508
Diluted	511	509	510	509
Earnings per average common share:				

Basic	$0.96	$0.97	$2.05	$1.89
Diluted	0.96	0.97	2.05	1.88
Cash dividends declared per common share	$0.38	$0.36	$1.14	$1.08

See Notes to Consolidated Financial Statements

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2018	2017	2018	2017
Net income	$491	$492	$1,047	$959
Other comprehensive income				
Pension and retiree medical benefits:				
Net pension and retiree medical losses arising during the period, net of tax of $(1), $0, $(1), and $0, respectively	(2)	—	(2)	—
Amortization of losses included in net periodic benefit cost, net of tax of $1, $1, $2 and $1, respectively	4	1	6	3
	2	1	4	3
Derivative instruments:				
Reclassification of losses to net income, net of tax of $0, $1, $1 and $2, respectively	1	1	2	2
Other comprehensive income	3	2	6	5
Comprehensive income	$494	$494	$1,053	$964

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

	Nine Months Ended Sept. 30	
	2018	2017
Operating activities		
Net income	$1,047	$959
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	1,213	1,113
Nuclear fuel amortization	92	88
Deferred income taxes	184	501
Allowance for equity funds used during construction	(79)	(54)
Equity earnings of unconsolidated subsidiaries	(25)	(22)
Dividends from unconsolidated subsidiaries	27	32
Share-based compensation expense	25	44
Other, net	(16)	(3)
Changes in operating assets and liabilities:		
Accounts receivable	(48)	(31)
Accrued unbilled revenues	114	104
Inventories	37	(9)
Other current assets	52	64
Accounts payable	37	(68)
Net regulatory assets and liabilities	164	(27)
Other current liabilities	(158)	(112)
Pension and other employee benefit obligations	(134)	(135)
Change in other noncurrent assets	12	(15)
Change in other noncurrent liabilities	(51)	(62)
Net cash provided by operating activities	2,493	2,367
Investing activities		
Utility capital/construction expenditures	(2,760)	(2,256)
Allowance for equity funds used during construction	79	54
Purchases of investment securities	(494)	(972)
Proceeds from the sale of investment securities	479	949
Other, net	(10)	(14)
Net cash used in investing activities	(2,706)	(2,239)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(376)	122
Proceeds from issuances of long-term debt	1,381	1,422
Repayments of long-term debt, including reacquisition premiums	(301)	(1,030)
Proceeds from issuance of common stock	203	—
Dividends paid	(544)	(538)
Other, net	(20)	(21)
Net cash provided by (used in) financing activities	343	(45)
Net change in cash and cash equivalents	130	83

Cash and cash equivalents at beginning of period	83	84
Cash and cash equivalents at end of period	$213	$167
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(491)	$(489)
Cash (paid) received for income taxes, net	(4)	42
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$328	$269
Issuance of common stock for equity awards	52	23

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

	Sept. 30, 2018	Dec. 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$213	$83
Accounts receivable, net	856	797
Accrued unbilled revenues	650	764
Inventories	528	610
Regulatory assets	452	424
Derivative instruments	76	44
Prepaid taxes	71	68
Prepayments and other	157	183
Total current assets	3,003	2,973
Property, plant and equipment, net	35,879	34,329
Other assets		
Nuclear decommissioning fund and other investments	2,473	2,397
Regulatory assets	3,166	3,005
Derivative instruments	42	48
Other	272	278
Total other assets	5,953	5,728
Total assets	$44,835	$43,030
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$556	$457
Short-term debt	437	814
Accounts payable	1,189	1,243
Regulatory liabilities	410	239
Taxes accrued	428	448
Accrued interest	158	174
Dividends payable	194	183
Derivative instruments	31	29
Other	435	501
Total current liabilities	3,838	4,088
Deferred credits and other liabilities		
Deferred income taxes	4,119	3,845
Deferred investment tax credits	54	58
Regulatory liabilities	5,161	5,083
Asset retirement obligations	2,572	2,475
Derivative instruments	107	126
Customer advances	200	193

Pension and employee benefit obligations	909	1,042
Other	202	145
Total deferred credits and other liabilities	13,324	12,967
Commitments and contingencies		
Capitalization		
Long-term debt	15,508	14,520
Common stock — 1,000,000,000 shares authorized of $2.50 par value; and 513,298,952 507,762,881 shares outstanding at Sept. 30, 2018 and Dec. 31, 2017, respectively	1,283	1,269
Additional paid in capital	6,125	5,898
Retained earnings	4,876	4,413
Accumulated other comprehensive loss	(119)	(125)
Total common stockholders' equity	12,165	11,455
Total liabilities and equity	$44,835	$43,030

See Notes to Consolidated Financial Statements

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

	Common Stock Issued				Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Other Comprehensive Loss	Common Stockholders' Equity
Three Months Ended Sept. 30, 2018 and 2017						
Balance at June 30, 2017	507,763	$1,269	$ 5,882	$4,079	$ (107)	$ 11,123
Net income				492		492
Other comprehensive income					2	2
Dividends declared on common stock				(184)		(184)
Share-based compensation			7	(1)		6
Balance at Sept. 30, 2017	507,763	$1,269	$ 5,889	$4,386	$ (105)	$ 11,439
Balance at June 30, 2018	508,898	$1,272	$ 5,920	$4,580	$ (122)	$ 11,650
Net income				491		491
Other comprehensive income					3	3
Dividends declared on common stock				(195)		(195)
Issuances of common stock	4,401	11	197			208
Share-based compensation			8	—		8
Balance at Sept. 30, 2018	513,299	$1,283	$ 6,125	$4,876	$ (119)	$ 12,165

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Nine Months Ended Sept. 30, 2018 and 2017						
Balance at Dec. 31, 2016	507,223	$1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				959		959
Other comprehensive income					5	5
Dividends declared on common stock				(552)		(552)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			7	(3)		4
Balance at Sept. 30, 2017	507,763	$1,269	$ 5,889	$ 4,386	$ (105)	$ 11,439
Balance at Dec. 31, 2017	507,763	$1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				1,047		1,047
Other comprehensive income					6	6
Dividends declared on common stock				(584)		(584)
Issuances of common stock	5,558	14	221			235
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			7	—		7
Balance at Sept. 30, 2018	513,299	$1,283	$ 6,125	$ 4,876	$ (119)	$ 12,165

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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, 2018 and Dec. 31, 2017; 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, 2018 and 2017; and its cash flows for the nine months ended Sept. 30, 2018 and 2017. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2018 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, 2017 balance sheet information has been derived from the audited 2017 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2017. 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, 2017, filed with the SEC on Feb. 23, 2018. 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, 2017, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Leases — In February 2016, the Financial Accounting Standards Board (FASB) issued Leases, Topic 842 (Accounting Standards Update (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. Adoption will occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard and included in Targeted Improvements, Topic 842 (ASU No. 2018-11). On Jan. 1, 2019, agreements historically disclosed as operating leases for the use of real estate, equipment and certain fossil-fueled generating facilities operated under purchased power agreements (PPAs) are expected to be recognized on the consolidated balance sheet. Other than first-time recognition of these types of operating leases on the consolidated balance sheet, the implementation is not expected to have a significant impact on Xcel Energy's consolidated financial statements.

Recently Adopted

Revenue Recognition — In May 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09), which provides a new framework for the recognition of revenue. Xcel Energy implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. Other than increased disclosures regarding revenues related to contracts with customers, the implementation did not have a material impact on Xcel Energy's consolidated financial statements. For related disclosures, see Note 14 to the consolidated financial statements.

Classification and Measurement of Financial Instruments — In January 2016, the FASB issued Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01), which eliminated the available-for-sale classification for marketable equity securities and also replaced 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 recognized in earnings. Xcel Energy implemented the guidance on Jan. 1, 2018. 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, historically classified as available-for-sale, continue to be deferred to a regulatory asset, and the overall adoption impacts were not material.

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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. As a result of the application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment, and the impacts of adoption will be limited to changes in classification of non-service costs in the consolidated statement of income. Xcel Energy implemented the new guidance on Jan. 1, 2018, and as a result, $6 million and $18 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the consolidated income statement for the three and nine months ended Sept. 30, 2017, respectively. Under a practical expedient permitted by the standard, Xcel Energy used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Selected Balance Sheet Data

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Accounts receivable, net		
Accounts receivable	$909	$ 849
Less allowance for bad debts	(53)	(52)
	$856	$ 797

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$267	$ 311
Fuel	151	186
Natural gas	110	113
	$528	$ 610

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Property, plant and equipment, net		
Electric plant	$39,530	$39,016
Natural gas plant	6,036	5,800
Common and other property	2,100	2,013
Plant to be retired [(a)]	337	11
Construction work in progress	3,029	2,087
Total property, plant and equipment	51,032	48,927
Less accumulated depreciation	(15,483)	(15,000)
Nuclear fuel	2,717	2,697
Less accumulated amortization	(2,387)	(2,295)
	$35,879	$34,329

(a) In the third quarter of 2018, the Colorado Public Utilities Commission (CPUC) approved early retirement of PSCo’s Comanche Units 1, 2 and shared Common plant in approximately 2022, 2025 and 2025, respectively. PSCo also expects Craig Unit 1 to be early retired in approximately 2025. 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. Amounts are presented net of accumulated depreciation.

4. Income Taxes

Except to the extent noted below, Note 6 to the consolidated financial statements included in Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2017 appropriately represents, in all material respects, the current status of other income tax matters, and is incorporated herein by reference.

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Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2018	2017	2018	2017
Federal statutory rate	21.0 %	35.0 %	21.0 %	35.0 %
State tax (net of federal tax effect)	5.0	4.1	5.0	4.1
Increase (decreases) in tax from:				
Wind production tax credits (PTCs) [(a)]	(2.6)	(4.8)	(4.3)	(4.5)
Regulatory differences - ARAM [(b)]	(5.6)	(0.1)	(5.6)	(0.1)
Regulatory differences - ARAM deferral [(c)]	3.8	—	4.4	—
Regulatory differences - reversal of prior quarters' ARAM deferral [(c)]	(7.0)	—	(3.3)	—
Regulatory differences - other utility plant items	(0.6)	(0.8)	(0.7)	(0.7)
Other (net)	(1.1)	(4.0)	(1.3)	(3.1)
Effective income tax rate	12.9 %	29.4 %	15.2 %	30.7 %

(a) Quarterly PTCs may vary due to production and timing differences. Annual 2018 PTCs are forecasted to exceed 2017.

(b) The average rate assumption method (ARAM); a method to flow back excess deferred taxes to customers.

(c) ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

Federal Audits — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy’s federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020

In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals (Appeals) reached an agreement and the benefit related to the agreed upon portions was recognized. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

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). Xcel Energy filed a protest with the IRS. As of Sept. 30, 2018, the case has been forwarded to Appeals and 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, 2018, 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, 2018, Minnesota had not proposed any material adjustments;
- In 2016, Wisconsin began an audit of years 2012 and 2013. The audit concluded in the third quarter of 2018 with no material adjustments; and
- As of Sept. 30, 2018, there were no other state income tax audits in progress.

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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, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 27	$ 20
Unrecognized tax benefit — Temporary tax positions	11	19
Total unrecognized tax benefit	$ 38	$ 39

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, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (36)	$ (31)

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 audit resumes, the Minnesota audit progresses, and other state audits resume. As the IRS Appeals and Minnesota audit progress and the IRS audit resumes, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $29 million.

Payables for interest related to unrecognized tax benefits were not material and no amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2018 or Dec. 31, 2017.

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, 2017 and in Note 5 to the consolidated financial statements to Xcel Energy Inc.’s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

Tax Reform — Regulatory Proceedings

The specific impacts of the TCJA on customer rates are subject to regulatory approval. The following details the status of regulatory decisions in each state where Xcel Energy operates.

NSP-Minnesota —
Minnesota — In August 2018, the Minnesota Public Utilities Commission (MPUC) ordered NSP-Minnesota to refund the 2018 impacts of TCJA, including $5 million to natural gas customers and $131 million to electric customers, including low income program funding of $2 million.

NSP-Minnesota — South Dakota — In July 2018, the South Dakota Public Utilities Commission approved a settlement providing a one-time customer refund of $11 million for the 2018 impact of the TCJA, while NSP-Minnesota would retain the benefits of the TCJA in 2019 and 2020 in exchange for a two-year rate case moratorium.

NSP-Minnesota — North Dakota — Natural Gas — In August 2018, NSP-Minnesota and the North Dakota Public Service Commission (NDPSC) Staff reached a TCJA settlement, in which NSP-Minnesota would amortize $1 million annually of the regulatory asset for the remediation of the manufactured gas plant (MGP) site in Fargo, N.D. beginning in 2018, and retain the TCJA savings to approximately offset the MGP amortization expense. The TCJA benefits would be incorporated into a future rate case and the MGP amortization would then be recoverable through the cost of gas rider until fully amortized. A NDPSC decision related to the settlement is expected to be received by the end of 2018. See Note 6 for further discussion of the Fargo, N.D. MGP Site.

NSP-Minnesota — North Dakota — Electric — In October 2018, NSP-Minnesota and the NDPSC Staff reached a settlement which included a one-time customer refund of $10 million for 2018, while NSP- Minnesota would retain the benefits of the TCJA in 2019 and 2020 in exchange for a two-year rate case moratorium. The settlement also includes an earnings sharing provision in which annual weather normalized earnings exceeding an ROE of 9.85 percent are returned to customers.

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A NDPSC decision related to the settlement is expected to be received by the end of 2018 or during the first quarter of 2019.

NSP-Wisconsin — In May 2018, the Public Service Commission of Wisconsin (PSCW) issued its final order which requires customer refunds of $27 million and defers approximately $5 million until NSP-Wisconsin's next rate case proceeding.

NSP-Wisconsin — Michigan — In May 2018, the Michigan Public Service Commission approved electric and natural gas tax reform settlement agreements. Most of the electric TCJA benefits were included in NSP-Wisconsin's recently approved Michigan 2018 electric base rate case. The return of natural gas TCJA benefits is expected to be completed in 2019.

PSCo — Colorado Natural Gas — In February 2018, the administrative law judge (ALJ) recommended approval of PSCo and the CPUC Staff's TCJA settlement agreement which included a $20 million reduction to provisional rates effective March 1, 2018. In September 2018, PSCo submitted a TCJA true-up filing and revised its TCJA benefit estimate to $24 million and requested an equity ratio of 56 percent to offset the negative impact of the TCJA on credit metrics. A decision is expected in the fourth quarter of 2018. The true-up of the estimated TCJA benefit is expected to be retroactive to January 2018.

PSCo — Colorado Electric — In April 2018, PSCo, the CPUC Staff, and the Office of Consumer Counsel (OCC) filed a TCJA settlement agreement for 2018 that included a customer refund of $42 million in 2018, with the remainder of the $59 million of TCJA benefits to be used to accelerate the amortization of an existing prepaid pension asset. In June 2018, the CPUC approved the customer refund of $42 million. In October 2018, the accelerated amortization of the prepaid pension asset was effective by operation of law. For 2019, the expected customer refund is estimated to be $67 million and amortization of the prepaid pension asset is estimated to be $34 million. Impacts of the TCJA for 2020 and beyond are expected to be addressed in a future electric rate case.

SPS — Texas — In June 2018, SPS, the Public Utility Commission of Texas (PUCT) Staff and various intervenors reached a settlement in the Texas electric rate case which included the impacts of the TCJA. The settlement reflects no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be up to a 57 percent equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings. A PUCT decision is expected in the fourth quarter of 2018.

SPS — New Mexico — In September 2018, the New Mexico Public Regulation Commission (NMPRC) issued its final order in SPS' 2017 electric rate case, which included a refund of the 2018 impact of the TCJA.

Other Regulatory Proceedings

NSP-Minnesota

Recently Concluded Regulatory Proceedings — MPUC and the NDPSC

PPA Terminations and Amendments — In June 2018, NSP-Minnesota terminated the Benson and Laurentian PPAs, and purchased the Benson biomass facility. As a result, a $103 million regulatory asset was recognized for the costs of the Benson transaction, including payments to Benson of $93 million, as well as other transaction costs and future estimated facility removal costs. For Laurentian, a regulatory asset of $109 million was recognized for annual termination payments over six years. The regulatory approvals provide for recovery of the Benson regulatory asset over approximately 10 years, and for recovery of the Laurentian termination payments as they occur, through fuel and purchased energy recovery mechanisms. The termination of the PPAs is expected to save customers over $600 million over the next 10 years.

PSCo

Pending Regulatory Proceedings — CPUC

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 was based on forward test years, a 10.0 percent ROE and an equity ratio of 55.25 percent.
In August 2018, the CPUC issued an interim decision that included application of a 2016 historic test year (HTY), with a 13-month average rate base, an ROE of 9.35 percent, an equity ratio of 54.6 percent and provided no return on the prepaid pension and retiree medical asset. With these adjustments, the total rate increase, prior to TCJA impacts, would be $47 million. PSCo filed an interim rehearing request to preserve its rights and the CPUC decided that any reconsideration can be brought after a final order incorporating TCJA impacts. The CPUC is expected to issue its order on the natural gas rate case and the final decision related to the impacts of the TCJA in the fourth quarter of 2018.

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PSIA Rider
In October 2018, PSCo, CPUC Staff, and the OCC filed a settlement agreement to extend the PSIA rider through 2021. The CPUC is expected to rule on the settlement in the fourth quarter of 2018.

SPS

Pending Regulatory Proceedings — PUCT

Texas 2017 Electric Rate Case — In 2017, SPS filed a $54 million, or 5.8 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 a HTY ended June 30, 2017, a requested ROE of 10.25 percent, an electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent.

In May 2018, SPS filed rebuttal testimony and revised its request to an overall increase in the annual base rate revenue of approximately $32 million, or 5.9 percent, net of the TCJA (after adjusting for a requested 58 percent equity ratio) and other adjustments. This request would be equivalent to approximately $17 million after adjusting for the Transmission Cost Recovery Factor (TCRF) rider.

In June 2018, SPS, the PUCT Staff and various intervenors reached a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt.

The following are key terms:

- The ability to use an equity ratio that reflects SPS' actual capital structure, up to 57 percent;
- A 9.5 percent ROE for the calculation of allowance for funds used during construction (AFUDC);
- TCRF rider will remain in effect;
- SPS will accelerate the depreciable lives of Tolk Units 1 and 2 from 2042 and 2045, respectively, to 2037; and
- SPS agrees that it will file its next base rate case no later than Dec. 31, 2019.

A PUCT decision on the settlement is expected in the fourth quarter of 2018.

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

New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $43 million. The request was based on a HTY ended June 30, 2017, a ROE of 10.25 percent, an equity ratio of 53.97 percent, a 35 percent federal income tax rate and a rate base of approximately $885 million, including rate base additions through Nov. 30, 2017.

In May 2018, SPS reduced its request to $27 million, net of the TCJA (approximately $11 million, net of the requested higher equity ratio) and other adjustments, based on a requested ROE of 10.25 percent and an equity ratio of 58.0 percent.

In June 2018, the New Mexico Hearing Examiner issued a recommended decision proposing an increase of $12 million, based on a ROE of 9.4 percent and an equity ratio of 53.97 percent. She also denied SPS' requests to shorten depreciation lives related to Tolk Units 1 and 2 and Cunningham Unit 1. The Hearing Examiner rejected intervenor proposals to refund the impacts of the TCJA back to Jan. 1, 2018.

On Sept. 5, 2018, the NMPRC issued its final order resulting in a revenue increase of approximately $8 million, or 2.1 percent, effective Sept. 27, 2018, based on a ROE of 9.1 percent and a 51 percent equity ratio. The NMPRC also ordered a refund of $10 million associated with the TCJA impacts for the retroactive period of Jan. 1, 2018 through Sept. 27, 2018. SPS recorded a regulatory liability of $10 million for the customer refund in the third quarter of 2018. On Sept. 7, 2018, SPS filed an appeal with the NMSC on the grounds that the NMPRC's findings are contrary to the factual record and do not result in just and reasonable rates as required by law. In addition, SPS filed a motion for stay with the NMSC to delay the implementation of the retroactive TCJA refund until the NMSC issues its decision on SPS' appeal of the rate case order. SPS considers the refund illegal primarily because it violates the prohibition on retroactive ratemaking and results in rates that are not just and reasonable. On Sept. 26, 2018, the NMSC granted a temporary stay to delay the implementation of the retroactive refund until further order of the Court.

Appeal of the New Mexico 2016 Electric Rate Case Dismissal — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $41 million, representing a total revenue increase of approximately 10.9 percent.

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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 ended June 30, 2018. In 2017, the NMPRC dismissed SPS' rate case. SPS filed a notice of appeal in the NMSC. A decision is not expected until the second half of 2019.

Pending Regulatory Proceeding — Federal Energy Regulatory Commission (FERC)

Midcontinent Independent System Operator, Inc. (MISO) Return on Equity (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 September 2016, the FERC approved an ALJ recommendation that MISO TOs be granted a 10.32 percent base ROE using the methodology adopted by FERC in June 2014 (Opinion 531). 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. 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 RTO adder was filed, resulting in a second period of potential refunds from Feb. 12, 2015 to May 11, 2016. In June 2016, an ALJ recommended a base ROE of 9.7 percent, applying the FERC Opinion 531 methodology. FERC action is pending. In April 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) 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.

NSP-Minnesota has recognized a current refund liability consistent with the best estimate of the final ROE.

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 2016, the FERC granted SPP's request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately $13 million for these charges. SPP is also billing SPS ongoing charges of approximately $0.5 million per month. In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these charges was remanded to the FERC. As of September 2018, SPS' recovery of these charges (from 2008 through 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC denied SPS' complaint. SPS sought rehearing in April 2018, and the FERC granted a rehearing for purposes of further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5 of the consolidated financial statements, 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, 2017 and in Notes 5 and 6 to Xcel Energy Inc.'s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, 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.

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.

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The Xcel Energy utility subsidiaries had approximately 3,540 Megawatts (MW) of capacity under long-term PPAs as of Sept. 30, 2018 and 3,537 MW as of Dec. 31, 2017, 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 various 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. Xcel Energy Inc.'s exposure is based upon the net liability 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, 2018 and Dec. 31, 2017, 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, 2018	Dec. 31, 2017
Guarantees issued and outstanding	$18.1	$ 18.8
Current exposure under these guarantees	—	—
Bonds with indemnity protection	51.1	53.1

Other Indemnification Agreements

Xcel Energy Inc. and its subsidiaries provide indemnifications through various contracts. 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 responsible party 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, an adjacent city lakeshore park area, and a sediment area of Lake Superior's Chequamegon Bay. NSP-Wisconsin completed wet dredging at the Site in August of 2018 and anticipates completion of final site restoration activities in early 2019. Groundwater treatment activities at the Site will continue for many years.

The current cost estimate for the remediation of the entire site is approximately $184 million, of which approximately $156 million has been spent. As of Sept. 30, 2018 and Dec. 31, 2017, NSP-Wisconsin recorded a total liability of $28 million and $30 million, respectively, for the entire site.

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 December 2017, the PSCW approved an NSP-Wisconsin natural gas rate case, which included recovery of additional expenses associated with remediating the Site. The annual recovery of MGP clean-up costs increased from $12 million in 2017 to $18 million in 2018.

Fargo, N.D. MGP Site — NSP-Minnesota is remediating a former MGP site in Fargo, N.D. Remediation is expected to be completed by early November 2018, and several years of groundwater monitoring is expected to follow. NSP-Minnesota has also initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota has set a trial date for Spring of 2020.

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NSP-Minnesota recorded an estimated liability of $6 million as of Sept. 30, 2018 and $16 million as of Dec. 31, 2017, for the Fargo MGP Site. The current cost estimate for the remediation of the site is approximately $25 million, of which approximately $19 million has been spent. NSP-Minnesota has deferred Fargo MGP Site costs allocable to the North Dakota jurisdiction, or approximately 88 percent of all remediation costs, as approved by the NDPSC. In October 2018, the MPUC denied NSP-Minnesota's request to defer post-2017 MGP remediation expenditures allocable to the Minnesota jurisdiction, including the Fargo MGP Site.

Other MGP, Landfill or Disposal Sites — Xcel Energy is currently involved in investigating and/or remediating several MGP, landfill or other disposal sites. Xcel Energy has identified eleven sites across its service territories in addition to the Ashland MGP Site and the Fargo MGP Site, where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities. Xcel Energy anticipates that these investigation or remediation activities will continue through at least 2019. Xcel Energy accrued $4 million as of Sept. 30, 2018 and Dec. 31, 2017 for all of these sites. There may be insurance recovery and/or recovery from other responsible parties that will offset any costs incurred.

Environmental Requirements

Water and Waste

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the United States Environmental Protection Agency published a final rule regulating the management, storage, and disposal of coal combustion residuals (CCRs) as a nonhazardous waste (CCR Rule).

Under the CCR Rule, utilities are required to complete certain groundwater sampling around their CCR landfills and surface impoundments. Xcel Energy has identified at least one site in Colorado where there are impoundments and/or landfills present and where a statistically significant increase of certain constituents exist in the groundwater. However, at that location, Xcel Energy has completed removal of CCR from the impoundments. Xcel Energy is currently conducting additional groundwater sampling and will evaluate whether corrective action is required at any CCR landfills or surface impoundments. Until Xcel Energy completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial position or cash flows. Xcel Energy believes that any associated costs would be recoverable through regulatory mechanisms.

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 seeking monetary damages 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.

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e prime, Xcel Energy Inc. 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 a 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.” In March 2017, summary judgment was granted by the MDL judge in favor of Xcel Energy and e prime in the Sinclair Oil and Farmland cases. In November 2017, the U.S. District Court in Nevada granted summary judgment against two plaintiffs in the Arandell Corp. case in favor of Xcel Energy and NSP-Wisconsin, leaving only three individual plaintiffs remaining in the litigation. In addition, the plaintiffs’ motions for class certification and remand back to originating courts in these cases were denied in March 2017. Plaintiffs appealed the summary judgment motions granted in the Farmland and Sinclair Oil cases and the denial of class certification and remand to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). In March 2018, the Ninth Circuit reversed and remanded the summary judgment in the Farmland case. The Farmland defendants subsequently filed a request for further review by the Ninth Circuit, which was denied. Upon Sinclair’s request, the Ninth Circuit reversed and remanded the summary judgment in the Sinclair case. Plaintiffs have asked the lower court to remand the cases back to the court where the actions were originally filed. The defendants have moved for the lower court to issue a renewed summary judgment in the Farmland case. Later in the summer of 2018 the Ninth Circuit also vacated, but did not reverse, the lower court’s denial of class certification. The defendants have drafted a proposal for a renewed denial for the lower court’s consideration. 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 the Denver District 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 involved claims by over fifty developers. In February 2018, the Colorado Supreme Court denied DRC’s petition to appeal the Denver District Court’s dismissal of the lawsuit, effectively terminating this litigation. However, in January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so. This claim is substantially similar to the arguments previously raised by DRC. PSCo filed a motion to dismiss this claim, which was granted in May 2018. DRC subsequently filed an appeal to the Colorado Court of Appeals. It is uncertain when a decision will be rendered regarding this appeal.

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.

Short-Term Debt — 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 and term loan agreements.

Commercial paper and term loan borrowings outstanding for Xcel Energy were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$3,000	$3,250
Amount outstanding at period end	437	814
Average amount outstanding	634	644
Maximum amount outstanding	824	1,247
Weighted average interest rate, computed on a daily basis	2.45 %	1.35 %
Weighted average interest rate at period end	2.57	1.90

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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, 2018 and Dec. 31, 2017, there were $49 million and $30 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, 2018, 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.	$ 1,250	$ 378	$ 872
PSCo	700	10	690
NSP-Minnesota	500	61	439
SPS	400	37	363
NSP-Wisconsin	150	—	150
Total	$ 3,000	$ 486	$ 2,514

(a) These credit facilities expire in June 2021, with the exception of Xcel Energy Inc.'s 364-day term loan agreement entered into in December 2017.

(b) Includes outstanding commercial paper, term loan borrowings and letters of credit.

In addition, Xcel Energy Inc. entered into a $500 million 364-day term loan in December 2017. As of Sept. 30, 2018, $250 million of borrowings remain outstanding with no additional borrowing capacity.

All credit facility bank borrowings, outstanding letters of credit, term loan borrowings 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, 2018 and Dec. 31, 2017.

Long-Term Borrowings

During the nine months ended Sept. 30, 2018, Xcel Energy Inc. and its utility subsidiaries issued the following:

- PSCo issued $350 million of 3.70 percent first mortgage green bonds due June 15, 2028 and $350 million of 4.10 percent first mortgage green bonds due June 15, 2048;
- Xcel Energy Inc. issued $500 million of 4.00 percent senior notes due June 15, 2028; and
- NSP-Wisconsin issued $200 million of 4.20 percent first mortgage bonds due Sept. 1, 2048.

At-The-Market Equity Offering

In September 2018, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $300 million of its common stock through an at-the-market offering (ATM) program in addition to $75 million of equity to be issued through the dividend reinvestment program and benefit programs. As of Sept. 30, 2018, Xcel Energy Inc. had settled 4.2 million shares of common stock with net proceeds of $199.3 million, through the ATM program. In addition, transaction fees of $1.7 million were paid. In October 2018, an additional 0.5 million shares were settled with net proceeds of $25.5 million and transaction fees of $0.2 million.

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8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

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

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

Specific valuation methods include the following:

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

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.

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If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited 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 Prairie Island (PI) nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the asset class target allocations approved by the MPUC for the 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 impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were $600 million and $560 million as of Sept. 30, 2018 and Dec. 31, 2017, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $22 million and $7 million as of Sept. 30, 2018 and Dec. 31, 2017, respectively.

The following tables present the cost and fair value of Xcel Energy’s non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund as of Sept. 30, 2018 and Dec. 31, 2017:

	Sept. 30, 2018					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV [b]	Total
Nuclear decommissioning fund [a]						
Cash equivalents	$33	$33	$—	$ —	$ —	$33
Commingled funds:						
Non U.S. equities	262	196	—	—	91	287
Emerging market debt funds	163	—	—	—	165	165
Private equity investments	170	—	—	—	250	250
Real estate	125	—	—	—	198	198
Debt securities:						
Government securities	76	—	73	—	—	73
U.S. corporate bonds	334	—	330	—	—	330
Non U.S. corporate bonds	56	—	55	—	—	55

Equity securities:						
U.S. equities	258	591	—	—	—	591
Non U.S. equities	156	229	—	—	—	229
Total	$1,633	$1,049	$458	$ —	$ 704	$2,211

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $140 million of equity investments in unconsolidated subsidiaries and $122 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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	Dec. 31, 2017					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV [(b)]	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$29	$29	$—	$ —	$ —	$29
Commingled funds:						
Non U.S. equities	264	217	—	—	90	307
Emerging market debt funds	156	—	—	—	166	166
Private equity investments	141	—	—	—	198	198
Real estate	131	—	—	—	202	202
Other commingled funds	9	6	—	—	3	9
Debt securities:						
Government securities	68	—	69	—	—	69
U.S. corporate bonds	320	—	322	—	—	322
Non U.S. corporate bonds	50	—	50	—	—	50
Equity securities:						
U.S. equities	271	557	—	—	—	557
Non U.S. equities	152	234	—	—	—	234
Total	$1,591	$1,043	$441	$ —	$ 659	$2,143

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $140 million of equity investments in unconsolidated subsidiaries and $114 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.

For the three and nine months ended Sept. 30, 2018 and 2017 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, 2018:

	Final Contractual Maturity				
(Millions 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	$—	$—	$2	$71	$73
U.S. corporate bonds	13	91	176	50	330
Non U.S. corporate bonds	2	20	28	5	55
Debt securities	$15	$111	$206	$126	$458

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Rabbi Trusts

In 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, 2018 and Dec. 31, 2017:

	Sept. 30, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$20	$20	$ —	$ —	$ 20
Mutual funds	46	51	—	—	51
Total	$66	$71	$ —	$ —	$ 71

	Dec. 31, 2017				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$12	$12	$ —	$ —	$ 12
Mutual funds	47	50	—	—	50
Total	$59	$62	$ —	$ —	$ 62

(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.

As of Sept. 30, 2018, accumulated other comprehensive losses related to interest rate derivatives included $3 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, 2018, 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, 2018 and 2017.

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As of Sept. 30, 2018, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included immaterial 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, 2018 and Dec. 31, 2017:

(Amounts in Millions) [a][b]	Sept. 30, 2018	Dec. 31, 2017
Megawatt hours of electricity	92	68
Million British thermal units of natural gas	42	37

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

The following tables detail the impact of derivative activity during the three and nine months ended Sept. 30, 2018 and 2017 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2018				
	Pre-Tax Fair Value (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Millions 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 (a)	$ —	$ —
Total	$ —	$ —	$ 1	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 5 (b)
Electric commodity	—	(2)	—	— (c)	—
Natural gas commodity	—	(2)	—	— (d)	— (d)
Total	$ —	$ (4)	$ —	$ —	$ 5

	Nine Months Ended Sept. 30, 2018				
	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
(Millions of Dollars)				Regulatory	

	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 3 [(a)]	$ —	$ —
Total	$ —	$ —	$ 3	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 14 [(b)]
Electric commodity	—	6	—	— [(c)]	—
Natural gas commodity	—	(1)	—	2 [(d)]	(2) [(d)]
Total	$ —	$ 5	$ —	$ 2	$ 12

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	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
(Millions 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	$ —	$ —	$ 2 [(a)]	$ —	$ —
Total	$ —	$ —	$ 2	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 1 [(b)]
Electric commodity	—	18	—	(3) [(c)]	—
Natural gas commodity	—	(2)	—	— [(d)]	— [(d)]
Total	$ —	$ 16	$ —	$ (3)	$ 1

	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
(Millions 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 [(a)]	$ —	$ —
Total	$ —	$ —	$ 4	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 8 [(b)]
Electric commodity	—	17	—	(9) [(c)]	—
Natural gas commodity	—	(10)	—	1 [(d)]	(4) [(d)]
Total	$ —	$ 7	$ —	$ (8)	$ 4

(a) Amounts are recorded to interest charges.

(b) 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.

(c) 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.

(d) 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, 2018 included no settlement gains or losses and $1 million of settlement losses, respectively. Amounts for the three and nine months ended Sept. 30, 2017 included no settlement gains or losses and $1 million of settlement gains, respectively. The remaining derivative settlement gains and losses for the three and nine months ended Sept. 30, 2018 and 2017 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, 2018 and 2017. 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.

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

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. As of Sept. 30, 2018, five of Xcel Energy's 10 most significant counterparties for these activities, comprising $69 million or 37 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Five of the 10 most significant counterparties, comprising $30 million or 16 percent of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. All ten of these significant counterparties are 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, 2018 and Dec. 31, 2017, 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, 2018 and Dec. 31, 2017.

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, 2018:

	Sept. 30, 2018					
	Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$1	$ 39	$ 2	$ 42	$ (15)	$ 27
Electric commodity	—	—	44	44	(1)	43
Natural gas commodity	—	2	—	2	—	2
Total current derivative assets	$1	$ 41	$ 46	$ 88	$ (16)	72
PPAs [a]						4
Current derivative instruments						$ 76
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$ 32	$ 5	$ 37	$ (12)	$ 25
Total noncurrent derivative assets	$—	$ 32	$ 5	$ 37	$ (12)	25
PPAs [a]						17
Noncurrent derivative instruments						$ 42

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(Millions of Dollars)	Sept. 30, 2018 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$1	$ 35	$ 2	$ 38	$ (28)	$10
Electric commodity	—	—	1	1	(1)	—
Total current derivative liabilities	$1	$ 35	$ 3	$ 39	$ (29)	10
PPAs [a]						21
Current derivative instruments						$31
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$ 23	$ —	$ 23	$ (13)	$10
Total noncurrent derivative liabilities	$—	$ 23	$ —	$ 23	$ (13)	10
PPAs [a]						97
Noncurrent derivative instruments						$107

(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 is being 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, 2018. At Sept. 30, 2018, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $14 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, 2017:

(Millions of Dollars)	Dec. 31, 2017 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$2	$				