Section 1: 10-Q (10-Q)

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

(Mark One)

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

For the quarterly period ended June 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. ☒ Yes ☐ No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☒	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 ☒ No
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 23, 2018

Common Stock, $2.50 par value	509,087,107 shares

TABLE OF CONTENTS

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

PART I — FINANCIAL INFORMATION

Item 1 — FINANCIAL STATEMENTS

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

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Operating revenues				
Electric	$ 2,348	$ 2,338	$ 4,617	$ 4,637
Natural gas	292	290	954	915
Other	18	17	38	39
Total operating revenues	2,658	2,645	5,609	5,591
Operating expenses				
Electric fuel and purchased power	935	919	1,867	1,844
Cost of natural gas sold and transported	104	114	479	479
Cost of sales — other	8	8	17	17
Operating and maintenance expenses	578	572	1,135	1,152
Conservation and demand side management expenses	69	65	139	132
Depreciation and amortization	377	366	760	731
Taxes (other than income taxes)	137	135	282	277
Total operating expenses	2,208	2,179	4,679	4,632
Operating income	450	466	930	959
Other expense, net	(2)	(4)	(1)	(4)
Equity earnings of unconsolidated subsidiaries	9	7	16	15
Allowance for funds used during construction — equity	26	16	49	31
Interest charges and financing costs				
Interest charges — includes other financing costs of $6, $6, $12 and $12, respectively	175	164	346	330
Allowance for funds used during construction — debt	(11)	(8)	(22)	(15)
Total interest charges and financing costs	164	156	324	315
Income before income taxes	319	329	670	686
Income taxes	54	102	114	219
Net income	$ 265	$ 227	$ 556	$ 467
Weighted average common shares outstanding:				
Basic	510	509	509	508
Diluted	510	509	510	509
Earnings per average common share:				
Basic	$ 0.52	$ 0.45	$ 1.09	$ 0.92
Diluted	0.52	0.45	1.09	0.92
Cash dividends declared per common share	$ 0.38	$ 0.36	$ 0.76	$ 0.72

See Notes to Consolidated Financial Statements

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

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Net income	$ 265	$ 227	$ 556	$ 467
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $1, $1, $1 and $1, respectively	1	1	2	2
Derivative instruments:				
Reclassification of losses to net income, net of tax of $0, $1, $0 and $1, respectively	1	1	1	1
Other comprehensive income	2	2	3	3
Comprehensive income	$ 267	$ 229	$ 559	$ 470

See Notes to Consolidated Financial Statements

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

	Six Months Ended June 30	
	2018	2017
Operating activities		
Net income	$ 556	$ 467
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	769	739
Nuclear fuel amortization	62	57
Deferred income taxes	110	309
Allowance for equity funds used during construction	(49)	(31)
Equity earnings of unconsolidated subsidiaries	(16)	(15)
Dividends from unconsolidated subsidiaries	18	24
Share-based compensation expense	10	32
Other, net	(6)	(4)
Changes in operating assets and liabilities:		
Accounts receivable	(11)	17
Accrued unbilled revenues	115	121
Inventories	101	65
Other current assets	39	(84)
Accounts payable	(1)	(52)
Net regulatory assets and liabilities	143	1
Other current liabilities	(247)	(190)
Pension and other employee benefit obligations	(142)	(140)
Change in other noncurrent assets	10	(7)
Change in other noncurrent liabilities	(24)	(17)
Net cash provided by operating activities	1,437	1,292
Investing activities		
Utility capital/construction expenditures	(1,903)	(1,474)
Allowance for equity funds used during construction	49	31
Purchases of investment securities	(367)	(368)
Proceeds from the sale of investment securities	357	350
Other, net	(1)	(13)
Net cash used in investing activities	(1,865)	(1,474)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(132)	392
Proceeds from issuances of long-term debt	1,186	394
Repayments of long-term debt, including reacquisition premiums	(1)	(250)
Dividends paid	(359)	(355)
Other, net	(17)	(22)
Net cash provided by financing activities	677	159
Net change in cash and cash equivalents	249	(23)
Cash and cash equivalents at beginning of period	83	84
Cash and cash equivalents at end of period	$ 332	$ 61
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (313)	$ (301)
Cash paid for income taxes, net	(3)	(4)

Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$ 262	$ 233
Issuance of common stock for equity awards	35	19

See Notes to Consolidated Financial Statements

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

	June 30, 2018	Dec. 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 332	$ 83
Accounts receivable, net	808	797
Accrued unbilled revenues	648	764
Inventories	511	610
Regulatory assets	440	424
Derivative instruments	75	44
Prepaid taxes	78	68
Prepayments and other	164	183
Total current assets	3,056	2,973
Property, plant and equipment, net	35,289	34,329
Other assets		
Nuclear decommissioning fund and other investments	2,398	2,397
Regulatory assets	3,177	3,005
Derivative instruments	47	48
Other	273	278
Total other assets	5,895	5,728
Total assets	$ 44,240	$ 43,030
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 856	$ 457
Short-term debt	682	814
Accounts payable	1,092	1,243
Regulatory liabilities	395	239
Taxes accrued	316	448
Accrued interest	176	174
Dividends payable	193	183
Derivative instruments	27	29
Other	441	501
Total current liabilities	4,178	4,088
Deferred credits and other liabilities		
Deferred income taxes	3,973	3,845
Deferred investment tax credits	56	58
Regulatory liabilities	5,113	5,083
Asset retirement obligations	2,534	2,475
Derivative instruments	113	126
Customer advances	202	193
Pension and employee benefit obligations	884	1,042
Other	226	145
Total deferred credits and other liabilities	13,101	12,967
Commitments and contingencies		
Capitalization		

Long-term debt	15,311	14,520
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 508,898,420 and 507,762,881 shares outstanding at June 30, 2018 and Dec. 31, 2017, respectively	1,272	1,269
Additional paid in capital	5,920	5,898
Retained earnings	4,580	4,413
Accumulated other comprehensive loss	(122)	(125)
Total common stockholders' equity	11,650	11,455
Total liabilities and equity	$ 44,240	$ 43,030

See Notes to Consolidated Financial Statements

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
Three Months Ended June 30, 2018 and 2017						
Balance at March 31, 2017	507,763	$ 1,269	$ 5,873	$ 4,036	$ (109)	$ 11,069
Net income				227		227
Other comprehensive income					2	2
Dividends declared on common stock				(184)		(184)
Share-based compensation			9	—		9
Balance at June 30, 2017	507,763	$ 1,269	$ 5,882	$ 4,079	$ (107)	$ 11,123
Balance at March 31, 2018	508,662	$ 1,272	$ 5,903	$ 4,510	$ (124)	$ 11,561
Net income				265		265
Other comprehensive income					2	2
Dividends declared on common stock				(195)		(195)
Issuances of common stock	236	—	10			10
Share-based compensation			7	—		7
Balance at June 30, 2018	508,898	$ 1,272	$ 5,920	$ 4,580	$ (122)	$ 11,650

See Notes to Consolidated Financial Statements

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
Six Months Ended June 30, 2018 and 2017						
Balance at Dec. 31, 2016	507,223	$ 1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				467		467
Other comprehensive income					3	3
Dividends declared on common stock				(368)		(368)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			—	(2)		(2)
Balance at June 30, 2017	507,763	$ 1,269	$ 5,882	$ 4,079	$ (107)	$ 11,123
Balance at Dec. 31, 2017	507,763	$ 1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				556		556
Other comprehensive income					3	3
Dividends declared on common stock				(389)		(389)
Issuances of common stock	1,157	3	24			27
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			(1)	—		(1)
Balance at June 30, 2018	508,898	1,272	5,920	4,580	(122)	11,650

See Notes to Consolidated Financial Statements

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

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of June 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 six months ended June 30, 2018 and 2017; and its cash flows for the six months ended June 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 June 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. 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 and proposed in *Targeted Improvements, Topic 842* (*Proposed ASU 2018-200*). On Jan. 1, 2019 agreements considered leases for the use of office space, equipment and natural gas storage assets, as well as certain purchased power agreements (PPAs) for fossil-fueled generating facilities are expected to be recognized on the consolidated balance sheet.

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 significant 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.

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, $12 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the consolidated income statement for the six months ended June 30, 2017. 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)	June 30, 2018	Dec. 31, 2017
Accounts receivable, net		
Accounts receivable	$ 856	$ 849
Less allowance for bad debts	(48)	(52)
	$ 808	$ 797

(Millions of Dollars)	June 30, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$ 312	$ 311
Fuel	147	186
Natural gas	52	113
	$ 511	$ 610

(Millions of Dollars)	June 30, 2018	Dec. 31, 2017
Property, plant and equipment, net		
Electric plant	$ 39,745	$ 39,016
Natural gas plant	5,955	5,800
Common and other property	2,045	2,013
Plant to be retired [(a)]	10	11
Construction work in progress	2,658	2,087
Total property, plant and equipment	50,413	48,927
Less accumulated depreciation	(15,479)	(15,000)
Nuclear fuel	2,712	2,697
Less accumulated amortization	(2,357)	(2,295)
	$ 35,289	$ 34,329

(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.

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.

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 June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Federal statutory rate	21.0 %	35.0 %	21.0 %	35.0 %
State tax, net of federal tax effect	5.1	4.1	5.0	4.1
Increase (decreases) in tax from:				
Wind production tax credits (PTCs)	(5.4)	(4.5)	(5.8)	(4.2)
Regulatory differences - ARAM [a]	(5.4)	(0.1)	(5.6)	(0.1)
Regulatory differences - ARAM deferral [b]	4.0	—	4.8	—
Regulatory differences - other utility plant items	(1.0)	(0.9)	(1.0)	(0.7)
Other, net	(1.4)	(2.6)	(1.4)	(2.2)
Effective income tax rate	16.9 %	31.0 %	17.0 %	31.9 %

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

(b) The ARAM deferral may decrease during the year, which would result in a reduction to tax expense with a corresponding reduction to revenue, as we receive further direction from our regulatory commissions regarding the return of excess deferred taxes to our customers resulting from the Tax Cuts and Jobs Act (TCJA).

***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 - 2011	December 2018
2012 - 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. The IRS proposed an adjustment to the federal tax loss carryback claims and in 2015, the IRS forwarded the issue to the Office of Appeals (Appeals). In 2017, Xcel Energy and 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). After evaluating the proposed adjustment, Xcel Energy filed a protest with the IRS. As of June 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 June 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 June 30, 2018, Minnesota had not proposed any material adjustments;
- In 2016, Wisconsin began an audit of years 2012 and 2013. As of June 30, 2018, the Company is evaluating the state's proposed audit adjustments. No material accruals are expected; and
- As of June 30, 2018, 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)	June 30, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 21	$ 20
Unrecognized tax benefit — Temporary tax positions	13	19
Total unrecognized tax benefit	$ 34	$ 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)	June 30, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (33)	$ (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 and Wisconsin audits progress, and other state audits resume. As the IRS Appeals and Minnesota and Wisconsin audits progress and the IRS audit resumes, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $29 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at June 30, 2018 and Dec. 31, 2017 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of June 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 Report on Form 10-Q for the quarterly period ended March 31, 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. Each of the states in Xcel Energy's service areas have opened dockets to address the impacts of the TCJA.

NSP-Minnesota — In April 2018, NSP-Minnesota updated the estimated impact of the TCJA, which reflected an overall reduction in 2018 revenue requirements of approximately $136 million for electric and $7 million for natural gas, and made recommendations regarding the sharing of those benefits with ratepayers. The proposed electric options included: customer refunds and rider impacts of $68 million, deferral of $44 million to allow for a rate case stay-out for 2020, acceleration of depreciation for the King coal plant of $22 million and low income program funding of $2 million. The proposed natural gas options included customer refunds and rider impacts of $3 million, with the remaining TCJA benefits deferred to mitigate increased costs in the next natural gas rate case.

In June 2018, the Minnesota Department of Commerce (DOC) recommended to implement refunds for the current tax impacts (approximately $90 million), and incorporate the deferred tax impacts (approximately $53 million) in NSP-Minnesota's next electric and gas rate cases. A decision from the Minnesota Public Utilities Commission (MPUC) is expected in 2018.

NSP-Minnesota — North and South Dakota — In February 2018, NSP-Minnesota proposed using the reduced revenue requirements from the TCJA to defer planned future rate filings in North Dakota and South Dakota. In July 2018, the South Dakota Public Utilities Commission (SDPUC) approved a settlement which proposed a one-time customer refund of $11 million for the 2018 impact of the TCJA and a two-year rate case moratorium.

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 (MPSC) 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. Natural gas TCJA benefits are to be returned to customers commencing in July 2018.

PSCo — Colorado Natural Gas — In February 2018, the administrative law judge (ALJ) approved PSCo and the Colorado Public Utilities Commission (CPUC) Staff's TCJA settlement agreement, which includes a $20 million reduction to provisional rates effective March 1, 2018. A final true-up would provide customers the full net benefit of the TCJA 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 that recommended a customer refund of $42 million in 2018, with the remainder of $59 million be used to accelerate the amortization of an existing prepaid pension asset. In June 2018, the CPUC approved the customer refund of $42 million, effective June 1, 2018. The CPUC set the decision regarding the remainder of the $59 million for hearing before an ALJ. Revisions to the TCJA settlement will 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 a 57 percent equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings.

SPS — New Mexico — In February 2018, SPS indicated that the TCJA would reduce revenue requirements by approximately $11 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending New Mexico electric rate case.

Other Regulatory Proceedings

NSP-Minnesota

Recently Concluded Regulatory Proceedings — MPUC and the North Dakota Public Service Commission (NDPSC)

PPA Terminations and Amendments — In June 2018, NSP-Minnesota executed the terminations of 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.

PSCo

Pending Regulatory Proceedings — 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 was based on forecast test years (FTY), a 10.0 percent return on equity (ROE) and an equity ratio of 55.25 percent. Interim rates, subject to refund and interest, were to be effective on June 1, 2018.

Revenue Request (Millions of Dollars)	2018	2019	2020	2021	Total
Revenue request	$ 74	$ 75	$ 60	$ 36	$ 245
Clean Air Clean Jobs Act (CACJA) rider conversion to base rates	90	—	—	—	90
Transmission Cost Adjustment (TCA) rider conversion to base rates	43	—	—	—	43
Total	$ 207	$ 75	$ 60	$ 36	$ 378
Expected year-end rate base (billions of dollars)	$ 6.8	$ 7.1	$ 7.3	$ 7.4	

In March 2018, PSCo, CPUC Staff and OCC reached a settlement and filed a motion with the CPUC requesting changes to the procedural schedule and scope of the electric case, which included delaying the implementation of provisional rates from June 2018 to January 2019 and requiring PSCo to file updated test year information for 2019 through 2021 which included the impacts of TCJA. In April 2018, the CPUC denied the motion on procedural grounds and dismissed the electric rate case.

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, was 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	$ 33	$ 43	$ 139
Pipeline System Integrity Adjustment (PSIA) rider conversion to base rates (a)	—	94	—	94
Total	$ 63	$ 127	$ 43	$ 233
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 revenue as these costs are already being recovered through the rider. 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 February 2018, the ALJ approved a TCJA settlement agreement between PSCo and the CPUC Staff, which reduced provisional rates by $20 million, based on a preliminary TCJA estimate of $29 million. The settlement remains subject to CPUC approval. The impact of the TCJA will be trued-up later in 2018. Annualized provisional rates of approximately $43 million were effective March 1, 2018.

In May 2018, the ALJ issued an interim recommended decision which would result in a 2018 overall rate increase of approximately $46 million, prior to the impact of the TCJA. The estimated rate increase reflects a 2016 HTY with a 13-month average rate base of $1.6 billion, a ROE of 9.35 percent and an equity ratio of 54.2 percent.

On July 12, 2018, the CPUC deliberated and approved several of the ALJ’s recommendations including application of a 2016 HTY, with a 13-month average rate base, and an ROE of 9.35 percent. The CPUC adjusted the equity ratio to 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.

The estimated impact of the CPUC’s decision is presented below:

(Millions of Dollars)	Estimated Impact of the CPUC’s Decision
Filed 2018 revenue request based on a FTY	$ 63
Impact of the change in test year	5
PSCo’s deficiency based on a 2016 HTY - year-end rate base	68
Adjustments:	
ROE at 9.35 percent	(9)
Equity ratio of 54.6 percent	(2)
Change in amortization period for certain regulatory assets, including a debt return	(6)
Loss of return on prepaid pension and retiree medical	(4)
Change from 2016 year-end to average rate base	(5)
Other, net	5
Total adjustments	(21)
Total rate increase, prior to the TCJA impacts	$ 47

The CPUC is expected to issue its order on the natural gas rate case in the third quarter of 2018. The CPUC is expected to issue a final decision with the impacts of the TCJA later in 2018.

Provisional rates, subject to refund, were implemented on Jan. 1, 2018. A current liability which represents PSCo’s best estimate of a refund obligation associated with provisional rates was recorded as of June 30, 2018.

PSIA Rider

In June 2018, PSCo filed for an extension to the PSIA rider through 2020. PSCo requested an expedited decision by Nov. 15, 2018. PSCo also requested authorization to roll-in recovery of costs in the current PSIA rider into base rates effective Jan. 1, 2019, if the CPUC rejects the proposed PSIA extension or fails to rule on the request by the end of 2018.

Additionally, PSCo reduced PSIA revenues by approximately $8 million for 2018 for the impact of the TCJA, effective May 1, 2018. PSIA revenues are subject to the CPUC approved PSIA rider true-up process.

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. The request also reflects the acceleration of depreciation lives for the two generating units at the Tolk Generating Station from 2042 and 2045 to 2032.

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 (approximately $32 million after adjusting for a 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, which SPS has informed the parties it intends to be 57 percent to mitigate the impact of TCJA on credit metrics;
- 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 depreciation rates for the Tolk Generating Station Units 1 and 2 by 50 percent of the original request; and
- SPS agrees that it will file its next base rate case no later than Dec. 31, 2019.

A reconciliation of the settlement is as follows:

(Millions of Dollars)		
Original base rate request	$	69
Base rate revenue to be recovered through TCRF		(15)
Net revenue request		54
Adjustment for TCJA and other items		(37)
Requested incremental revenue		17
Unspecified settlement adjustments		(13)
Accelerated depreciation (Tolk plant)		(4)
SPS' net revenue change	$	—

Under the terms of the settlement, the final rates would not change from the current rates. However, SPS would be permitted to surcharge customers for unrecovered TCRF charges that were not billed during the period of Jan. 23, 2018 through June 10, 2018. A PUCT decision is expected in the third quarter of 2018.

Appeal of the Texas 2015 Electric Rate Case Decision — In 2014, SPS had requested an overall retail electric revenue rate increase of $42 million. In 2015, the PUCT approved an overall rate decrease of approximately $4 million, net of rate case expenses. In April 2016, SPS filed an appeal with the Texas State District Court (District Court) challenging the PUCT’s order. In 2017, the District Court denied SPS’ appeal, and SPS appealed the District Court’s decision to the state Court of Appeals for the 7th Circuit. In 2018, the Court of Appeals upheld the District Court’s decision on the PUCT’s order, rejecting SPS’ appeal. As part of the settlement of the 2017 Texas rate case, SPS has agreed to end its appeal.

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) 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.

The following table summarizes certain parties' proposed modifications to SPS' request, SPS' revised request, and the Hearing Examiner's recommendation:

(Millions of Dollars)	NMPRC Staff Testimony	NMAG Testimony	SPS Rebuttal Testimony	Hearing Examiner's Recommendation
SPS request	$ 43	$ 43	$ 43	$ 43
Reduction to request for the impact of the TCJA	(11)	(11)	(11)	(11)
SPS request, including the impact of the TCJA	32	32	32	32
ROE	(4)	(6)	—	(5)
Capital structure	(7)	(3)	—	(3)
Depreciation lives (Tolk and Cunningham plants)	(3)	(3)	—	(3)
Disallow rate case expenses	(2)	(3)	(1)	—
Regional transmission revenue and expense (adjustment for the impact of the TCJA):				
Impact of the TCJA	—	(3)	—	(1)
Aligning costs with transmission plant in rate base	—	—	—	(1)
Post test year plant (updated to actual)	(1)	(2)	(3)	—
Excess generation adjustment	—	(1)	—	(1)
Other, net	(4)	(4)	(1)	(6)
Recommended rate increase	$ 11	$ 7	$ 27	$ 12
ROE	9.0%	9.21%	10.25%	9.4%
Equity ratio	52.0%	53.97%	58.0%	53.97%

SPS anticipates a decision and implementation of final rates in the third quarter of 2018.

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. 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 2017, the NMPRC dismissed SPS' rate case. SPS filed a notice of appeal in the New Mexico Supreme Court. 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 November 2017, the FERC denied an SPS request for rehearing. In January 2018, SPS appealed the FERC request to the D.C. Circuit Court of Appeals. SPS has filed to recover the SPP charges as part of the appeal. The appeal is currently pending.

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 approved the rehearing request for further consideration on May 7, 2018. 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 Report on Form 10-Q for the quarterly period ended March 31, 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.

The Xcel Energy utility subsidiaries had approximately 3,470 Megawatts (MW) of capacity under long-term PPAs as of June 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 June 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)	June 30, 2018	Dec. 31, 2017
Guarantees issued and outstanding	$ 18.4	$ 18.8
Current exposure under these guarantees	—	—
Bonds with indemnity protection	$ 51.8	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 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), an adjacent city lakeshore park area (Kreher Park) (collectively the Phase I Area); and a sediment area of Lake Superior's Chequamegon Bay (Phase II Area). NSP-Wisconsin initiated a wet dredge remedy of the Phase II area in 2017. NSP-Wisconsin anticipates completion of Phase II activities in 2018 with 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 $175 million, of which approximately $146 million has been spent. As of June 30, 2018 and Dec. 31, 2017, NSP-Wisconsin recorded a total liability of $29 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 — 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 and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). The North Dakota Department of Health approved NSP-Minnesota's proposed cleanup plan in January 2017, which involves targeted source removal of impacted soils and historic MGP infrastructure. Remediation activities commenced in June 2018. 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.

NSP-Minnesota recorded an estimated liability of $10 million as of June 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 $22 million, of which approximately $12 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 December 2017, NSP-Minnesota filed a request with the MPUC to defer post-2017 MGP remediation expenditures allocable to the Minnesota jurisdiction, including the Fargo MGP Site. In March 2018, the DOC recommended that the MPUC deny NSP-Minnesota's deferral request. A MPUC decision is expected in the third quarter of 2018.

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 contamination is present and 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 2018. Xcel Energy accrued $5 million as of June 30, 2018 and $4 million as of Dec. 31, 2017 for all of these sites. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. Xcel Energy anticipates that any amounts spent will be fully recovered from customers.

Environmental Requirements

Air

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. Xcel Energy meets the 2015 ozone standard in all areas where its generating units operate, except for the Denver Metropolitan Area. PSCo's retirement of its coal fired plants in the Denver non-attainment area helped Colorado's plan to mitigate non-attainment. In June 2018, the EPA designated the parts of the Denver Metropolitan Area that currently do not attain the 2008 ozone standards as also not attaining the more stringent 2015 ozone standard. Colorado will continue to consider further reductions that are available in the non-attainment area as it develops plans to meet the ozone standards. The gas plants that operate in PSCo's non-attainment area may be required to improve or add controls, implement further work practices and/or implement enhanced emissions monitoring as part of future Colorado state plans.

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 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. Taking into account the decision in the Farmland case, the Sinclair plaintiffs have requested the Ninth Circuit to reverse the grant of summary judgment without hearing. Oral arguments were presented to the Ninth Circuit in July 2018 regarding this issue and the denial of class certification and it is uncertain when a decision will be issued. 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 June 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 3,000	$ 3,250
Amount outstanding at period end	682	814
Average amount outstanding	1,028	644
Maximum amount outstanding	1,349	1,247
Weighted average interest rate, computed on a daily basis	2.42%	1.35%
Weighted average interest rate at period end	2.47	1.90

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At June 30, 2018 and Dec. 31, 2017, there were $42 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 June 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	$ 520	$ 730
PSCo	700	4	696
NSP-Minnesota	500	36	464
SPS	400	134	266
NSP-Wisconsin	150	30	120
Total	$ 3,000	$ 724	$ 2,276

(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 June 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 June 30, 2018 and Dec. 31, 2017.

Long-Term Borrowings

During the three months ended June 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; and
- Xcel Energy Inc. issued $500 million of 4.00 percent senior notes due June 15, 2028.

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.

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 $547 million and $560 million as of June 30, 2018 and Dec. 31, 2017, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $23 million and $7 million as of June 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 June 30, 2018 and Dec. 31, 2017:

	June 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	$ 31	$ 31	$ —	$ —	$ —	$ 31
Commingled funds:						
Non U.S. equities	262	199	—	—	90	289
Emerging market debt funds	158	—	—	—	158	158
Private equity investments	151	—	—	—	220	220
Real estate	128	—	—	—	197	197
Debt securities:						
Government securities	76	—	75	—	—	75
U.S. corporate bonds	330	—	323	—	—	323
Non U.S. corporate bonds	58	—	56	—	—	56
Equity securities:						
U.S. equities	269	568	—	—	—	568
Non U.S. equities	157	227	—	—	—	227
Total	$ 1,620	$ 1,025	$ 454	$ —	$ 665	$ 2,144

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $138 million of equity investments in unconsolidated subsidiaries and $115 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, 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 six months ended June 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 June 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	$ —	$ 4	$ 2	$ 69	$ 75
U.S. corporate bonds	5	90	172	56	323
Non U.S. corporate bonds	2	20	30	4	56
Debt securities	$ 7	$ 114	$ 204	$ 129	$ 454

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 June 30, 2018 and Dec. 31, 2017:

	June 30, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 11	$ 11	$ —	$ —	$ 11
Mutual funds	37	51	—	—	51
Total	$ 48	$ 62	$ —	$ —	$ 62

	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 June 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 June 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 six months ended June 30, 2018 and 2017.

As of June 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 June 30, 2018 and Dec. 31, 2017:

(Amounts in Millions) [a][b]	June 30, 2018	Dec. 31, 2017
Megawatt hours of electricity	108	68
Million British thermal units of natural gas	26	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 six months ended June 30, 2018 and 2017 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended June 30, 2018				
	Pre-Tax Fair Value Gains Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1 [a]	$ —	$ —
Total	$ —	$ —	$ 1	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 2 [b]
Electric commodity	—	37	—	(3) [c]	—
Total	$ —	$ 37	$ —	$ (3)	$ 2

	Six Months Ended June 30, 2018				
	Pre-Tax Fair Value Gains Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1 (a)	$ —	$ —
Total	$ —	$ —	$ 1	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 10 (b)
Electric commodity	—	8	—	—	—
Natural gas commodity	—	—	—	2 (d)	(2) (d)
Total	$ —	$ 8	$ —	$ 2	$ 8

	Three Months Ended June 30, 2017				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 2 (a)	$ —	$ —
Total	$ —	$ —	$ 2	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 6 (b)
Electric commodity	—	(1)	—	(2) (c)	—
Natural gas commodity	—	(2)	—	—	—
Total	$ —	$ (3)	$ —	$ (2)	$ 6

	Six Months Ended June 30, 2017				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 2 (a)	$ —	$ —
Total	$ —	$ —	$ 2	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 7 (b)
Electric commodity	—	—	—	(6) (c)	—
Natural gas commodity	—	(8)	—	1 (d)	(4) (d)
Total	$ —	$ (8)	$ —	$ (5)	$ 3

(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 six months ended June 30, 2018 included no settlement gains or losses and $1 million of settlement losses, respectively. Amounts for the three and six months ended June 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 six months ended June 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 six months ended June 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.

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 June 30, 2018, four of Xcel Energy's 10 most significant counterparties for these activities, comprising $56 million or 29 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 $40 million or 21 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 $5 million or 3 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 June 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 June 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 June 30, 2018:

	June 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	$ 27	$ 2	$ 30	$ (18)	$ 12
Electric commodity	—	—	59	59	(1)	58
Natural gas commodity	—	1	—	1	—	1
Total current derivative assets	$ 1	$ 28	$ 61	$ 90	$ (19)	71
PPAs [(a)]						4
Current derivative instruments						$ 75
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 35	$ 6	$ 41	$ (12)	$ 29
Total noncurrent derivative assets	$ —	$ 35	$ 6	$ 41	$ (12)	29
PPAs [(a)]						18
Noncurrent derivative instruments						$ 47

(Millions of Dollars)	June 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	$ 24	$ 2	$ 27	$ (22)	$ 5
Electric commodity	—	—	1	1	(1)	—
Total current derivative liabilities	$ 1	$ 24	$ 3	$ 28	$ (23)	5
PPAs [(a)]						22
Current derivative instruments						$ 27
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$ —	$ 27	$ —	$ 27	$ (15)	$ 12
Total noncurrent derivative liabilities	$ —	$ 27	$ —	$ 27	$ (15)	12
PPAs [(a)]						101
Noncurrent derivative instruments						$ 113

(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 June 30, 2018. At June 30, 2018, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $8 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, Xcel Energy’s derivative assets and liabilities measured at fair value on a recurring basis 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	$ 22	$ —	$ 24	$ (15)	$ 9
Electric commodity	—	—	32	32	(2)	30
Total current derivative assets	$ 2	$ 22	$ 32	$ 56	$ (17)	39
PPAs [(a)]						5
Current derivative instruments						$ 44
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$ —	$ 31	$ 5	$ 36	$ (7)	$ 29
Total noncurrent derivative assets	$ —	$ 31	$ 5	$ 36	$ (7)	29
PPAs [(a)]						19
Noncurrent derivative instruments						$ 48

(Millions of Dollars)	Dec. 31, 2017 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$ 2	$ 18	$ —	$ 20	$ (15)	$ 5
Electric commodity	—	—	2	2	(2)	—
Natural gas commodity	—	1	—	1	—	1
Total current derivative liabilities	$ 2	$ 19	$ 2	$ 23	$ (17)	6
PPAs [a]						23
Current derivative instruments						$ 29
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$ —	$ 24	$ —	$ 24	$ (10)	$ 14
Total noncurrent derivative liabilities	$ —	$ 24	$ —	$ 24	$ (10)	14
PPAs [a]						112
Noncurrent derivative instruments						$ 126

(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 Dec. 31, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $3 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the three and six months ended June 30, 2018 and 2017:

(Millions of Dollars)	Three Months Ended June 30 2018	2017
Balance at April 1	$ 19	$ 6
Purchases	45	76
Settlements	(20)	(22)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings [a]	(2)	6
Net gains recognized as regulatory assets and liabilities	22	3
Balance at June 30	$ 64	$ 69

(Thousands of Dollars)	Six Months Ended June 30 2018	2017
Balance at Jan. 1	$ 35	$ 17
Purchases	46	80
Settlements	(32)	(42)
Net transactions recorded during the period:		
Gains recognized in earnings [a]	—	5
Net gains recognized as regulatory assets and liabilities	15	9
Balance at June 30	$ 64	$ 69

(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 six months ended June 30, 2018 and 2017.

Fair Value of Long-Term Debt

As of June 30, 2018 and Dec. 31, 2017, other financial instruments for which the carrying amount did not equal fair value were as follows:

	June 30, 2018		Dec. 31, 2017	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 16,167	$ 16,750	$ 14,977	$ 16,531

The fair value of Xcel Energy’s long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of June 30, 2018 and Dec. 31, 2017, 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 Expense, Net

Other expense, net consisted of the following:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	**2018**	**2017**	**2018**	**2017**
Interest income	$ 3	$ 2	$ 7	$ 6
Other nonoperating income	1	2	2	5
Insurance policy expense	(2)	(1)	(1)	(2)
Benefits non-service costs	(4)	(7)	(9)	(13)
Other expense, net	$ (2)	$ (4)	$ (1)	$ (4)

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 $138 million and $140 million as of June 30, 2018 and Dec. 31, 2017, respectively, included in the regulated natural gas utility segment.

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

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

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2018					
Operating revenues from external customers	$ 2,348	$ 292	$ 18	$ —	$ 2,658
Intersegment revenues	—	—	—	—	—
Total revenues	$ 2,348	$ 292	$ 18	$ —	$ 2,658
Net income (loss)	$ 264	$ 27	$ (26)	$ —	$ 265

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2017					
Operating revenues from external customers	$ 2,338	$ 290	$ 17	$ —	$ 2,645
Intersegment revenues	1	—	—	(1)	—
Total revenues	$ 2,339	$ 290	$ 17	$ (1)	$ 2,645
Net income (loss)	$ 227	$ 13	$ (13)	$ —	$ 227

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2018					
Operating revenues from external customers	$ 4,617	$ 954	$ 38	$ —	$ 5,609
Intersegment revenues	1	1	—	(2)	—
Total revenues	$ 4,618	$ 955	$ 38	$ (2)	$ 5,609
Net income (loss)	$ 483	$ 121	$ (48)	$ —	$ 556

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2017					
Operating revenues from external customers	$ 4,637	$ 915	$ 39	$ —	$ 5,591
Intersegment revenues	1	1	—	(2)	—
Total revenues	$ 4,638	$ 916	$ 39	$ (2)	$ 5,591
Net income (loss)	$ 422	$ 76	$ (31)	$ —	$ 467

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.

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

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

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

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017		
(Amounts in millions, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$ 265	—	—	$ 227	—	—
Basic EPS:						
Earnings available to common shareholders	265	509.6	$ 0.52	227	508.5	$ 0.45
Effect of dilutive securities:						
Equity awards	—	0.4	—	—	0.6	—
Diluted EPS:						
Earnings available to common shareholders	$ 265	510.0	$ 0.52	$ 227	509.1	$ 0.45

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
(Amounts in millions, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$ 556	—	—	$ 467	—	—
Basic EPS:						
Earnings available to common shareholders	556	509.3	$ 1.09	467	508.4	$ 0.92
Effect of dilutive securities:						
Equity awards	—	0.4	—	—	0.6	—
Diluted EPS:						
Earnings available to common shareholders	$ 556	509.7	$ 1.09	$ 467	509.0	$ 0.92

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2018	2017	2018	2017
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 24	$ 24	$ 1	$ 1
Interest cost [a]	33	36	5	6
Expected return on plan assets [a]	(52)	(52)	(6)	(6)
Amortization of prior service credit [a]	(1)	—	(3)	(3)
Amortization of net loss [a]	27	26	2	1
Net periodic benefit cost (credit)	31	34	(1)	(1)
Costs not recognized due to the effects of regulation	(1)	(4)	—	—
Net benefit cost (credit) recognized for financial reporting	$ 30	$ 30	$ (1)	$ (1)

(Millions of Dollars)	Six Months Ended June 30 Pension Benefits 2018	Pension Benefits 2017	Postretirement Health Care Benefits 2018	Postretirement Health Care Benefits 2017
Service cost	$ 47	$ 48	$ 1	$ 2
Interest cost [(a)]	67	72	11	12
Expected return on plan assets [(a)]	(104)	(104)	(13)	(12)
Amortization of prior service credit [(a)]	(2)	(1)	(5)	(5)
Amortization of net loss [(a)]	55	53	3	2
Net periodic benefit cost (credit)	63	68	(3)	(1)
Costs not recognized due to the effects of regulation	(2)	(8)	—	—
Net benefit cost (credit) recognized for financial reporting	$ 61	$ 60	$ (3)	$ (1)

(a) The components of net periodic cost other than the service cost component are included in the line item “other expense, net” in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2018, contributions of $150 million were made across four of Xcel Energy’s pension plans. Xcel Energy does not expect additional pension contributions during 2018.

13. Other Comprehensive Loss

Changes in accumulated other comprehensive loss, net of tax, for the three and six months ended June 30, 2018 and 2017 were as follows:

(Millions of Dollars)	Three Months Ended June 30, 2018 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at April 1	$ (58)	$ (66)	$ (124)
Losses reclassified from net accumulated other comprehensive loss	1	1	2
Net current period other comprehensive income	1	1	2
Accumulated other comprehensive loss at June 30	$ (57)	$ (65)	$ (122)

(Millions of Dollars)	Three Months Ended June 30, 2017 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at April 1	$ (51)	$ (58)	$ (109)
Losses reclassified from net accumulated other comprehensive loss	1	1	2
Net current period other comprehensive income	1	1	2
Accumulated other comprehensive loss at June 30	$ (50)	$ (57)	$ (107)

(Millions of Dollars)	Six Months Ended June 30, 2018 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (58)	$ (67)	$ (125)
Losses reclassified from net accumulated other comprehensive loss	1	2	3
Net current period other comprehensive income	1	2	3
Accumulated other comprehensive loss at June 30	$ (57)	$ (65)	$ (122)

(Millions of Dollars)	Six Months Ended June 30, 2017 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (51)	$ (59)	$ (110)
Losses reclassified from net accumulated other comprehensive loss	1	2	3
Net current period other comprehensive income	1	2	3
Accumulated other comprehensive loss at June 30	$ (50)	$ (57)	$ (107)

Reclassifications from accumulated other comprehensive loss for the three and six months ended June 30, 2018 and 2017 were as follows:

(Millions of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended June 30, 2018	Three Months Ended June 30, 2017
Losses on cash flow hedges:		
Interest rate derivatives	$ 1 (a)	$ 2 (a)
Total, pre-tax	1	2
Tax benefit	—	(1)
Total, net of tax	1	1
Defined benefit pension and postretirement losses:		
Amortization of net loss	2 (b)	2 (b)
Total, pre-tax	2	2
Tax benefit	(1)	(1)
Total, net of tax	1	1
Total amounts reclassified, net of tax	$ 2	$ 2

(Millions of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Losses on cash flow hedges:		
Interest rate derivatives	$ 1 (a)	$ 2 (a)
Total, pre-tax	1	2
Tax benefit	—	(1)
Total, net of tax	1	1
Defined benefit pension and postretirement losses:		
Amortization of net loss	3 (b)	3 (b)
Total, pre-tax	3	3
Tax benefit	(1)	(1)
Total, net of tax	2	2
Total amounts reclassified, net of tax	$ 3	$ 3

(a) Included in interest charges

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 12 to the consolidated financial statements for details regarding these benefit plans.

14. Revenues

Xcel Energy principally generates revenue from the generation, transmission, distribution and sale of electricity and the transportation, distribution and sale of natural gas to wholesale and retail customers. Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. Xcel Energy recognizes revenue in an amount that corresponds directly to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized. Contract terms are generally short-term in nature, and as such Xcel Energy does not recognize a separate financing component of its collections from customers. Xcel Energy presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO, and SPS participates in SPP. Xcel Energy's utility subsidiaries recognize sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

Xcel Energy Inc.'s utility subsidiaries have various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred. When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify as alternative revenue programs under GAAP. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met (including collection within 24 months), revenue is recognized equal to the revenue requirement, which may include return on rate base items and incentives. The mechanisms are revised periodically for differences between the total amount collected and the revenue recognized, which may increase or decrease the level of revenue collected from customers. Alternative revenue is recorded on a gross basis and is disclosed separate from revenue from contracts with customers in the period earned.

In the following tables, revenue is classified by the type of goods/services rendered and market/customer type. The tables also reconcile revenue to the reportable segments.

	Three Months Ended June 30, 2018			
(Millions of Dollars)	**Electric**	**Natural Gas**	**All Other**	**Total**
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 678	$ 157	$ 9	$ 844
Commercial and industrial (C&I)	1,206	82	5	1,293
Other	33	—	2	35
Total retail	1,917	239	16	2,172
Wholesale	194	—	—	194
Transmission	132	—	—	132
Other	24	23	—	47
Total revenue from contracts with customers	2,267	262	16	2,545
Alternative revenue and other	81	30	2	113
Total revenues	$ 2,348	$ 292	$ 18	$ 2,658

(Millions of Dollars)	Three Months Ended June 30, 2017 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 654	$ 163	$ 9	$ 826
C&I	1,243	85	4	1,332
Other	33	—	1	34
Total retail	1,930	248	14	2,192
Wholesale	172	—	—	172
Transmission	126	—	—	126
Other	27	23	—	50
Total revenue from contracts with customers	2,255	271	14	2,540
Alternative revenue and other	83	19	3	105
Total revenues	$ 2,338	$ 290	$ 17	$ 2,645

(Millions of Dollars)	Six Months Ended June 30, 2018 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,365	$ 547	$ 18	$ 1,930
C&I	2,318	289	12	2,619
Other	66	—	4	70
Total retail	3,749	836	34	4,619
Wholesale	382	—	—	382
Transmission	255	—	—	255
Other	63	51	—	114
Total revenue from contracts with customers	4,449	887	34	5,370
Alternative revenue and other	168	67	4	239
Total revenues	$ 4,617	$ 954	$ 38	$ 5,609

(Millions of Dollars)	Six Months Ended June 30, 2017 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,339	$ 537	$ 17	$ 1,893
C&I	2,391	280	13	2,684
Other	65	—	3	68
Total retail	3,795	817	33	4,645
Wholesale	353	—	—	353
Transmission	247	—	—	247
Other	52	47	—	99
Total revenue from contracts with customers	4,447	864	33	5,344
Alternative revenue and other	190	51	6	247
Total revenues	$ 4,637	$ 915	$ 39	$ 5,591

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 2018 earnings per share guidance, the TCJA’s impact to Xcel Energy and its customers, long-term earnings per share and dividend growth rate, as well as assumptions and other statements are intended to be identified in this document by the words “anticipate,” “believe,” “could,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should,” “will,” “would” 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, 2017, 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; 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.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from the most directly comparable measure calculated and presented in accordance with GAAP. Xcel Energy’s management uses non-GAAP measures 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. Non-GAAP financial measures are intended to supplement investors’ understanding of our operating performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies’ similarly titled non-GAAP financial measures.

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses and natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas sold and transported are generally recovered through various regulatory recovery mechanisms, and as a result, changes in these expenses are generally offset in operating revenues. Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales - other, O&M expenses, conservation and demand side management (DSM) expenses, depreciation and amortization and taxes (other than income taxes).

Earnings Adjusted for Certain Items (Ongoing Earnings and Diluted EPS)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. 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 these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the three and six months ended June 30, 2017 and 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

Results of Operations

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.

The following table summarizes GAAP and ongoing diluted EPS for Xcel Energy:

	Three Months Ended June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	**2018**	**2017**	**2018**	**2017**
PSCo	$ 0.24	$ 0.20	$ 0.50	$ 0.42
NSP-Minnesota	0.18	0.17	0.40	0.36
SPS	0.11	0.07	0.18	0.12
NSP-Wisconsin	0.03	0.03	0.09	0.07
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility [(a)]	0.58	0.48	1.19	0.99
Xcel Energy Inc. and other	(0.06)	(0.03)	(0.10)	(0.07)
Total	**$ 0.52**	**$ 0.45**	**$ 1.09**	**0.92**

[(a)] Amounts may not add due to rounding.

Summary of Earnings

Explanations for operating company results below exclude the offsetting impacts on sales and income tax expense of the TCJA.

Xcel Energy — Xcel Energy's earnings increased $0.07 per share for the second quarter of 2018 and increased $0.17 per share year-to-date. Increased electric and natural gas margins (excluding the impact of the TCJA), which reflect favorable weather compared to last year and sales growth, and increased AFUDC, partially offset by higher operating and maintenance (O&M) expenses, as well as depreciation and interest expenses.

PSCo — Earnings increased $0.04 per share for the second quarter of 2018 and increased $0.08 per share year-to-date. The year-to-date increase in earnings was driven by higher electric and natural gas margins due to the impact of an interim rate increase, subject to refund, and favorable weather and increased AFUDC primarily related to the Rush Creek wind project. These items were partially offset by higher interest charges and depreciation expense.

NSP-Minnesota — Earnings increased $0.01 per share for the second quarter of 2018 and increased $0.04 per share year-to-date. The year-to-date increase reflects lower O&M expenses and higher electric and natural gas margins due to favorable weather. These positive factors were partially offset by higher depreciation expense due to increased invested capital.

SPS — Earnings increased by $0.04 per share for the second quarter of 2018 and increased $0.06 per share year-to-date. The year-to-date increase was largely due to timing of O&M expenses, the favorable impact of weather, sales growth and lower interest expense.

NSP-Wisconsin — Earnings were flat for the second quarter of 2018 and increased $0.02 per share year-to-date. The year-to-date increase was driven by higher natural gas and electric rates and the impact of favorable weather, partially offset by additional depreciation expense related to higher invested capital.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items.
The decrease in earnings was primarily related to the tax impact related to the TCJA as well as higher short-term debt levels.

Changes in GAAP and Ongoing Diluted EPS

The following table summarizes significant components contributing to the changes in 2018 EPS compared with the same period in 2017:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
GAAP and ongoing diluted EPS — 2017	**$ 0.45**	**$ 0.92**
Components of change — 2018 vs. 2017		
Higher electric margins (excluding TCJA impacts) [a]	0.07	0.11
Higher natural gas margins (excluding TCJA impacts) [a]	0.03	0.07
Higher AFUDC — equity	0.02	0.04
(Higher) lower O&M expenses	(0.01)	0.02
(Higher) lower ETR (excluding TCJA impacts) [a] [b]	(0.01)	0.01
Higher depreciation and amortization	(0.01)	(0.03)
Higher interest charges	(0.01)	(0.02)
Higher taxes (other than income taxes)	—	(0.01)
Higher conservation and demand side management (DSM) expenses [c]	—	(0.01)
Other, net	(0.01)	(0.01)
GAAP and ongoing diluted EPS — 2018	**$ 0.52**	**$ 1.09**

[a] Estimated net impact of the TCJA, which includes assumptions regarding future outcome of pending regulatory proceedings:

	Three Months Ended June 30	Six Months Ended June 30
Income tax — rate change and ARAM (net of deferral)	$ 0.11	$ 0.21
Electric revenue reductions	(0.08)	(0.16)
Natural gas revenue reductions	(0.01)	(0.02)
Holding company — interest expense	(0.02)	(0.03)
Total	$ —	$ —

[b] The ETR includes the impact of an additional $10 million and $15 million of wind PTCs for the three and six months ended June 30, 2018, which are largely flowed back to customers through electric margin.

[c] Offset by higher revenues.

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 June 30			Six Months Ended June 30		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
HDD	0.1%	(9.8)%	9.4%	0.3%	(8.5)%	14.8%
CDD	59.1	5.4	53.1	59.7	7.4	50.7
THI	108.1	(3.9)	125.3	107.4	(6.9)	125.1

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

	Three Months Ended June 30			Six Months Ended June 30		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
Retail electric	$ 0.065	$ 0.005	$ 0.060	$ 0.067	$ (0.021)	$ 0.088
Firm natural gas	0.002	(0.002)	0.004	0.003	(0.020)	0.023
Total (before adjustments for decoupling)	$ 0.067	$ 0.003	$ 0.064	$ 0.070	$ (0.041)	$ 0.111
Decoupling – Minnesota	(0.030)	—	(0.030)	(0.032)	0.009	(0.041)
Total (adjusted for decoupling)	$ 0.037	$ 0.003	$ 0.034	$ 0.038	$ (0.032)	$ 0.070

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2018 compared to the same period in 2017:

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	3.9 %	11.9%	12.2%	9.1%	8.7%
Electric commercial and industrial	0.5	3.2	5.2	2.8	2.8
Total retail electric sales	1.6	5.5	6.4	4.3	4.4
Firm natural gas sales	(3.2)	27.5	N/A	27.6	7.2

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	0.6 %	0.5%	1.5%	(0.8)%	0.6%
Electric commercial and industrial	(0.2)	0.8	4.1	1.3	1.3
Total retail electric sales	—	0.7	3.6	0.8	1.1
Firm natural gas sales	3.3	2.2	N/A	7.6	3.2

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	2.7%	7.5%	10.0%	7.0%	6.0%
Electric commercial and industrial	1.1	1.8	5.2	3.8	2.6
Total retail electric sales	1.6	3.5	6.1	4.7	3.5
Firm natural gas sales	8.4	19.3	N/A	19.2	12.6

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	0.1%	(0.5)%	1.3%	(1.1)%	(0.1)%
Electric commercial and industrial	0.7	0.1	4.5	2.8	1.5
Total retail electric sales	0.5	(0.1)	4.0	1.7	1.1
Firm natural gas sales	2.3	1.2	N/A	3.3	2.0

(a) Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized and actual growth (decline) estimates.

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

- PSCo’s higher residential sales reflect customer additions partially offset by lower use per customer. Commercial and industrial (C&I) growth was mainly due to an increase in customers and higher use for large C&I customers that support the fabricated metal, food products and metal mining industries.
  - NSP-Minnesota’s residential sales decrease was a result of lower use per customer, partially offset by customer growth. The increase in C&I sales was a result of an increase in customers partially offset by lower use per customer. Increased sales to large customers in manufacturing and energy offset declines in services, largely related to energy efficiency.
  - SPS’ residential sales grew largely due to higher use per customer and customer additions. The increase in C&I sales was driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin’s residential sales decline was primarily attributable to lower use per customer partially offset by customer additions. C&I growth was largely due to higher use per large customer, customer additions and increased sales to small and large sand mining customers and large customers in the energy industries.

Weather-normalized Natural Gas Sales Growth — Year-To-Date

- Across most service territories, higher natural gas sales reflect an increase in the number of customers combined with increasing customer use.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. The following table details the electric revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2018	2017	2018	2017
Electric revenues before impact of the TCJA	$ 2,422	$ 2,338	$ 4,755	$ 4,637
Electric fuel and purchased power before impact of the TCJA	(939)	(919)	(1,873)	(1,844)
Electric margin before impact of the TCJA	$ 1,483	$ 1,419	$ 2,882	$ 2,793
Impact of the TCJA (offset as a reduction in income tax expense)	(70)	—	(132)	—
Electric margin	$ 1,413	$ 1,419	$ 2,750	2,793

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

Electric Revenues

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Fuel and purchased power cost recovery	$ (11)	$ (24)
Trading	26	47
Estimated impact of weather (net of Minnesota decoupling)	24	39
Wholesale transmission revenue	17	29
Retail sales growth (including Minnesota decoupling and sales true-up)	10	14
Retail rate increase (Wisconsin, Texas and Michigan)	5	12
Non-fuel riders	7	8
Other, net	6	(7)
Total increase in electric revenues before impact of the TCJA	$ 84	$ 118
Impact of the TCJA (offset as a reduction in income tax expense)	(74)	(138)
Total increase (decrease) in electric revenues	$ 10	$ (20)

Electric Margin

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Estimated impact of weather (net of Minnesota decoupling)	24	39
Purchased capacity costs	12	23
Retail sales growth (including Minnesota decoupling and sales true-up)	10	14
Retail rate increase (Wisconsin, Texas and Michigan)	5	12
Non-fuel riders	7	8
Other, net	6	(7)
Total increase in electric margin before impact of the TCJA	$ 64	$ 89
Impact of the TCJA (offset as a reduction in income tax expense)	(70)	(132)
Total decrease in electric margin	$ (6)	$ (43)

Natural Gas Revenues and Margin

Total natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to natural gas cost recovery mechanisms. The following table details natural gas revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2018	2017	2018	2017
Natural gas revenues before impact of the TCJA	$ 301	$ 290	$ 974	$ 915
Cost of natural gas sold and transported	(104)	(114)	(479)	(479)
Natural gas margin before impact of the TCJA	$ 197	$ 176	$ 495	$ 436
Impact of the TCJA (offset as a reduction in income tax expense)	(9)	—	(20)	—
Natural gas margin	$ 188	$ 176	$ 475	$ 436

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Retail rate increase (Colorado - interim, subject to refund, Wisconsin and Michigan)	$ 12	$ 24
Estimated impact of weather	3	18
Infrastructure and integrity riders	5	9
Sales growth	1	3
Purchased natural gas adjustment clause recovery	(9)	(1)
Other, net	(1)	6
Total increase in natural gas revenues before impact of the TCJA	$ 11	$ 59
Impact of the TCJA (offset as a reduction in income tax expense)	(9)	(20)
Total increase in natural gas revenues	$ 2	$ 39

Natural Gas Margin

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Retail rate increase (Colorado - interim, subject to refund, Wisconsin and Michigan)	$ 12	$ 24
Estimated impact of weather	3	18
Infrastructure and integrity riders	5	9
Sales growth	1	3
Other, net	—	5
Total increase in natural gas margin before impact of the TCJA	$ 21	$ 59
Impact of the TCJA (offset as a reduction in income tax expense)	(9)	(20)
Total increase in natural gas margin	$ 12	$ 39

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $6 million, or 1.0 percent, for the second quarter of 2018 and decreased $17 million, or 1.5 percent, year-to-date. The year-to-date change largely reflects expense timing. The significant changes are summarized in the table below:

(Millions of Dollars)	Three Months Ended June 30, 2018 vs. 2017	Six Months Ended June 30, 2018 vs. 2017
Nuclear plant operations and amortization	$ (6)	$ (16)
Plant generation costs	8	—
Other, net	4	(1)
Total increase (decrease) in O&M expenses	$ 6	$ (17)

- Nuclear plant operations and amortization expenses are lower largely reflecting expense timing, savings initiatives and reduced refueling outage costs.
- Plant generation costs increased in the second quarter primarily due to the timing of planned maintenance and overhauls at a number of generation facilities.

Conservation and DSM Expenses — Conservation and DSM expenses increased $4 million, or 6.2 percent, for the second quarter of 2018 and increased $7 million, or 5.3 percent, year-to-date. The year-to-date increase was primarily due to higher recovery rates in Colorado. Increased participation in Minnesota natural gas conservation programs was partially offset by lower recovery rates. Conservation and DSM expenses are generally recovered in our major jurisdictions concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

Depreciation and Amortization — Depreciation and amortization increased $11 million, or 3.0 percent, for the second quarter of 2018 and increased $29 million, or 4.0 percent, year-to-date. The increase was primarily driven by capital expenditures due to planned system investments and amortization of certain regulatory assets, partially offset by lower depreciation rates in Minnesota.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $2 million, or 1.5 percent, for the second quarter of 2018 and increased $5 million, or 1.8 percent, year-to-date. The increase was primarily due to higher property taxes in Colorado.

AFUDC, Equity and Debt — AFUDC increased $13 million for the second quarter of 2018 and $25 million year-to-date. The increase was primarily due to the Rush Creek wind project in Colorado and other capital investments.

Interest Charges — Interest charges increased $11 million, or 6.7 percent, for the second quarter of 2018 and increased $16 million, or 4.8 percent, year-to-date. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $48 million for the second quarter of 2018 compared with the same period in 2017. The decrease and corresponding lower ETR was primarily driven by a lower federal tax rate due to the TCJA, an increase in plant-related regulatory differences related to ARAM (net of deferrals) and an increase in wind production tax credits. The ETR was 16.9 percent for the second quarter of 2018 compared with 31.0 percent for the same period in 2017.

Income tax expense decreased $105 million for the first six months of 2018 compared with the same period in 2017. The decrease and corresponding lower ETR was primarily driven by a lower federal tax rate due to the TCJA, an increase in plant-related regulatory differences related to ARAM (net of deferrals), and an increase in wind production tax credits. The ETR was 17.0 percent for the first six months of 2018 compared with 31.9 percent for the same period in 2017. See Note 4 to the consolidated financial statements.

Public Utility Regulation

Except to the extent noted below and in Note 5 to the consolidated financial statements, the circumstances set forth in Public Utility Regulation included in Item 1 of Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2017 and in Item 2 of Xcel Energy Inc.’s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

NSP-Minnesota

Wind Development — In 2017, the MPUC approved NSP-Minnesota’s proposal to add 1,550 megawatts (MW) of new wind generation including ownership of 1,150 MW of wind generation. An order from the NDPSC is expected later in 2018.

Dakota Range — In April 2018, the MPUC approved NSP-Minnesota’s petition to build and own the Dakota Range, a 300 MW wind project in South Dakota. The project is expected to be placed into service by the end of 2021 and qualify for 80 percent of the PTC. NSP-Minnesota’s total capital investment for the Dakota Range is expected to be approximately $350 million. A NDPSC decision is expected later in 2018.

Minnesota State Right-Of-First Refusal (ROFR) Statute Complaint — In September 2017, LSP Transmission Holdings, LLC (LSP Transmission) filed a complaint in the U.S. District Court for the District of Minnesota (Minnesota District Court) against the Minnesota Attorney General, the MPUC and the DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from near Mankato, Minn. to Winnebago, Minn. The project was estimated by MISO to cost $108 million, with the transmission line portion of the project estimated by MISO to cost $103 million. The project was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss. In June 2018, the Minnesota District Court granted the defendants’ motions to dismiss with prejudice. LSP Transmission filed an appeal to the 8th Circuit Court of Appeals in July 2018. It is uncertain when a decision will be rendered regarding this appeal.

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. See Note 14 to the consolidated financial statements of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2017 for further discussion regarding the nuclear generating plants. The circumstances set forth in Nuclear Power Operations included in Item 2 of Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated herein by reference.

NSP-Wisconsin

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse to Madison, Wis. Transmission Line — In 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a certificate of public convenience and necessity (CPCN) for a 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. NSP-Wisconsin's half of the line will be shared with three co-owners, Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

In 2015, the PSCW approved a CPCN and route for the project. Two groups appealed the CPCN order to the La Crosse County Circuit Court (Circuit Court). In May 2017, the Circuit Court issued its decision and the parties appealed aspects of the case to the Wisconsin Court of Appeals. In May 2018, the Wisconsin Court of Appeals concluded the PSCW utilized a rational basis in determining the need for construction along the contested seven-mile portion of the new transmission line. No further appeals are anticipated. The 180-mile project is expected to cost approximately $541 million. NSP-Wisconsin's portion of the investment, which includes AFUDC, is estimated to be approximately $200 million. Construction on the line began in January 2016, with completion anticipated by late 2018.

PSCo

Colorado Energy Plan (CEP) — In 2016, PSCo filed its 2016 Electric Resource Plan (ERP) which included the estimated need for additional generation resources through spring of 2024. In 2017, PSCo filed an updated capacity need with the CPUC of 450 MW in 2023.

In 2017, PSCo and various other stakeholders filed a stipulation agreement proposing the CEP, an alternative plan that increases PSCo's potential capacity need up to 1,110 MW due to the proposed retirement of two coal units.

In June 2018, PSCo filed its 120-day update report with the CPUC which includes multiple portfolios and recommends a preferred CEP portfolio. PSCo's investment under the preferred CEP portfolio would be approximately $1 billion, including investment in transmission to support the significant increase in renewable generation in the state. The preferred CEP portfolio includes the following additions as well as the retirement of the two coal-fired generation units:

	Total Capacity	PSCo's Ownership
Wind generation	1,100 MW	500 MW
Solar generation	700 MW	—
Battery storage	275 MW	—
Natural gas generation	380 MW	380 MW

On July 13, 2018, the Independent Evaluator (IE) for the ERP filed their report on the process, modeling and evaluation of the various offers received through the RFP process. Generally, the IE report was favorable to the process employed and the outcomes included in the modeling. Certain recommendations for future ERP processes were provided with a primary focus regarding enhanced modeling of new resource types such as battery storage.

On July 23, 2018, various stakeholders commented on the 120-day update report for the ERP and the CEP. Many community, advocate and developer interests supported the CEP, while certain stakeholders opposed the CEP and the associated early coal plant retirements. The CPUC staff indicated that PSCo's preferred CEP plan is a valid option, but expressed concerns on the saving assumptions, complexity of modeling and the utilization of production tax credits.

A CPUC decision is anticipated in September 2018.

Public Utility Regulatory Policies Act (PURPA) Enforcement Complaint against CPUC — Sustainable Power Group, LLC (sPower) has proposed to construct over 1,500 MW of solar and wind generation in Colorado and is seeking to require PSCo to contract for these resources under PURPA. In March 2017, sPower filed a complaint for declaratory and injunctive relief in the United States District Court for the District of Colorado (District Court) requesting that the court find a December 2016 CPUC ruling that a qualifying facility must be a successful bidder in a PSCo resource acquisition bidding process violated PURPA and FERC rules. In June 2018, the court denied a motion by the CPUC to dismiss. The case remains pending further action from the court.

Open Access Transmission Tariff (OATT) Reform — In May 2018, the FERC denied a request by PSCo to amend its OATT to allow large generating interconnection agreements to be suspended by the generator only due to a force majeure event, rather than allowing suspension for up to 36 months for any reason. PSCo requested the changes to facilitate more efficient processing of generator interconnection requests. PSCo has initiated a process to achieve broader generator interconnection queue reform and anticipates requesting additional OATT changes later in 2018. In April 2018, the FERC had issued a final rule requiring generator interconnection OATT queue reforms in addition (but generally complimentary) to reforms PSCo already requested. PSCo currently has more than 22,000 MW of new generator projects in its interconnection queue. The broader interconnection queue reforms are intended to allow generators to proceed to interconnection on a “first ready, first served” basis, similar to the processes already use in MISO.

Boulder, Colorado Municipalization — In 2011, City of Boulder, Colorado (Boulder) voters passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Since that time, there have been various legal proceedings in multiple venues with jurisdiction over Boulder’s plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility as premature and the Colorado Court of Appeals ruled in PSCo’s favor, vacating a lower court decision. In June 2018, the Colorado Supreme Court rejected Boulder’s request to dismiss the case and ruled that the case be remanded for hearing at the Boulder District Court (District Court).

Boulder has filed multiple separation applications with the CPUC, which have been challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo’s position. The CPUC approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain filings. In July 2018, the CPUC approved Boulder and PSCo’s joint request to extend the time by which these filings would be due until Aug. 24, 2018. Boulder does not have authorization from the CPUC to initiate a condemnation proceeding at this time.

SPS

Texas State ROFR Request for Declaratory Order — In February 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS’ ROFR. SPS contended that Texas law grants an incumbent electric utility, operating in areas outside of Electric Reliability Council of Texas, the ROFR to construct new transmission facilities located in the utility’s service area. SPP stated that Texas law does not provide a clear statement regarding the ROFR for incumbent utilities and therefore SPP was abiding by the portion of its OATT, which requires competitive solicitation to construct and operate new transmission facilities within areas of Texas’ SPP footprint.

In October 2017, the PUCT issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities within its service area. In January 2018, SPS and two other parties filed appeals of the PUCT’s order in the Texas State District Court. The appeals have been consolidated and the case is being briefed.

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — SPS has received certificates of convenience and necessity for the three segments of the TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV transmission line, which are expected to be in service in the second quarter of 2020. This 345 KV transmission line is part of a larger project which includes an additional 345 KV transmission line from the Hobbs Plant Substation to the China Draw Substation, which was placed in service in May 2018. The estimated total investment for these transmission lines is approximately $402 million.

Wind Proposals — In 2017, SPS filed proposals with the NMPRC and the PUCT to build, own and operate 1,000 MW of new wind generation through two wind farms (the Hale wind project in Texas and the Sagamore wind project in New Mexico) for a cost of approximately $1.6 billion. In addition, the proposal includes a purchased power agreement for 230 MW of wind. SPS’ wind proposal was approved by both the NMPRC and the PUCT during 2018.

Summary of Recent Federal Regulatory Developments

FERC

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries and transmission-only subsidiaries, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2017 and Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

Derivatives, Risk Management and Market Risk

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

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

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

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

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, 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.

At June 30, 2018, the fair values by source for net commodity trading contract assets were as follows:

		Futures / Forwards				
(Millions of Dollars)	**Source of Fair Value**	**Maturity Less Than 1 Year**	**Maturity 1 to 3 Years**	**Maturity 4 to 5 Years**	**Maturity Greater Than 5 Years**	**Total Futures/ Forwards Fair Value**
NSP-Minnesota	1	$ 2	$ 8	$ —	$ —	$ 10
NSP-Minnesota	2	2	—	1	3	6
PSCo	1	1	—	—	—	1
		$ 5	$ 8	$ 1	$ 3	$ 17

1 — Prices actively quoted or based on actively quoted prices.

2 — Prices based on models and other valuation methods.

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

	Six Months Ended June 30	
(Millions of Dollars)	2018	2017
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 16	$ 10
Contracts realized or settled during the period	(4)	(6)
Commodity trading contract additions and changes during the period	5	11
Fair value of commodity trading net contract assets outstanding at June 30	$ 17	$ 15

At June 30, 2018, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income from continuing operations by an immaterial amount, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $1 million. At June 30, 2017, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by an immaterial amount, whereas a 10 percent decrease would decrease pretax income from continuing operations by an immaterial amount.

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

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

(Millions of Dollars)	Three Months Ended June 30	VaR Limit	Average	High	Low
2018	$ 0.11	$ 3.00	$ 0.16	$ 0.44	$ 0.06
2017	0.26	3.00	0.38	0.66	0.04

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 58 percent of its 2018 and approximately 24 percent of its 2019 enriched nuclear material requirements from sources that could be impacted by current political/world events, including those related to Ukraine/Russia. Alternate potential sources are expected to provide the flexibility to manage NSP-Minnesota’s nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 34 percent of its average enriched nuclear material requirements from these sources. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material.

Separately, NSP-Minnesota has enriched nuclear fuel materials in process with Westinghouse Electric Corporation (Westinghouse). Westinghouse filed for Chapter 11 bankruptcy protection in March 2017. NSP-Minnesota owns materials in Westinghouse’s inventory and has contracts in place under which Westinghouse will provide certain services during an upcoming outage at PI. Westinghouse will provide nuclear fuel assemblies for the upcoming PI outage under the current nuclear fuel fabrication contract. Westinghouse has indicated its intention to continue to perform under the arrangements. Based on Westinghouse’s stated intent and the interim financing secured to fund its on-going operations, NSP-Minnesota does not expect the bankruptcy to materially impact NSP-Minnesota’s operational or financial performance. Westinghouse announced on Jan. 4, 2018 it has agreed to be acquired by Brookfield Business Partners LP and other institutional partners. Brookfield’s acquisition of Westinghouse is expected to close in the third quarter of 2018, subject to bankruptcy court and regulatory approvals. NSP-Minnesota will continue to monitor the Westinghouse acquisition process.

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

At June 30, 2018 and 2017, a 100-basis-point change in the benchmark rate on Xcel Energy’s variable rate debt would impact pretax interest expense annually by approximately $8 million and $9 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries’ interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At June 30, 2018, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings.

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

At June 30, 2018, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $24 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $6 million. At June 30, 2017, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $18 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $2 million.

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

Fair Value Measurements

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

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at June 30, 2018. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as other comprehensive income or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at June 30, 2018.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 2.6 percent and 5.5 percent of total assets and liabilities, respectively, measured at fair value at June 30, 2018.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited transparency in the auction process, fair value measurements for FTRs have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $59 million and $1 million of estimated fair values, respectively, for FTRs held at June 30, 2018.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were $5 million in Level 3 commodity derivative assets and $2 million of liabilities for options held at June 30, 2018. There were $3 million of Level 3 derivative assets held as forwards at June 30, 2018.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	Six Months Ended June 30 2018	Six Months Ended June 30 2017
Cash provided by operating activities	$ 1,437	$ 1,292

Net cash provided by operating activities increased $145 million for the six months ended June 30, 2018 compared with the six months ended June 30, 2017. The increase was primarily due to the timing of recovery of certain electric and natural gas riders and vendor payments, partially offset by lower net income, excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expense) and the timing of customer refunds.

(Millions of Dollars)	Six Months Ended June 30 2018	Six Months Ended June 30 2017
Cash used in investing activities	$ (1,865)	$ (1,474)

Net cash used in investing activities increased $391 million for the six months ended June 30, 2018 compared with the six months ended June 30, 2017. The increase was primarily attributable to higher capital expenditures related to the Rush Creek and Hale wind generation facilities.

(Millions of Dollars)	Six Months Ended June 30 2018	Six Months Ended June 30 2017
Cash provided by financing activities	$ 677	$ 159

Net cash provided by financing activities increased $518 million for the six months ended June 30, 2018 compared with the six months ended June 30, 2017. The increase was primarily attributable to higher net proceeds from short and long-term debt.

Capital Requirements

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

Regulation of Derivatives — In 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. The Commodity Futures Trading Commission ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. The de minimis threshold is scheduled to be reduced to $3 billion at the end of 2019. Xcel Energy’s current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that exempt certain derivatives end users from much of the clearing and margin requirements and Xcel Energy’s Board of Directors has renewed the end-user exemption on an annual basis. Xcel Energy currently meets its reporting requirements and transaction restrictions.

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

- In January 2018, contributions of $150 million were made across four of Xcel Energy’s pension plans;
- In 2017, contributions of $162 million were made across four of Xcel Energy’s pension plans; and
- For future years, contributions will be made as deemed appropriate based on evaluation of various factors including the funded status of the plans, minimum funding requirements, interest rates and expected investment returns.

Capital Sources

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

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At June 30, 2018, approximately $275 million of cash was held in these accounts.

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the five-year credit facilities is $2.75 billion, and each credit facility terminates in June 2021. NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving credit facility termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

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

As of July 23, 2018, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,250	$ 464	$ 786	$ 1	$ 787
PSCo	700	4	696	174	870
NSP-Minnesota	500	37	463	1	464
SPS	400	144	256	1	257
NSP-Wisconsin	150	48	102	1	103
Total	$ 3,000	$ 697	$ 2,303	$ 178	$ 2,481

(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.

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

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

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

Short-term debt outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 3,000	$ 3,250
Amount outstanding at period end	682	814
Average amount outstanding	1,028	644
Maximum amount outstanding	1,349	1,247
Weighted average interest rate, computed on a daily basis	2.42%	1.35%
Weighted average interest rate at period end	2.47	1.90

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

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

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

During 2018, Xcel Energy Inc. and its utility subsidiaries issued and anticipate issuing 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;
- NSP-Wisconsin plans to issue approximately $200 million of first mortgage bonds; and
- SPS plans to issue approximately $250 million of first mortgage bonds.

Xcel Energy also plans to issue approximately $300 million of incremental equity in 2018 in addition to $75 million of equity to be issued through the dividend reinvestment program and benefit programs.

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

Off-Balance-Sheet Arrangements

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

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

Xcel Energy 2018 Earnings Guidance — Xcel Energy revised upward its 2018 guidance range to $2.41 to $2.51 per share from its previous 2018 guidance range of $2.37 to $2.47 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the remainder of the year.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 1.0 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to increase 1.0 percent to 1.5 percent over 2017 levels.
- Capital rider revenue is projected to increase $40 million to $50 million over 2017 levels. PTCs are flowed back to customers, primarily through capital riders and reductions to electric margin.
- O&M expenses are projected to increase 1 percent to 2 percent over 2017 levels.
- Depreciation expense is projected to increase approximately $100 million to $110 million over 2017 levels.
- Property taxes are projected to increase approximately $10 million to $20 million over 2017 levels.
- Interest expense (net of AFUDC - debt) is projected to increase $30 million to $40 million over 2017 levels.
- AFUDC - equity is projected to increase approximately $20 million to $30 million from 2017 levels.
- The ETR is projected to be approximately 15 percent to 17 percent. This range may decrease to 8 percent to 10 percent as we receive clarity and direction from our commissions as to the treatment of excess deferred taxes that resulted from the TCJA. A reduction to the ETR resulting from the flowback of excess deferred taxes would be offset by a correlated reduction to revenue. Additionally, the lower ETR for 2018 compared to 2017 reflects additional PTCs which are flowed back to customers through margin.

(a) Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations. Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing diluted EPS to corresponding GAAP diluted EPS.

Long-Term EPS and Dividend Growth Rate Objectives — Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 5 percent to 6 percent off of a 2017 base of $2.30 per share;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of June 30, 2018, based on an evaluation carried out under the supervision and with the participation of Xcel Energy’s management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy’s disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

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

Additional Information

See Note 6 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Part I Item 2 and Note 5 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 1A — RISK FACTORS

Xcel Energy Inc.’s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2017, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended June 30, 2018:

	Issuer Purchases of Equity Securities			
Period	**Total Number of Shares Purchased**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs**
April 1, 2018 — April 30, 2018	—	$ —	—	—
May 1, 2018 — May 31, 2018	—	—	—	—
June 1, 2018 — June 30, 2018	—	—	—	—
Total	—		—	—

Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 18, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Bylaws of Xcel Energy Inc., as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K filed Feb. 18, 2016 (file no. 001-03034)).
4.01*	Supplemental Indenture No. 11, dated as of June 25, 2018 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $500 million in aggregate principal amount of 4.00 percent Senior Notes, Series due June 15, 2028 (Exhibit 4.01 to Form 8-K dated June 25, 2018 (file no. 001-03034)).
4.02*	Supplemental Indenture dated as of June 1, 2018, between Public Service Company of Colorado and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70 percent First Mortgage Bonds, Series No. 31 due 2028, and $350 million principal amount of 4.10 percent First Mortgage Bonds, Series No. 32 due 2048 (Exhibit 4.01 to Form 8-K of PSCo filed June 21, 2018 (file no. 001-03280)).
10.01	Seventh Amendment dated May 7, 2018 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy.
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

SIGNATURES

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

XCEL ENERGY INC.

July 27, 2018

By: /s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

(Back To Top)

Section 2: EX-10.01 (EXHIBIT 10.01)

Exhibit 10.01

Seventh Amendment
to the
Xcel Energy Senior Executive Severance and Change-In-Control Policy

THIS SEVENTH AMENDMENT is made this 7th day of May, 2018, by Xcel Energy Inc. (the “Principal Sponsor”).

WITNESSETH:

WHEREAS, the Principal Sponsor maintains the Xcel Energy Senior Executive Severance and Change-In-Control Policy (the “Policy”), and

WHEREAS, the Board of Directors of the Principal Sponsor (the “Board”) has reserved the right to make amendments to the Policy, and

WHEREAS, the Governance, Compensation and Nominating Committee of the Board of Directors of the Principal Sponsor (the “Committee”) has reserved the right to appoint or remove Participants under the Policy, and

WHEREAS, the Committee wishes to amend the Policy in certain respects to add a Participant to Schedule I to be effective May 7, 2018.

NOW, THEREFORE, the Policy is hereby amended as follows:

1. **Schedule I - Participants:** Schedule I to the Policy is hereby amended to add Brett Carter to the Schedule as a Tier I Participant as follows:

Name	Tier	Severance Multiple	Change-in-Control Multiple
Brett Carter	1	1	3

2. **Savings Clause.** Except as hereinabove set forth, the Xcel Energy Senior Executive Severance and Change-In-Control Policy shall continue in full force and effect.

IN WITNESS WHEREOF, Xcel Energy Inc. has caused this instrument to be enacted by its duly authorized officer as of the date set forth to be effective May 7, 2018.

XCEL ENERGY INC.

By: /s/ Darla Figoli___________________

Its: _Chief Human Resources Officer__

(Back To Top)

Section 3: EX-31.01 (EXHIBIT 31.01)

Exhibit 31.01

CERTIFICATION

I, Ben Fowke, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: July 27, 2018

/s/ BEN FOWKE

Ben Fowke

Chairman, President, Chief Executive Officer and Director

(Principal Executive Officer)

(Back To Top)

Section 4: EX-31.02 (EXHIBIT 31.02)

Exhibit 31.02

CERTIFICATION

I, Robert C. Frenzel, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: July 27, 2018

/s/ ROBERT C. FRENZEL

Robert C. Frenzel

Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

(Back To Top)

Section 5: EX-32.01 (EXHIBIT 32.01)

Exhibit 32.01

OFFICER CERTIFICATION

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

In connection with the Quarterly Report of Xcel Energy Inc. (Xcel Energy) on Form 10-Q for the quarter ended June 30, 2018, as filed with the SEC on the date hereof (Form 10-Q), each of the undersigned officers of Xcel Energy certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

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

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

Date: July 27, 2018

/s/ BEN FOWKE
Ben Fowke
Chairman, President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

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

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

(Back To Top)

Section 6: EX-99.01 (EXHIBIT 99.01)

Exhibit 99.01

XCEL ENERGY CAUTIONARY FACTORS

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

- Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;
- The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;
- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where Xcel Energy has a financial interest;
- Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the FERC and similar entities with regulatory oversight;
- Availability of cost or capital such as changes in: interest rates; market perceptions of the utility industry, Xcel Energy Inc. or any of its subsidiaries; or security ratings;
- Factors affecting utility and nonutility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel, nuclear fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; nuclear or environmental incidents; cyber incidents; or electric transmission or natural gas pipeline constraints;
- Employee workforce factors, including loss or retirement of key executives, collective-bargaining agreements with union employees, or work stoppages;
- Increased competition in the utility industry or additional competition in the markets served by Xcel Energy Inc. and its subsidiaries;
- State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric and natural gas markets; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Environmental laws and regulations, including legislation and regulations relating to climate change, and the associated cost of compliance;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;
- Nuclear regulatory policies and procedures, including operating regulations and spent nuclear fuel storage;
- Social attitudes regarding the utility and power industries;
- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;
- Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;
- Risks associated with implementations of new technologies; and
- Other business or investment considerations that may be disclosed from time to time in Xcel Energy Inc.'s SEC filings, including "Risk Factors" in Item 1A of Xcel Energy's Form 10-K for the year ended Dec. 31, 2017, or in other publicly disseminated written documents.

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

(Back To Top)