XCEL ENERGY INC
Form 10-Q
July 27, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended 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. x Yes ¨ No

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

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

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

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

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

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

Class	Outstanding at July 23, 2018
Common Stock, $2.50 par value	509,087,107 shares

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

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PART I — FINANCIAL INFORMATION

Item 1 — FINANCIAL STATEMENTS

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

	Three Months Ended 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

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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

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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

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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

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
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

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

	Common Stock Issued				Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Other Comprehensive Loss	Common Stockholders' Equity
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

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

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of 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.

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Presentation of Net Periodic Benefit Cost — In March 2017, the FASB issued Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07), which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. As a result of the application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment, and the impacts of adoption will be limited to changes in classification of non-service costs in the consolidated statement of income. Xcel Energy implemented the new guidance on Jan. 1, 2018, and as a result, $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.

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

	Three Months Ended 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.

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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.

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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.

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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.

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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.

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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.

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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