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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, 2022

or

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

For the transition period from to

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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $2.50 par value	XEL	Nasdaq Stock Market LLC

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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 ☐
	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 21, 2022
Common Stock, $2.50 par value	546,991,330 shares

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This Form 10-Q is filed by Xcel Energy Inc. Additional information is available in various filings with the SEC. This report should be read in its entirety.

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
e prime	e prime inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies	
CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OAG	Minnesota Office of Attorney General
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses	
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PSIA	Pipeline System Integrity Adjustment
RES	Renewable energy standard
TCR	Transmission cost recovery adjustment

Other	
ACE	Affordable Clean Energy
AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
ATM	At-the-market
BART	Best available retrofit technology
C&I	Commercial and Industrial
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CDD	Cooling degree-days
CEO	Chief executive officer
CFO	Chief financial officer
CORE	CORE Electric Cooperative
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CSPV	Crystalline Silicon Photovoltaic
CUB	Citizens Utility Board
DRIP	Dividend Reinvestment and Stock Purchase Program
EPS	Earnings per share
ETR	Effective tax rate
FTR	Financial transmission right
GAAP	United States generally accepted accounting principles
GE	General Electric Company
HDD	Heating degree-days
IPP	Independent power producing entity
LLC	Limited liability company
LP&L	Lubbock Power and Light
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
NAV	Net asset value
NOPR	Notice of Proposed Rulemaking
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
PIM	Performance Incentive Mechanism
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
RTO	Regional Transmission Organization
SMMPA	Southern Minnesota Municipal Power Agency
SPP	Southwest Power Pool, Inc.
THI	Temperature-humidity index
TOs	Transmission owners
UCA	Colorado Office of the Utility Consumer Advocate
VaR	Value at Risk

Measurements	
MW	Megawatts

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 those relating to 2022 EPS guidance, long-term EPS and dividend growth rate objectives, future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, 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 in Xcel Energy's Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 and subsequent filings with the SEC, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including potential workforce impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety, including our nuclear generation facilities and other utility operations; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; ability to recover costs, changes in regulation and subsidiaries' ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints and their impact on capital expenditures and/or the ability of Xcel Energy to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties; and regulatory changes and/or limitations related to the use of natural gas as an energy source.

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	
	2022	2021	2022	2021
Operating revenues				
Electric	$ 2,923	$ 2,597	$ 5,556	$ 5,467
Natural gas	476	449	1,566	1,096
Other	25	22	53	46
Total operating revenues	3,424	3,068	7,175	6,609
Operating expenses				
Electric fuel and purchased power	1,181	1,047	2,275	2,433
Cost of natural gas sold and transported	251	218	961	517
Cost of sales — other	11	9	21	17
O&M expenses	614	600	1,216	1,184
Conservation and demand side management expenses	81	71	173	144
Depreciation and amortization	638	528	1,200	1,049
Taxes (other than income taxes)	179	157	350	320
Total operating expenses	2,955	2,630	6,196	5,664
Operating income	469	438	979	945
Other (expense) income, net	(6)	3	(5)	8
Earnings from equity method investments	11	20	26	34
Allowance for funds used during construction — equity	20	18	33	32
Interest charges and financing costs				
Interest charges — includes other financing costs of $8, $7, $16 and $14, respectively	247	212	461	417
Allowance for funds used during construction — debt	(7)	(6)	(12)	(11)
Total interest charges and financing costs	240	206	449	406
Income before income taxes	254	273	584	613
Income tax benefit	(74)	(38)	(124)	(60)
Net income	$ 328	$ 311	$ 708	$ 673
Weighted average common shares outstanding:				
Basic	546	539	545	539
Diluted	546	539	546	539
Earnings per average common share:				
Basic	$ 0.60	$ 0.58	$ 1.30	$ 1.25
Diluted	0.60	0.58	1.30	1.25

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	
	2022	2021	2022	2021
Net income	$ 328	$ 311	$ 708	$ 673
Other comprehensive income				
Pension and retiree medical benefits:				
Reclassifications of loss to net income, net of tax of $—, $—, $1 and $1, respectively	1	1	2	1
Derivative instruments:				
Net fair value increase, net of tax of $4, $—, $6 and $—, respectively	11	—	16	—
Reclassification of losses to net income, net of tax of $—, $—, $1 and $1, respectively	1	2	2	5
Total other comprehensive income	13	3	20	6
Total comprehensive income	$ 341	$ 314	$ 728	$ 679

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	
	2022	2021
Operating activities		
Net income	$ 708	$ 673
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	1,210	1,043
Nuclear fuel amortization	61	56
Deferred income taxes	(135)	(67)
Allowance for equity funds used during construction	(33)	(32)
Earnings from equity method investments	(26)	(34)
Dividends from equity method investments	20	21
Provision for bad debts	30	27
Share-based compensation expense	14	21
Changes in operating assets and liabilities:		
Accounts receivable	(97)	(63)
Accrued unbilled revenues	70	14
Inventories	(44)	7
Other current assets	26	24
Accounts payable	137	(15)
Net regulatory assets and liabilities	213	(794)
Other current liabilities	(134)	(265)
Pension and other employee benefit obligations	(32)	(128)
Other, net	—	1
Net cash provided by operating activities	1,988	489
Investing activities		
Capital/construction expenditures	(2,040)	(1,967)
Purchase of investment securities	(787)	(628)
Proceeds from the sale of investment securities	769	410
Other, net	3	(17)
Net cash used in investing activities	(2,055)	(2,202)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(869)	1,161
Proceeds from issuances of long-term debt	2,066	1,821
Repayments of long-term debt, including reacquisition premiums	(600)	(399)
Proceeds from issuance of common stock	151	11
Dividends paid	(497)	(460)
Other, net	(15)	(12)
Net cash provided by financing activities	236	2,122
Net change in cash, cash equivalents and restricted cash	169	409
Cash, cash equivalents and restricted cash at beginning of period	166	129
Cash, cash equivalents and restricted cash at end of period	$ 335	$ 538
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (425)	$ (390)
Cash paid for income taxes, net	(9)	(5)
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 401	$ 509
Inventory transfers to property, plant and equipment	30	43
Operating lease right-of-use assets	15	1
Allowance for equity funds used during construction	33	32
Issuance of common stock for reinvested dividends and/or equity awards	27	35

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, 2022	Dec. 31, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 335	$ 166
Accounts receivable, net	1,084	1,018
Accrued unbilled revenues	792	862
Inventories	645	631
Regulatory assets	1,085	1,106
Derivative instruments	534	123
Prepaid taxes	51	44
Prepayments and other	316	289
Total current assets	4,842	4,239
Property, plant and equipment, net	46,535	45,457
Other assets		
Nuclear decommissioning fund and other investments	3,229	3,628
Regulatory assets	2,965	2,738
Derivative instruments	105	67
Operating lease right-of-use assets	1,202	1,291
Other	439	431
Total other assets	7,940	8,155
Total assets	$ 59,317	$ 57,851
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 651	$ 601
Short-term debt	136	1,005
Accounts payable	1,590	1,409
Regulatory liabilities	682	271
Taxes accrued	415	569
Accrued interest	219	209
Dividends payable	266	249
Derivative instruments	142	69
Operating lease liabilities	210	205
Other	554	459
Total current liabilities	4,865	5,046
Deferred credits and other liabilities		
Deferred income taxes	4,708	4,894
Deferred investment tax credits	51	53
Regulatory liabilities	5,498	5,405
Asset retirement obligations	3,271	3,151
Derivative instruments	120	105
Customer advances	184	196
Pension and employee benefit obligations	259	306
Operating lease liabilities	1,047	1,146
Other	138	158
Total deferred credits and other liabilities	15,276	15,414
Commitments and contingencies		
Capitalization		
Long-term debt	23,205	21,779
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 546,807,793 and 544,025,269 shares outstanding at June 30, 2022 and Dec. 31, 2021, respectively	1,367	1,360
Additional paid in capital	7,960	7,803
Retained earnings	6,747	6,572
Accumulated other comprehensive loss	(103)	(123)
Total common stockholders' equity	15,971	15,612
Total liabilities and equity	$ 59,317	$ 57,851

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in millions, except per share data; shares in actual amounts)

	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, 2022 and 2021						
Balance at March 31, 2021	538,076,662	$ 1,345	$ 7,411	$ 6,082	$ (138)	$ 14,700
Net income				311		311
Other comprehensive income					3	3
Dividends declared on common stock ($0.4575 per share)				(246)		(246)
Issuances of common stock	229,265	1	14			15
Share-based compensation			10	(1)		9
Balance at June 30, 2021	538,305,927	$ 1,346	$ 7,435	$ 6,146	$ (135)	$ 14,792
Balance at March 31, 2022	544,530,987	$ 1,361	$ 7,801	$ 6,686	$ (116)	$ 15,732
Net income				328		328
Other comprehensive income					13	13
Dividends declared on common stock ($0.4875 per share)				(266)		(266)
Issuances of common stock	2,276,806	6	153			159
Share-based compensation			6	(1)		5
Balance at June 30, 2022	546,807,793	$ 1,367	$ 7,960	$ 6,747	$ (103)	$ 15,971

	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, 2022 and 2021						
Balance at Dec. 31, 2020	537,438,394	$ 1,344	$ 7,404	$ 5,968	$ (141)	$ 14,575
Net income				673		673
Other comprehensive loss					6	6
Dividends declared on common stock ($0.915 per share)				(492)		(492)
Issuances of common stock	867,533	2	28			30
Share-based compensation			3	(3)		—
Balance at June 30, 2021	538,305,927	$ 1,346	$ 7,435	$ 6,146	$ (135)	$ 14,792
Balance at Dec. 31, 2021	544,025,269	$ 1,360	$ 7,803	$ 6,572	$ (123)	$ 15,612
Net income				708		708
Other comprehensive income					20	20
Dividends declared on common stock ($0.975 per share)				(531)		(531)
Issuances of common stock	2,782,524	7	164			171
Share-based compensation			(7)	(2)		(9)
Balance at June 30, 2022	546,807,793	$ 1,367	$ 7,960	$ 6,747	$ (103)	$ 15,971

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 GAAP, the financial position of Xcel Energy as of June 30, 2022 and Dec. 31, 2021; the results of Xcel Energy's operations, including the components of net income, comprehensive income, and changes in stockholders' equity for the six months ended June 30, 2022 and 2021; and Xcel Energy's cash flows for the six months ended June 30, 2022 and 2021.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2022, 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, 2021 balance sheet information has been derived from the audited 2021 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2021.

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, 2021, filed with the SEC on Feb. 23, 2022.

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, 2021 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

As of June 30, 2022, there was no material impact from the recent adoption of new accounting pronouncements, nor expected material impact from recently issued accounting pronouncements yet to be adopted, on Xcel Energy's consolidated financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	June 30, 2022	Dec. 31, 2021
Accounts receivable, net		
Accounts receivable	$ 1,195	$ 1,124
Less allowance for bad debts	(111)	(106)
Accounts receivable, net	$ 1,084	$ 1,018

(Millions of Dollars)	June 30, 2022	Dec. 31, 2021
Inventories		
Materials and supplies	$ 309	$ 289
Fuel	216	182
Natural gas	120	160
Total inventories	$ 645	$ 631

(Millions of Dollars)	June 30, 2022	Dec. 31, 2021
Property, plant and equipment, net		
Electric plant	$ 48,445	$ 48,680
Natural gas plant	8,029	7,758
Common and other property	2,769	2,602
Plant to be retired [(a)]	2,310	1,200
Construction work in progress	2,056	1,969
Total property, plant and equipment	63,609	62,209
Less accumulated depreciation	(17,336)	(17,060)
Nuclear fuel	3,096	3,081
Less accumulated amortization	(2,834)	(2,773)
Property, plant and equipment, net	$ 46,535	$ 45,457

(a) Amounts as of Dec. 31, 2021 include Sherco Units 1, 2 and 3 and A.S. King for NSP-Minnesota; Comanche Unit 1 and 2 and Craig Units 1 and 2 for PSCo; and Tolk and coal generation assets at Harrington pending facility gas conversion for SPS. Following the June 2022 approval of PSCo's revised resource plan settlement, amounts as of June 30, 2022 include the addition of Comanche Unit 3, Hayden Units 1 and 2 and coal generation assets at Pawnee pending facility gas conversion. Amounts are presented net of accumulated depreciation.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

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:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 3,100	$ 3,100
Amount outstanding at period end	136	1,005
Average amount outstanding	554	1,399
Maximum amount outstanding	1,136	2,054
Weighted average interest rate, computed on a daily basis	1.05 %	0.57 %
Weighted average interest rate at period end	1.90	0.31

Letters of Credit — Xcel Energy Inc. and its utility subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain obligations. There were $39 million and $19 million of letters of credit outstanding under the credit facilities at June 30, 2022 and Dec. 31, 2021, respectively. Amounts approximate their fair value and are subject to fees.

Revolving Credit Facilities — In order to issue commercial paper, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities at least equal to the amount of commercial paper borrowing limits and cannot issue commercial paper exceeding available credit facility capacity. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

As of June 30, 2022, Xcel Energy Inc. and its utility subsidiaries had the following committed revolving credit facilities available:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available
Xcel Energy Inc.	$ 1,250	$ 136	$ 1,114
PSCo	700	26	674
NSP-Minnesota	500	11	489
SPS	500	2	498
NSP-Wisconsin	150	—	150
Total	$ 3,100	$ 175	$ 2,925

(a) Expires in June 2024.
(b) Includes outstanding commercial paper and letters of credit.

Xcel Energy Inc., NSP-Minnesota, PSCo, and SPS each have the right to request an extension of the credit facility termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available credit facilities capacity. Xcel Energy Inc. and its utility subsidiaries had no direct advances on the credit facilities outstanding as of June 30, 2022 and Dec. 31, 2021.

Bilateral Credit Agreement

In April 2022, NSP-Minnesota's uncommitted bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of June 30, 2022, NSP-Minnesota had $43 million of outstanding letters of credit under the $75 million bilateral credit agreement.

Long-Term Borrowings and Other Financing Instruments

During the six months ended June 30, 2022, Xcel Energy Inc. and its utility subsidiaries issued the following:

- Xcel Energy issued $700 million of 4.60% unsecured senior notes due June 1, 2032.
- NSP-Minnesota issued $500 million of 4.50% first mortgage bonds due June 1, 2052.
- PSCo issued $300 million of 4.10% first mortgage bonds due June 1, 2032 and $400 million of 4.50% first mortgage bonds due June 1, 2052.
- SPS issued $200 million of 5.15% first mortgage bonds due June 1, 2052.

On July 15, 2022, subsequent to the end of the quarter, NSP-Wisconsin priced a private placement of $100 million of 4.86% first mortgage bonds due September 15, 2052. The closing of the sale of the bonds is expected to occur on Sept. 12, 2022.

ATM Equity Offering — In November 2021, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $800 million of its common stock through an ATM program. In 2021, 5.33 million shares had been issued (approximately $350 million). In the second quarter of 2022, 2.13 million shares of common stock were issued (approximately $150 million). As of June 30, 2022, approximately $300 million remained available under the ATM program.

Other Equity — Xcel Energy Inc. issued $20 million and $28 million of equity through the DRIP during the six months ended June 30, 2022 and 2021, respectively. The program allows shareholders to reinvest their dividends directly in Xcel Energy Inc. common stock.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. Xcel Energy's operating revenues consisted of the following:

	Three Months Ended June 30, 2022			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 797	$ 257	$ 6	$ 1,060
C&I	1,416	164	7	1,587
Other	37	—	9	46
Total retail	2,250	421	22	2,693
Wholesale	318	—	—	318
Transmission	156	—	—	156
Other	12	37	—	49
Total revenue from contracts with customers	2,736	458	22	3,216
Alternative revenue and other	187	18	3	208
Total revenues	$ 2,923	$ 476	$ 25	$ 3,424

	Three Months Ended June 30, 2021			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 756	$ 257	$ 11	$ 1,024
C&I	1,282	126	6	1,414
Other	32	—	2	34
Total retail	2,070	383	19	2,472
Wholesale	234	—	—	234
Transmission	148	—	—	148
Other	20	42	—	62
Total revenue from contracts with customers	2,472	425	19	2,916
Alternative revenue and other	125	24	3	152
Total revenues	$ 2,597	$ 449	$ 22	$ 3,068

	Six Months Ended June 30, 2022			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,614	$ 919	$ 15	$ 2,548
C&I	2,651	520	9	3,180
Other	69	—	23	92
Total retail	4,334	1,439	47	5,820
Wholesale	577	—	—	577
Transmission	308	—	—	308
Other	35	82	—	117
Total revenue from contracts with customers	5,254	1,521	47	6,822
Alternative revenue and other	302	45	6	353
Total revenues	$ 5,556	$ 1,566	$ 53	$ 7,175

	Six Months Ended June 30, 2021			
(Millions of Dollars)	**Electric**	**Natural Gas**	**All Other**	**Total**
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,489	$ 642	$ 21	$ 2,152
C&I	2,315	312	15	2,642
Other	62	—	3	65
Total retail	3,866	954	39	4,859
Wholesale	977	—	—	977
Transmission	294	—	—	294
Other	34	61	—	95
Total revenue from contracts with customers	5,171	1,015	39	6,225
Alternative revenue and other	296	81	7	384
Total revenues	$ 5,467	$ 1,096	$ 46	$ 6,609

6. Income Taxes

Reconciliation between the statutory rate and ETR:

	Three Months Ended June 30		Six Months Ended June 30	
	2022	**2021**	**2022**	**2021**
Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %
State tax (net of federal tax effect)	5.2	4.9	5.0	4.9
Decreases:				
Wind PTCs [(a)]	(48.3)	(33.1)	(40.4)	(28.4)
Plant regulatory differences [(b)]	(5.5)	(6.6)	(5.1)	(6.3)
Other tax credits, net operating loss & tax credits allowances	(1.4)	(1.0)	(1.5)	(1.1)
Other (net)	(0.1)	0.9	(0.2)	0.1
Effective income tax rate	(29.1)%	(13.9)%	(21.2)%	(9.8)%

(a) Wind PTCs are credited to customers (reduction to revenue) and do not materially impact net income.

(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred taxes are offset by corresponding revenue reductions.

7. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the average weighted number of common shares outstanding. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding.

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 diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. has common stock equivalents 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 issued to employees 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 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.

Common shares outstanding used in the basic and diluted EPS computation:

	Three Months Ended June 30		Six Months Ended June 30	
(Shares in Millions)	**2022**	**2021**	**2022**	**2021**
Basic	546	539	545	539
Diluted [(a)]	546	539	546	539

(a) Diluted common shares outstanding included common stock equivalents of 0.3 million for the three months ended June 30, 2022 and 2021, respectively. Diluted common shares outstanding included common stock equivalents of 0.2 million and 0.3 million for the six months ended June 30, 2022 and 2021, respectively.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires 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.

- 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:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted 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. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund 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 commingled fund investments may be redeemed with proper notice, however, withdrawals 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 — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — 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 relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs 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 FTRs. FTRs purchased from an 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 values of these instruments are derived from, and designed to offset, the costs 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 these instruments. FTRs are recognized at estimated fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3.

If costs of electric transmission congestion increase or decrease for a given path, the value of that particular instrument will likewise increase or decrease. Net congestion costs, including the impact of FTR settlements, are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Non-Derivative Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the MPUC-approved asset allocation for the investment targets by asset class for the qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $1.0 billion and $1.3 billion as of June 30, 2022 and Dec. 31, 2021, respectively, and unrealized losses were $76 million and $7 million as of June 30, 2022 and Dec. 31, 2021, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

	June 30, 2022					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 53	$ 53	$ —	$ —	$ —	$ 53
Commingled funds	835	—	—	—	1,209	1,209
Debt securities	668	—	615	6	—	621
Equity securities	407	971	1	—	—	972
Total	$ 1,963	$ 1,024	$ 616	$ 6	$ 1,209	$ 2,855

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $220 million of equity method investments and $154 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2021					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 64	$ 64	$ —	$ —	$ —	$ 64
Commingled funds	856	—	—	—	1,294	1,294
Debt securities	631	—	666	9	—	675
Equity securities	411	1,222	1	—	—	1,223
Total	$ 1,962	$ 1,286	$ 667	$ 9	$ 1,294	$ 3,256

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $208 million of equity method investments and $164 million of rabbi trust assets and other miscellaneous investments.

For the three and six months ended June 30, 2022 and 2021, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of June 30, 2022:

	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
Debt securities	$ 3	$ 190	$ 232	$ 196	$ 621

Rabbi Trusts

Xcel Energy has established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan.

Cost and fair value of assets held in rabbi trusts:

	June 30, 2022				
		Fair Value			
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi Trusts [(a)]					
Cash equivalents	$ 20	$ 20	$ —	$ —	$ 20
Mutual funds	75	78	—	—	78
Total	$ 95	$ 98	$ —	$ —	$ 98

	Dec. 31, 2021				
		Fair Value			
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi Trusts [(a)]					
Cash equivalents	$ 20	$ 20	$ —	$ —	$ 20
Mutual funds	75	89	—	—	89
Total	$ 95	$ 109	$ —	$ —	$ 109

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

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 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, with changes in fair value prior to settlement recorded as other comprehensive income.

As of June 30, 2022, accumulated other comprehensive loss related to interest rate derivatives included $4 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of June 30, 2022, Xcel Energy had no unsettled interest rate derivatives.

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 is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

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.

Xcel Energy may enter 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. The classification of gains or losses for these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms. As of June 30, 2022, Xcel Energy had no commodity contracts designated as cash flow hedges.

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.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [(a)(b)]	**June 30, 2022**	**Dec. 31, 2021**
Megawatt hours of electricity	106	80
Million British thermal units of natural gas	159	156

(a) Not reflective of net positions in the underlying commodities.

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

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of 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. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

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, 2022, five of Xcel Energy's ten most significant counterparties for these activities, comprising $71 million, or 27%, of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Three of the ten most significant counterparties, comprising $58 million, or 22%, of this credit exposure, were not rated by these external ratings agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. Two of these significant counterparties, comprising $74 million, or 28%, of this credit exposure, had credit quality less than investment grade, based on internal analysis. Seven of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activity —

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Three Months Ended June 30, 2022		
Derivatives designated as cash flow hedges:		
Interest rate	$ 15	$ —
Total	$ 15	$ —
Other derivative instruments:		
Electric commodity	$ —	$ 98
Natural gas commodity	—	(1)
Total	$ —	$ 97
Six Months Ended June 30, 2022		
Derivatives designated as cash flow hedges:		
Interest rate	$ 22	$ —
Total	$ 22	$ —
Other derivative instruments:		
Electric commodity	$ —	$ 100
Natural gas commodity	—	3
Total	$ —	$ 103
Three Months Ended June 30, 2021		
Other derivative instruments:		
Electric commodity	$ —	$ 11
Natural gas commodity	—	(1)
Total	$ —	$ 10
Six Months Ended June 30, 2021		
Other derivative instruments:		
Electric commodity	$ —	$ 13
Total	$ —	$ 13

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Three Months Ended June 30, 2022			
Derivatives designated as cash flow hedges:			
Interest rate	$ 1 [a]	$ —	$ —
Total	$ 1	$ —	$ —
Other derivative instruments:			
Commodity trading	$ —	$ —	$ 7 [b]
Electric commodity	—	(26) [c]	—
Total	$ —	$ (26)	$ 7
Six Months Ended June 30, 2022			
Derivatives designated as cash flow hedges:			
Interest rate	$ 3 [a]	$ —	$ —
Total	$ 3	$ —	$ —
Other derivative instruments:			
Commodity trading	$ —	$ —	$ 9 [b]
Electric commodity	—	(36) [c]	—
Natural gas commodity	—	4 [d]	(17) [d][e]
Total	$ —	$ (32)	$ (8)
Three Months Ended June 30, 2021			
Derivatives designated as cash flow hedges:			
Interest rate	$ 2 [a]	$ —	$ —
Total	$ 2	$ —	$ —
Other derivative instruments:			
Commodity trading	$ —	$ —	$ 12 [b]
Electric commodity	—	3 [c]	—
Total	$ —	$ 3	$ 12
Six Months Ended June 30, 2021			
Derivatives designated as cash flow hedges:			
Interest rate	$ 6 [a]	$ —	$ —
Total	$ 6	$ —	$ —
Other derivative instruments:			
Commodity trading	$ —	$ —	$ 48 [b]
Electric commodity	—	(23) [c]	—
Natural gas commodity	—	8 [d]	(10) [d][e]
Total	$ —	$ (15)	$ 38

(a) Recorded to interest charges.
(b) 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) 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. All FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.
(d) Recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.
(e) Relates primarily to option premium amortization.

Xcel Energy had no derivative instruments designated as fair value hedges during the six months ended June 30, 2022 and 2021.

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 consolidated balance sheets, 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. At June 30, 2022 and Dec. 31, 2021, there were $11 million and $3 million, respectively, of derivative liabilities with such underlying contract provisions. Certain contracts also contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of June 30, 2022 and Dec. 31, 2021, there were approximately $117 million and $64 million, respectively, of derivative liabilities 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, 2022 and Dec. 31, 2021**.**

Recurring Fair Value Measurements — Derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	June 30, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting [a]**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting [a]**	**Total**
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 57	$ 233	$ 60	$ 350	$ (255)	$ 95	$ 22	$ 137	$ 21	$ 180	$ (134)	$ 46
Electric commodity [b]	—	—	428	428	(3)	425	—	—	57	57	(1)	56
Natural gas commodity	—	9	—	9	—	9	—	18	—	18	—	18
Total current derivative assets	$ 57	$ 242	$ 488	$ 787	$ (258)	529	$ 22	$ 155	$ 78	$ 255	$ (135)	120
PPAs [c]						5						3
Current derivative instruments						$ 534						$ 123
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 48	$ 121	$ 94	$ 263	$ (163)	$ 100	$ 16	$ 63	$ 89	$ 168	$ (107)	$ 61
Total noncurrent derivative assets	$ 48	$ 121	$ 94	$ 263	$ (163)	100	$ 16	$ 63	$ 89	$ 168	$ (107)	61
PPAs [c]						5						6
Noncurrent derivative instruments						$ 105						$ 67

	June 30, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting [a]**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting [a]**	**Total**
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 46	$ 279	$ 21	$ 346	$ (229)	$ 117	$ 19	$ 148	$ 20	$ 187	$ (143)	$ 44
Electric commodity	—	—	3	3	(3)	—	—	—	1	1	(1)	—
Natural gas commodity	—	8	—	8	—	8	—	8	—	8	—	8
Total current derivative liabilities	$ 46	$ 287	$ 24	$ 357	$ (232)	125	$ 19	$ 156	$ 21	$ 196	$ (144)	52
PPAs [c]						17						17
Current derivative instruments						$ 142						$ 69
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 56	$ 145	$ 73	$ 274	$ (191)	$ 83	$ 18	$ 48	$ 127	$ 193	$ (128)	$ 65
Total noncurrent derivative liabilities	$ 56	$ 145	$ 73	$ 274	$ (191)	83	$ 18	$ 48	$ 127	$ 193	$ (128)	65
PPAs [c]						37						40
Noncurrent derivative instruments						$ 120						$ 105

(a) Xcel Energy nets derivative instruments and related collateral on its consolidated balance sheets 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, 2022 and Dec. 31, 2021. At both June 30, 2022 and Dec. 31, 2021, derivative assets and liabilities include no obligations to return cash collateral. At June 30, 2022 and Dec. 31, 2021, derivative assets and liabilities include rights to reclaim cash collateral of $2 million and $30 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) Amounts relate to FTR instruments administered by MISO and SPP (annual auctions occurring in the second quarter). These instruments are utilized/intended to offset the impacts of transmission system congestion. Higher congestion costs have led to an increase in the fair value of FTRs. Due to regulatory recovery, changes in fair value are deferred as a regulatory asset or liability and do not have a material impact on net income.

(c) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, 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.

Changes in Level 3 commodity derivatives:

(Millions of Dollars)	Three Months Ended June 30 2022	2021
Balance at April 1	$ 39	$ (13)
Purchases / Issuances [(a)]	390	63
Settlements [(a)]	(155)	(32)
Net transactions recorded during the period:		
Gains recognized in earnings [(b)]	78	9
Net gains recognized as regulatory assets and liabilities [(a)]	133	44
Balance at June 30	$ 485	$ 71

(Millions of Dollars)	Six Months Ended June 30 2022	2021
Balance at Jan. 1	$ 19	$ (49)
Purchases / Issuances [(a)]	394	63
Settlements [(a)]	(181)	(48)
Net transactions recorded during the period:		
Gains recognized in earnings [(b)]	120	47
Net gains recognized as regulatory assets and liabilities [(a)]	133	58
Balance at June 30	$ 485	$ 71

(a) Relates primarily to FTR instruments administered by MISO and SPP (annual auctions occurring in the second quarter). These instruments are utilized/intended to offset the impacts of transmission system congestion. Higher congestion costs have led to an increase in the fair value of FTRs. Due to regulatory recovery, changes in fair value are deferred as a regulatory asset or liability and do not have a material impact on net income.

(b) Relates to commodity trading and is subject to offsetting losses of derivative instruments categorized as levels 1 and 2 in the consolidated income statement.

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 six months ended June 30, 2022 and 2021.

Fair Value of Long-Term Debt

Other financial instruments for which the carrying amount did not equal fair value:

	June 30, 2022		Dec. 31, 2021	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 23,856	$ 22,076	$ 22,380	$ 25,232

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. Fair value estimates are based on information available to management as of June 30, 2022 and Dec. 31, 2021 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

9. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2022	2021	2022	2021
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 25	$ 26	$ 1	$ 1
Interest cost [(a)]	28	26	4	3
Expected return on plan assets [(a)]	(52)	(51)	(5)	(5)
Amortization of prior service credit [(a)]	(1)	(1)	(1)	(2)
Amortization of net loss [(a)]	18	27	—	2
Net periodic benefit cost (credit)	18	27	(1)	(1)
Effects of regulation	1	—	—	—
Net benefit cost (credit) recognized for financial reporting	$ 19	$ 27	$ (1)	$ (1)

	Six Months Ended June 30			
	2022	2021	2022	2021
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 49	$ 52	$ 1	$ 1
Interest cost [(a)]	55	52	8	7
Expected return on plan assets [(a)]	(104)	(103)	(9)	(9)
Amortization of prior service credit [(a)]	(1)	(1)	(3)	(4)
Amortization of net loss [(a)]	37	54	1	3
Settlement charge [(b)]	(1)	—	—	—
Net periodic benefit cost (credit)	35	54	(2)	(2)
Effects of regulation	6	(1)	1	1
Net benefit cost (credit) recognized for financial reporting	$ 41	$ 53	$ (1)	$ (1)

(a) The components of net periodic cost other than the service cost component are included in the line item "Other income, net" in the consolidated statements of income or capitalized on the consolidated balance sheets as a regulatory asset.

(b) In the six months ended June 30, 2022, Xcel Energy recognized $1 million in settlement charge true-ups related to the fourth quarter 2021.

In January 2022, contributions of $50 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2022.

10. Commitments and Contingencies

The following includes commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

Legal

Xcel Energy is involved in various litigation matters 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 losses 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, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's consolidated financial statements. Legal fees are generally expensed as incurred.

Gas Trading Litigation — 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. Multiple lawsuits involving multiple plaintiffs seeking monetary damages were commenced against e prime and its affiliates, including Xcel Energy, between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Cases were all consolidated in the U.S. District Court in Nevada.

One case remains active which includes a multi-district litigation matter consisting of a Wisconsin purported class (Arandell Corp.). The Court issued a ruling on June 30, 2022 granting plaintiffs' class certification. Defendants will work together to prepare and file a petition appealing the class certification ruling to the Seventh Circuit. Xcel Energy has concluded that a loss is remote for the remaining lawsuit.

Comanche Unit 3 Litigation — In September 2021, CORE filed a lawsuit in Denver County District Court. CORE alleges PSCo breached ownership agreement terms by failing to operate Comanche Unit 3 in accordance with prudent utility practices. In January 2022, the Court granted PSCo's motion and dismissed CORE's claims for unjust enrichment, declaratory judgment and damages for replacement power costs. In February 2022, CORE disclosed that it is claiming in excess of $125 million in total damages.

In April 2022, CORE filed a supplement to include the January 2022 outage. It claims additional undisclosed damages arising from this event.

Rate Matters and Other

Xcel Energy's operating subsidiaries are involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the consolidated financial statements.

Minnesota Winter Storm Uri Costs — NSP-Minnesota is participating in a contested case regarding the prudency of incremental natural gas costs incurred during Winter Storm Uri. Other parties to the case have recommended significant cost disallowances, and while ultimate resolution of the matter is uncertain, it is reasonably possible that the MPUC could disallow certain deferred costs, resulting in earnings losses.

NSP-Minnesota filed rebuttal testimony in January 2022 detailing its position that the disallowances recommended by other parties lack any merit in the prudency review given the pertinent facts regarding NSP-Minnesota's actions before, during and after the storm event.

In March 2022, following February 2022 ALJ hearings, the OAG recommended a disallowance of up to $148 million, the largest recommendation among the intervenor positions. In May 2022, the ALJs found that the natural gas costs for Winter Storm Uri were prudently incurred and recommended no disallowances. A MPUC decision is expected in August 2022.

Sherco — In 2018, NSP-Minnesota and SMMPA (Co-owner of Sherco Unit 3) reached a settlement with GE related to a 2011 incident, which damaged the turbine at Sherco Unit 3 and resulted in an extended outage for repair. NSP-Minnesota notified the MPUC of its proposal to refund settlement proceeds to customers through the fuel clause adjustment.

In March 2019, the MPUC approved NSP-Minnesota's settlement refund proposal. Additionally, the MPUC decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of an appeal pending between GE and NSP-Minnesota's insurers. In February 2020, the Minnesota Court of Appeals affirmed the district court's judgment in favor of GE. In March 2020, NSP-Minnesota's insurers filed a petition seeking additional review by the Minnesota Supreme Court. In April 2020, the Minnesota Supreme Court denied the insurers' petition for further review, ending the litigation.

In January 2021, the OAG and DOC recommended that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the fuel clause adjustment. NSP-Minnesota subsequently filed its response, asserting that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed $22 million of related costs and no additional refund or disallowance is appropriate.

In July 2022, the MPUC referred the matter to the Office of Administrative Hearings to conduct a contested case on the prudence of the replacement power costs incurred by NSP-Minnesota. A final decision by the MPUC is expected in mid-2023. A loss related to this matter is deemed remote.

Westmoreland Arbitration — In November 2014, insurers of the Westmoreland Coal Company filed an arbitration demand against NSP-Minnesota, SMMPA and Western Fuels Association, seeking recovery of alleged business losses due to a turbine failure at Sherco Unit 3, which currently include $19 million in damages, plus prejudgment interest. The Westmoreland insurers claim NSP-Minnesota's invocation of the force majeure clause to stop the supply of coal was improper because the incident was allegedly caused by NSP-Minnesota's failure to conform to industry maintenance standards.

NSP-Minnesota denies the claims asserted by the Westmoreland insurers and believes it properly stopped the supply of coal based upon the force majeure provision. In the second quarter of 2022, this matter settled for $2 million.

MISO ROE Complaints — In November 2013 and February 2015, customer groups filed two ROE complaints against MISO TOs, which includes NSP-Minnesota and NSP-Wisconsin. The first complaint requested a reduction in base ROE transmission formula rates from 12.38% to 9.15% for the time period of Nov. 12, 2013 to Feb. 11, 2015, and removal of ROE adders (including those for RTO membership). The second complaint requested, for a subsequent time period, a base ROE reduction from 12.38% to 8.67%.

The FERC has subsequently issued various related orders (including Opinion Nos. 569, 569A and 569B) related to ROE methodology/calculations and timing. NSP-Minnesota has recognized a liability for its best estimate of final refunds to customers for applicable complaint periods.

The MISO TOs and various other parties have filed petitions for review of the FERC's most recent applicable opinions at the D.C. Circuit. A decision is expected by the end of the third quarter of 2022.

SPP OATT Upgrade Costs — Costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade under the SPP OATT. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover these previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C. Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. In February 2022, FERC issued an order rejecting SPS' request for hearing. SPS has appealed that order. That appeal has been combined with SPS' prior appeal.

Contract Termination — SPS and LP&L have a 25-year, 170 MW partial requirements contract. In May 2021, SPS and LP&L finalized a settlement which would terminate the contract upon LP&L's move from the SPP to the Electric Reliability Council of Texas (expected in 2023). The settlement agreement requires LP&L to pay SPS $78 million, to the benefit of SPS' remaining customers. LP&L would remain obligated to pay for SPP transmission charges associated with LP&L's load in SPP. The agreement is subject to approval by the PUCT and FERC.

Environmental

MGP, Landfill and Disposal Sites

Xcel Energy is investigating, remediating or performing post-closure actions at 14 MGP, landfill or other disposal sites across its service territories, excluding sites that are being addressed under current coal ash regulations (see below).

Xcel Energy has recognized its best estimate of costs/liabilities from final resolution of these issues, however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state regulations that impose requirements for handling, storage, treatment and disposal of solid waste. Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Currently, Xcel Energy has eight regulated ash units in operation.

In August 2020, the EPA published its final rule to implement closure by April 2021 for CCR impoundments. This final rule required Xcel Energy to expedite closure plans for two impoundments.

PSCo built an alternative collection and treatment system to remove a bottom ash pond from service. The total cost of the treatment system is approximately $25 million. PSCo removed the pond from service in June 2021 and did not meet the April 2021 deadline. PSCo has negotiated a compliance order with the EPA addressing the closure deadline, which includes a penalty of less than $1 million paid by PSCo.

The EPA recently clarified its interpretation/guidance regarding CCR units with ash in place and contact with groundwater. This guidance affects two of PSCo's facilities. PSCo is exploring an agreement with a company that would excavate and process the ash for beneficial use at a cost to PSCo of approximately $30 - $40 million. An estimated liability has been recorded within that range. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

In addition, increased concentrations of certain chemicals were detected in groundwater at or near four PSCo locations. PSCo is evaluating options for corrective action at two locations. The total cost is uncertain, but could be up to $35 million. PSCo is continuing to assess the financial and regulatory impacts.

Federal Clean Water Act Section 316(b) — The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates capital expenditures of approximately $40 million to comply with impingement and entrainment requirements. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required to make improvements to reduce impingement and entrainment. Xcel Energy anticipates these costs will be recoverable through regulatory mechanisms.

Environmental Requirements — Air

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes sulfur dioxide emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether sulfur dioxide emission reductions beyond those required in the BART alternative rule referenced above are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule, but could impose additional requirements as part of a BART reconsideration or as part of the second planning period.

Leases

Xcel Energy evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset.

Components of lease expense:

(Millions of Dollars)	Three Months Ended June 30 2022	2021
Operating leases		
PPA capacity payments	$ 60	$ 56
Other operating leases [(a)]	9	9
Total operating lease expense [(b)]	$ 69	$ 65
Finance leases		
Amortization of ROU assets	$ 1	$ 2
Interest expense on lease liability	4	4
Total finance lease expense	$ 5	$ 6

(a) Includes short-term lease expense of $2 million for 2022 and 2021.
(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

(Millions of Dollars)	Six Months Ended June 30 2022	2021
Operating leases		
PPA capacity payments	$ 123	$ 114
Other operating leases [(a)]	20	17
Total operating lease expense [(b)]	$ 143	$ 131
Finance leases		
Amortization of ROU assets	$ 2	$ 4
Interest expense on lease liability	8	8
Total finance lease expense	$ 10	$ 12

(a) Includes short-term lease expense of $3 million for 2022 and 2021.
(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating and finance leases as of June 30, 2022:

(Millions of Dollars)	PPA Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [(a)]
Total minimum obligation	$ 1,303	$ 171	$ 1,474	$ 236
Interest component of obligation	(186)	(31)	(217)	(165)
Present value of minimum obligation	$ 1,117	140	1,257	71
Less current portion			(210)	(4)
Noncurrent operating and finance lease liabilities			$ 1,047	$ 67

(a) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

Variable Interest Entities

Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse 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 IPP.

The utility subsidiaries had approximately 4,037 MW and 4,062 MW of capacity under long-term PPAs at June 30, 2022 and Dec. 31, 2021, respectively, with entities that have been determined to be variable interest entities. Xcel Energy concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

Other

Guarantees and Bond Indemnifications — Xcel Energy provides guarantees and bond indemnities, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability under the agreements. Most of the guarantees and bond indemnities issued by Xcel Energy have a stated maximum amount.

As of June 30, 2022 and Dec. 31, 2021, Xcel Energy had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements. Guarantees and bond indemnities issued and outstanding for Xcel Energy were approximately $61 million and $60 million at June 30, 2022 and Dec. 31, 2021, respectively.

Other Indemnification Agreements — Xcel Energy provides 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's obligations under these agreements may be limited in duration and amount. Maximum future payments under these indemnifications cannot be reasonably estimated.

11. Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive loss, net of tax, for the three and six months ended June 30, 2022 and 2021:

(Millions of Dollars)	Three Months Ended June 30, 2022: Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total	Three Months Ended June 30, 2021: Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at April 1	$ (69)	$ (47)	$ (116)	$ (82)	$ (56)	$ (138)
Other comprehensive gain before reclassifications	11	—	11	—	—	—
Losses reclassified from net accumulated other comprehensive loss:						
Interest rate derivatives [(a)]	1	—	1	2	—	2
Amortization of net actuarial loss [(b)]	—	1	1	—	1	1
Net current period other comprehensive income	12	1	13	2	1	3
Accumulated other comprehensive loss at June 30	$ (57)	$ (46)	$ (103)	$ (80)	$ (55)	$ (135)

(Millions of Dollars)	Six Months Ended June 30, 2022 Gains and Losses on Cash Flow Hedges	Six Months Ended June 30, 2022 Defined Benefit Pension and Postretirement Items	Six Months Ended June 30, 2022 Total	Six Months Ended June 30, 2021 Gains and Losses on Cash Flow Hedges	Six Months Ended June 30, 2021 Defined Benefit Pension and Postretirement Items	Six Months Ended June 30, 2021 Total
Accumulated other comprehensive loss at Jan. 1	$ (75)	$ (48)	$ (123)	$ (85)	$ (56)	$ (141)
Other comprehensive gain before reclassifications	16	—	16	—	—	—
Losses reclassified from net accumulated other comprehensive loss:						
Interest rate derivatives [a]	2	—	2	5	—	5
Amortization of net actuarial loss [b]	—	2	2	—	1	1
Net current period other comprehensive income	18	2	20	5	1	6
Accumulated other comprehensive loss at June 30	$ (57)	$ (46)	$ (103)	$ (80)	$ (55)	$ (135)

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs.

12. Segment Information

Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided including 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.

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** — The regulated electric utility segment generates, transmits and distributes electricity in 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. The regulated electric utility segment also includes wholesale commodity and trading operations.
- **Regulated Natural Gas** — The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Xcel Energy also presents All Other, which includes operating segments with revenues below the necessary quantitative thresholds. Those operating segments primarily include steam revenue, appliance repair services, non-utility 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 method investments of $220 million and $208 million as of June 30, 2022 and Dec. 31, 2021, respectively, included in the natural gas utility and all other segments.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments. As an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment. 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.

Certain costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators across each segment. In addition, a general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

Xcel Energy's segment information:

(Millions of Dollars)	Three Months Ended June 30 2022	Three Months Ended June 30 2021
Regulated Electric		
Operating revenues	$ 2,923	$ 2,597
Intersegment revenue	—	1
Total revenues	$ 2,923	$ 2,598
Net income	337	304
Regulated Natural Gas		
Operating revenues	$ 476	$ 449
Intersegment revenue	1	—
Total revenues	$ 477	$ 449
Net income	25	33
All Other		
Total revenues	$ 25	$ 22
Net loss	(34)	(26)
Consolidated Total		
Total revenues	$ 3,425	$ 3,069
Reconciling eliminations	(1)	(1)
Total operating revenues	$ 3,424	$ 3,068
Net income	328	311

(Millions of Dollars)	Six Months Ended June 30 2022	Six Months Ended June 30 2021
Regulated Electric		
Operating revenues	$ 5,556	$ 5,467
Intersegment revenue	—	1
Total revenues	$ 5,556	$ 5,468
Net income	615	573
Regulated Natural Gas		
Operating revenues	$ 1,566	$ 1,096
Intersegment revenue	1	1
Total revenues	$ 1,567	$ 1,097
Net income	155	151
All Other		
Total operating revenue	$ 53	$ 46
Net loss	(62)	(51)
Consolidated Total		
Total revenues	$ 7,176	$ 6,611
Reconciling eliminations	(1)	(2)
Total operating revenues	$ 7,175	$ 6,609
Net income	708	673

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.

The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

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 ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that adjusts measures calculated and presented in accordance with GAAP. Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our 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.

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

GAAP 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.

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Ongoing diluted EPS for Xcel Energy is calculated by dividing net income or loss, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing diluted EPS for each subsidiary is calculated by dividing the net income or loss for such 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, 2022 and 2021, 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. 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.

Summarized diluted EPS for Xcel Energy:

	Three Months Ended June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	**2022**	**2021**	**2022**	**2021**
PSCo	$ 0.24	$ 0.25	$ 0.56	$ 0.56
NSP-Minnesota	0.22	0.21	0.45	0.45
SPS	0.17	0.13	0.27	0.23
NSP-Wisconsin	0.03	0.03	0.11	0.09
Earnings from equity method investments —WYCO	0.01	0.01	0.02	0.02
Regulated utility [(a)]	0.67	0.62	1.41	1.35
Xcel Energy Inc. and Other	(0.07)	(0.04)	(0.11)	(0.10)
Total [(a)]	$ 0.60	$ 0.58	$ 1.30	$ 1.25

(a) Amounts may not add due to rounding.

Summary of Earnings

Xcel Energy — Xcel Energy's GAAP second quarter diluted earnings were $0.60 per share in 2022 compared with $0.58 per share in 2021. The increase was driven by regulatory recovery of capital investment, partially offset by higher depreciation, interest expense and O&M expenses. Costs for natural gas sold and transported significantly increased in 2022 primarily due to market price fluctuations. However, fluctuations in electric and natural gas revenues associated with changes in fuel and purchased power and/or natural gas sold and transported generally do not significantly impact earnings (changes in costs are offset by the related variation in revenues).

PSCo — Earnings decreased $0.01 per share for the second quarter of 2022 and were flat year-to-date. Year-to-date earnings reflect a Winter Storm Uri cost disallowance (see Other section) and unrecovered incremental purchased power costs due to the Comanche Unit 3 outage (see Other section).

NSP-Minnesota — Earnings increased $0.01 per share for the second quarter of 2022 and were flat year-to-date, as regulatory recovery of capital investment was offset by increased depreciation and interest expense.

SPS — Earnings increased $0.04 per share for the second quarter of 2022 and year-to-date, primarily due to regulatory outcomes, strong sales growth and favorable weather.

NSP-Wisconsin — Earnings were flat for the second quarter of 2022 and increased $0.02 per share year-to-date. The year-to-date increase reflects the impact of regulatory rate outcomes, sales growth and favorable weather, partially offset by higher depreciation and O&M expenses.

Xcel Energy Inc. and Other — Primarily includes financing costs at the holding company and earnings from Energy Impact Partners funds equity method investments.

Changes in GAAP and Ongoing Diluted EPS

Components significantly contributing to changes in 2022 EPS compared to 2021:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
GAAP and ongoing diluted EPS — 2021	**$ 0.58**	**$ 1.25**
Components of change - 2022 vs. 2021		
Higher electric revenues, net of electric fuel and purchased power	0.26	0.34
Lower effective tax rate (ETR) [(a)]	0.06	0.10
(Lower) higher natural gas revenues, net of cost of natural gas sold and transported	(0.01)	0.04
Higher depreciation and amortization	(0.15)	(0.21)
Higher interest charges	(0.05)	(0.06)
Higher taxes (other than income taxes)	(0.03)	(0.04)
Higher O&M expenses	(0.02)	(0.04)
Lower other (expense) income	(0.01)	(0.02)
Other, net	(0.03)	(0.06)
GAAP and ongoing diluted EPS — 2022	**$ 0.60**	**$ 1.30**

(a) Includes PTCs and plant regulatory amounts, which are primarily offset as a reduction to electric revenues.

Statement of Income Analysis

The following 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, the amount of natural gas or electricity historically used per degree of temperature and excludes any incremental related operating expenses that could result due to storm activity or vegetation management requirements. As a result, weather deviations from normal levels can affect Xcel Energy's financial performance. However, decoupling mechanisms in Colorado and proposed sales true-up mechanisms in Minnesota predominately mitigate the positive and adverse impacts of weather for the electric utility.

Degree-day or 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. HDD is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. 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. Typically, sales are not impacted in the first or fourth quarter due to THI or CDD.

Normal weather conditions are defined as either the 10, 20 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. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates.

Percentage increase (decrease) in normal and actual HDD, CDD and THI:

	Three Months Ended June 30			Six Months Ended June 30		
	2022 vs. Normal	2021 vs. Normal	2022 vs. 2021	2022 vs. Normal	2021 vs. Normal	2022 vs. 2021
HDD	6.3 %	1.7 %	3.2 %	9.1 %	1.4 %	7.1 %
CDD	29.7	3.5	31.7	28.9	3.0	31.0
THI	21.3	88.9	(33.1)	21.0	88.4	(33.0)

Weather — Estimated impact of temperature variations on EPS compared with normal weather conditions:

	Three Months Ended June 30			Six Months Ended June 30		
	2022 vs. Normal	2021 vs. Normal	2022 vs. 2021	2022 vs. Normal	2021 vs. Normal	2022 vs. 2021
Retail electric	$ 0.028	$ 0.056	$ (0.028)	$ 0.049	$ 0.055	$ (0.006)
Decoupling and sales true-up	(0.013)	(0.044)	0.031	(0.023)	(0.041)	0.018
Electric total	$ 0.015	$ 0.012	$ 0.003	$ 0.026	$ 0.014	$ 0.012
Firm natural gas	0.003	0.002	0.001	0.019	0.005	0.014
Total	$ 0.018	$ 0.014	$ 0.004	$ 0.045	$ 0.019	$ 0.026

Sales — Sales growth (decline) for actual and weather-normalized sales in 2022 compared to 2021:

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(6.3)%	(5.9) %	6.5 %	(3.0) %	(4.2) %
Electric C&I	(1.1)	0.6	11.7	2.5	3.2
Total retail electric sales	(2.8)	(1.4)	10.8	0.9	1.2
Firm natural gas sales	(9.6)	27.3	N/A	22.5	2.2

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized					
Electric residential	(5.0)%	0.9 %	(1.6)%	1.3 %	(1.7) %
Electric C&I	(0.6)	2.4	10.8	3.7	3.9
Total retail electric sales	(2.1)	2.0	8.6	3.0	2.3
Firm natural gas sales	(6.0)	12.7	N/A	11.4	0.2

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(3.7)%	(0.6) %	3.2 %	2.0 %	(1.0) %
Electric C&I	0.8	3.5	11.0	3.6	4.7
Total retail electric sales	(0.8)	2.2	9.4	3.1	3.0
Firm natural gas sales	(3.6)	22.1	N/A	22.2	5.6

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized					
Electric residential	(3.2)%	0.7 %	(0.8)%	1.0 %	(1.0) %
Electric C&I	1.0	4.1	10.4	3.9	4.8
Total retail electric sales	(0.4)	3.0	8.2	3.0	3.1
Firm natural gas sales	(2.5)	6.9	N/A	8.3	1.2

Weather-normalized electric sales growth (decline) — year-to-date

- PSCo — Residential sales declined due to decreased use per customer, partially offset by a 1.1% increase in customers. The growth in C&I sales was due to a 1.1% increase in customers, primarily in the professional services and retail sectors.
- NSP-Minnesota — Residential sales growth reflects a 1.2% increase in customers, partially offset by decreased use per customer. The growth in C&I sales was primarily due to higher use per customer, particularly in the manufacturing, real estate and leasing, and food service sectors.
- SPS — Residential sales declined due to a lower use per customer, partially offset by a 1.0% increase in customers. C&I sales increased due to higher use per customer, primarily driven by the energy sector.
- NSP-Wisconsin — Residential sales growth was driven by a 0.7% increase in customers. C&I sales growth was primarily due to higher use per customer, primarily from increases in the manufacturing and transportation sectors.

Weather-normalized natural gas sales growth (decline) — year-to-date

- Natural gas sales reflect a higher customer use, primarily in NSP-Minnesota and NSP-Wisconsin, as well as a 1.2% increase in residential customers and a 0.5% increase in C&I customers.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium. However, these price fluctuations generally have minimal earnings impact due to fuel recovery mechanisms that recover fuel expenses. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes.

Electric revenues, fuel and purchased power and margin and explanation of the changes are listed as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2022	2021	2022	2021
Electric revenues	$ 2,923	$ 2,597	$ 5,556	$ 5,467
Electric fuel and purchased power	(1,181)	(1,047)	(2,275)	(2,433)
Electric margin	$ 1,742	$ 1,550	$ 3,281	$ 3,034

(Millions of Dollars)	Three Months Ended June 30, 2022 vs. 2021	Six Months Ended June 30, 2022 vs. 2021
Regulatory rate outcomes (Minnesota, Colorado, Texas, New Mexico and Wisconsin)	$ 124	$ 187
Revenue recognition for the Texas rate case surcharge [(a)]	85	85
Sales and demand [(b)]	38	60
Non-fuel riders	7	41
Conservation and demand side management (offset in expense)	9	22
Estimated impact of weather (net of decoupling/sales true-up)	2	9
PTCs flowed back to customers (offset by lower ETR)	(50)	(103)
Proprietary commodity trading, net of sharing [(c)]	(8)	(33)
Comanche Unit 3 outage unrecovered purchased power cost [(d)]	(8)	(18)
Other (net)	(7)	(3)
Total increase	$ 192	$ 247

(a) Recognition of revenue from the Texas rate case outcome is largely offset by recognition of previously deferred costs, see Public Utility Regulation for additional information.
(b) Sales excludes weather impact, net of decoupling in Colorado and proposed sales true-up mechanism in Minnesota.
(c) Includes $27 million of net gains recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri.
(d) See Other section for more information.

Natural Gas Margin

Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for the cost of natural gas sold are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Natural gas revenues, cost of natural gas sold and transported and margin and explanation of the changes are listed as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2022	2021	2022	2021
Natural gas revenues	$ 476	$ 449	$ 1,566	$ 1,096
Cost of natural gas sold and transported	(251)	(218)	(961)	(517)
Natural gas margin	$ 225	$ 231	$ 605	$ 579

(Millions of Dollars)	Three Months Ended June 30, 2022 vs. 2021	Six Months Ended June 30, 2022 vs. 2021
Regulatory rate outcomes (Minnesota, Wisconsin, North Dakota, Colorado)	$ (3)	$ 14
Estimated impact of weather	1	11
Other (net)	(4)	1
Total (decrease) increase	$ (6)	$ 26

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $14 million for the second quarter and $32 million year-to-date. O&M costs increased due to recognition of previously deferred amounts related to the Texas Electric Rate Case, additional investments in technology and customer programs and higher costs for storms and vegetation management. These increases were partially offset by a reduction in employee benefit costs and timing of certain power plant overhaul costs.

Depreciation and Amortization — Depreciation and amortization increased $110 million for the second quarter and $151 million year-to-date. The increase was primarily driven by several wind farms going into service, normal system expansion and recognition of previously deferred costs related to the Texas Electric Rate Case.

Other (Expense) Income — Other (expense) income decreased $9 million for the second quarter and $13 million year-to-date, largely related to rabbi trust performance, which is primarily offset in O&M expenses (employee benefit costs).

Interest Charges — Interest charges increased $35 million for the second quarter and $44 million year-to-date, largely due to increased long-term debt levels to fund capital investments and deferred balances related to Winter Storm Uri.

Income Taxes — Income tax benefit increased $36 million for the second quarter and $64 million year-to-date, primarily driven by an increase in wind PTCs due to greater production at existing wind farms and several new wind farms going into service. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

In April 2022, the Internal Revenue Service published inflation factors used to determine the PTC rate. As a result, the 2022 PTC rate on the sale of electricity produced from wind is 2.6 cents per kilowatt hour, compared to 2.5 cents for 2021.

Public Utility Regulation and Other

The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and West Gas Interstate. Xcel Energy is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota, South Dakota, Wisconsin, Michigan, Colorado, New Mexico and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. Our utility subsidiaries request changes in utility rates through commission filings. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and demand side management efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact Xcel Energy's results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2021 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings

2022 Minnesota Electric Rate Case — In October 2021, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested ROE of 10.2%, a 52.50% equity ratio and forward test years.

The request is detailed as follows:

(Amounts in Millions, Except Percentages)	2022	2023	2024	Total
Rate request	$ 396	$ 150	$ 131	$ 677
Increase percentage	12.2 %	4.8 %	4.2 %	21.2 %
Rate base	$ 10,931	$ 11,446	$ 11,918	N/A

In December 2021, the MPUC approved interim rates, subject to refund, of $247 million, effective Jan. 1, 2022. A current liability that represents NSP-Minnesota's best estimate of a refund obligation associated with interim rates was recorded as of June 30, 2022.

Next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: Oct. 3, 2022.
- Rebuttal testimony: Nov. 8, 2022.
- Hearing: Dec. 13-16, 2022.
- ALJ Report: March 31, 2023.
- MPUC Order: June 30, 2023.

2022 Minnesota Natural Gas Rate Case — In November 2021, NSP-Minnesota filed a request with the MPUC for an annual natural gas rate increase of $36 million, or 6.6%. The filing is based on a 2022 forecast test year and includes a requested ROE of 10.5%, an equity ratio of 52.5% and a rate base of $934 million.

In December 2021, the MPUC approved interim rates of $25 million, subject to refund, effective Jan. 1, 2022.

Next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: Aug. 30, 2022.
- Rebuttal testimony: Oct. 4, 2022.
- Hearing: Nov. 1-4, 2022.
- ALJ Report: Feb. 6, 2023.
- MPUC Order: April 26, 2023.

2021 North Dakota Natural Gas Rate Case — In September 2021, NSP-Minnesota filed a request with the NDPSC for a natural gas rate increase of $7 million, or 10.5%. The filing is based on a requested ROE of 10.5%, an equity ratio of 52.54%, a 2022 forecast test year and a rate base of $124 million. Interim rates of $7 million, subject to refund, were implemented on Nov. 1, 2021.

In May 2022, NSP-Minnesota and NDPSC Staff reached a natural gas settlement, which reflects a rate increase of $5 million, based on a 9.8% ROE and 52.54% equity ratio. A NDPSC decision is expected in the third quarter of 2022.

2022 South Dakota Electric Rate Case — On June 30, 2022, NSP-Minnesota filed a South Dakota electric rate case (first since 2014) seeking a revenue increase of approximately $44 million. The filing is based on a 2021 historic test year adjusted for certain known and measurable changes for 2022 and 2023, a requested ROE of 10.75%, rate base of approximately $947 million and an equity ratio of 53%. Final rates are expected to be effective in the first quarter of 2023.

Wind Repowering — In January 2021, the MPUC approved NSP-Minnesota's request for the repowering of 651 MW of owned wind projects. Two of the four repowering projects, where construction has not yet begun (in-service dates in 2025), now expect costs in excess of the original approval. Evaluation of options to mitigate the impact of these cost increases is on-going. An update to the MPUC is expected in the third or fourth quarter 2022.

Sherco Solar Proposal — In April 2021, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an initial estimated investment of approximately $575 million. NSP-Minnesota requested a delay in the procedural schedule due to recent solar supply chain disruptions and potential impact on pricing. An updated request was filed with the MPUC in July 2022 and a decision is now anticipated in the fourth quarter of 2022 or the first quarter of 2023. The proposed facilities are still expected to be in-service by the end of 2025.

Wind PPA Buyout — In July 2022, NSP-Minnesota requested approval from the MPUC for updated agreements with ALLETE Clean Energy to purchase the repowered 100 MW Northern Wind Facility and 22 MW Rock Aetna Facility. The MPUC previously approved NSP-Minnesota's acquisition of the projects, but the agreements required further approval due to updated terms of the acquisition, including an increase in the purchase price. The price increase is offset by higher expected PTC benefits, resulting in minimal change to the net cost to customers.

2022 RES Electric Rider — In November 2021, NSP-Minnesota filed the RES Rider. The requested amount of $264 million includes a true-up (2020 and 2021 riders) of $154 million and the 2022 requested amount of $110 million. A MPUC decision is pending.

2022 GUIC Natural Gas Rider — In October 2021, NSP-Minnesota filed the GUIC Rider for an amount of $27 million. A MPUC decision is pending.

2021 GUIC Natural Gas Rider — In October 2020, NSP-Minnesota filed the GUIC Rider for an amount of $27 million. A MPUC decision is pending.

2022 TCR Electric Rider — In November 2021, NSP-Minnesota filed the TCR Rider for an amount of $105 million. A MPUC decision is pending.

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See Note 12 to the consolidated financial statements of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2021 for further information. The circumstances set forth in Nuclear Power Operations included in Item 7 of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2021, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated by reference.

NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings

Michigan Natural Gas Rate Case —In July 2022, NSP-Wisconsin filed an application with the Public Service Commission of Michigan seeking a revenue increase in base natural gas rates of $1 million for the period of 2023-2025.

PSCo

Pending and Recently Concluded Regulatory Proceedings

Colorado Natural Gas Rate Case — In January 2022, PSCo filed a request with the CPUC seeking a net increase to retail natural gas rates of $107 million. The total change to base rates is $215 million, which reflects the transfer of $108 million previously recovered from customers through the PSIA rider. The request is based on a 10.25% ROE, an equity ratio of 55.66% and a 2022 current test year with a projected rate base of $3.6 billion. PSCo has requested a proposed effective date of Nov. 1, 2022.

Additionally, PSCo's request includes step revenue increases of $40 million (effective Nov. 1, 2023) and $41 million (effective Nov. 1, 2024) related to continued capital investment.

On June 15, 2022, eight parties filed testimony, with the CPUC Staff and the UCA filing comprehensive testimony. The Staff and UCA both recommended a historic test year with average rate base and no step increases for 2023 and 2024.

Proposed modifications to PSCo's request:

2022 Rate Request (Millions of Dollars)	Staff	UCA
Filed base revenue request	$ 215	$ 215
Less: previously authorized costs (existing riders)	108	108
Filed net increase to revenue	107	107
Recommended adjustments:		
Test year adjustments	(33)	(41)
ROE	(42)	(42)
Weather normalization adjustment	—	(7)
Depreciation expense change	14	—
Other, net	(15)	(5)
Total recommended adjustments	(76)	(95)
Total proposed revenue change	$ 31	$ 12

Positions on PSCo's filed gas rate request:

Recommended Position	Staff	UCA
ROE	9.00 %	9.00 %
Equity	55.00 %	51.50 %
Test year	Historic	Historic

In July 2022, PSCo filed rebuttal testimony and updated its revenue request from $215 million to $202 million.

Next steps in the procedural schedule are expected to be as follows:

- Settlement deadline: Aug. 3, 2022.
- Evidentiary hearings: Aug. 17-23, 2022.
- Statement of position: Sept. 21, 2022.

Colorado Electric Rate Request — In July 2021, PSCo filed a request with the CPUC. In March 2022, the CPUC approved an unopposed settlement that included a net electric rate increase of $177 million, a ROE of 9.3% and an equity ratio of 55.69%. Rates became effective April 1, 2022.

Colorado Power Pathway Settlement — In June 2022, the CPUC issued a final written order issuing the CPCN for the Pathway Project. Key decisions include:

- The CPUC approved PSCo's cost estimate of $1.7 billion and recovery through the transmission rider.
- The CPUC modified the PIMs proposed in the settlement agreement, which focused on cost controls, to add a separate mechanism to further incentivize timely delivery of the Pathway Project segments. The CPUC also increased the magnitude of the PIMs.
- The CPUC granted conditional approval for the 345 kilovolt May Valley-Longhorn line extension, pending the level of renewables being added in that region through PSCo's resource plan. The initial cost estimate for the extension is approximately $250 million.

In July 2022, the CPUC modified the PIMs related to cost controls and project timing.

Colorado Resource Plan Settlement — In June 2022, the CPUC verbally approved a revised settlement, which will result in the further acceleration of the retirement of the Comanche Unit 3 coal plant, an expected carbon reduction of at least 85% and an 80% renewable mix by 2030. The CPUC deferred a decision on the method of cost recovery for the retiring coal units to a separate docket, which will consider accelerated depreciation, creation of regulatory assets and securitization. PSCo expects to file a recovery method docket in the fall.

Key settlement terms include:

- Early retirement of Hayden: Unit 2 in 2027 (was 2036); and Unit 1 in 2028 (was 2030).
- Conversion of the Pawnee coal plant to natural gas by no later than Jan. 1, 2026.
- Early retirement of Comanche Unit 3 by Jan. 1, 2031 (was 2070) with reduced operations beginning in 2025.
- Addition of ~2,400 MW of wind.
- Addition of ~1,600 MW of universal-scale solar.
- Addition of 400 MW of storage.
- Addition of 1,300 MW of flexible, dispatchable generation.
- Addition of ~1,200 MW of distributed solar resources through our renewable energy programs.

Colorado Partial Settlement — In October 2021, PSCo filed a comprehensive settlement with the CPUC Staff and the Colorado Energy Office, which proposed to address four outstanding regulatory items, including recovery of fuel costs related to Winter Storm Uri, disputed revenue associated with the 2020 electric decoupling pilot program year, replacement power costs associated with an extended outage at Comanche Unit 3 during 2020 and deferred customer bad debt balances associated with COVID-19. In July 2022, the CPUC approved the settlement, with an $8 million disallowance relating to the Winter Storm Uri fuel costs.

Key settlement terms include:

- PSCo will recover Winter Storm Uri deferred net natural gas, fuel and purchased energy costs (prior to the $8 million disallowance) of $263 million (electric utility) and $287 million (natural gas utility) over a 24-month and 30-month period, respectively, with no carrying charges through a rider mechanism.
- PSCo will refund electric customers $41 million (previously deferred) related to the 2020 electric decoupling pilot program.
- PSCo agreed to forego recovery of $14 million for replacement power costs due to an extended outage at Comanche Unit 3 during 2020 (approved by the CPUC in February 2022 as part of the 2020 retail electric commodity adjustment settlement agreement).
- PSCo also agreed to not seek recovery of COVID-19 related bad debt expense, previously deferred as a regulatory asset, and recorded an additional $11 million of incremental bad debt expense for the period ended Dec. 31, 2021.

Decoupling Filing — PSCo has a decoupling program, effective April 1, 2020 through Dec. 31, 2023. The program applies to Residential and metered small C&I customers who do not pay a demand charge. The program includes a refund and surcharge cap not to exceed 3% of forecasted base rate revenue for a specified period.

In October 2021, a settlement was reached on Winter Storm Uri costs and also addressed certain components of decoupling. See Colorado Partial Settlement disclosure above.

As of June 30, 2022, PSCo has recognized a refund for Residential customers and a surcharge for small C&I customers based on 2020, 2021 and the first and second quarters of 2022 results.

In April 2022, PSCo made its annual filing. In May 2022 the UCA filed a protest raising issues relating to the Winter Storm Uri settlement and the soft cap components of the decoupling program. On May 25, 2022 the CPUC found merit in UCA's protest, suspended PSCo's advice letter and referred the matter to the ALJ.

2019 Electric Rate Case Appeal — In August 2020, PSCo filed an appeal with the Denver District Court seeking a review of CPUC decisions on gains and losses on sales of assets and other items. In January 2022, the court issued its decision that the CPUC's approach to gains and losses on certain sales of assets was legally erroneous and confiscatory to PSCo and set aside and remanded the issue for further consideration. The CPUC is expected to deliberate in the third quarter of 2022.

GCA NOPR — In June 2021, the CPUC issued a NOPR addressing the recovery of costs through the GCA. The CPUC has reopened the GCA NOPR matter and proposed a 2 step process aimed at 1) considering near term process changes to the GCA used by various utilities and 2) a longer term process to evaluate potential performance incentive GCA structures to be filed by Nov. 1, 2022. In step 1, consensus proposed rule amendments to update the process and filing requirements for GCA and related filings have been submitted to the CPUC for consideration.

Natural Gas Planning NOPR — In October 2021, the CPUC issued a NOPR to implement recent state legislation requiring natural gas utilities to develop clean heat plans as a means to meet state greenhouse gas emission reduction targets, as well as updated demand-side management criteria. Additionally, the proposed rules included new comprehensive natural gas infrastructure planning requirements and related CPCN application procedures, changes in natural gas line extension policy, and details on emission accounting related to clean heat plans.

SPS

Pending and Recently Concluded Regulatory Proceedings

2021 Texas Electric Rate Case — In 2021, SPS filed an electric rate case with the PUCT and its municipalities seeking an increase in base rates of approximately $140 million. In May 2022, the PUCT approved a settlement between SPS and intervening parties, which reflects the following terms:

- Base rate increase of $89 million effective retroactively to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for AFUDC purposes only.
- Depreciation lives for Tolk accelerated to 2034 and Harrington coal assets accelerated to 2024.

In July 2022, SPS filed to surcharge the final under-recovered amount, estimated to be approximately $85 million, substantially offset by the recognition of previously deferred costs. The impact of the retroactive amounts is as follows:

(Millions of Dollars)	Six Months Ended June 30, 2022
Revenue surcharge accrual	$ 85
Depreciation and amortization	(43)
O&M expenses	(16)
Interest expense	(12)
Taxes other than income taxes	(10)
Fuel and purchased power	(2)

Other

Supply Chain

Xcel Energy's ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Manufacturing processes have experienced disruptions related to scarcity of certain raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, labor shortages and the impact of international conflicts/issues. Xcel Energy continues to monitor the availability of materials and has sought to mitigate impacts by seeking alternative suppliers as necessary.

Advanced Metering Infrastructure Implementation

Supply chain issues associated with semi-conductors have delayed the availability of advanced metering infrastructure electric meters. Impacts are currently being evaluated and the 2022 and 2023 deployment schedule could be impacted.

Solar Resources

In April 2022, the U.S. Department of Commerce initiated an anti-circumvention investigation that would subject CSPV solar panels and cells imported from Malaysia, Vietnam, Thailand, and Cambodia with potential incremental tariffs ranging from 50% to 250%. These countries account for more than 80% of CSPV panel imports.

Uncertainty of the investigation and the adverse impact on potential tariffs has resulted in the cancellation or delay of certain domestic solar projects.

The impacts on Xcel Energy are as follows:

- *NSP-Minnesota Sherco Solar Project* — In April 2021, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an initial estimated investment of approximately $575 million. NSP-Minnesota requested a delay in the procedural schedule due to recent solar supply chain disruptions and potential impact on pricing. An updated request was filed with the MPUC in July 2022 and a decision is now anticipated in the fourth quarter of 2022 or the first quarter of 2023. The proposed facilities are still expected to be in-service by the end of 2025.
- *NSP-Wisconsin* — In June 2021, the Public Service Commission of Wisconsin approved NSP-Wisconsin's Western Mustang solar project, a 74 MW facility that would be built by a developer for approximately $100 million. The project was originally scheduled to go into service in 2022. As a result of the disruption of the solar supply chain, the developer has indicated difficulty delivering the project at the contract price and scheduled in-service date. Negotiations on a potential solution are on-going.
- *PSCo PPAs* — PSCo has several solar PPAs expected to commence with solar generating assets scheduled to go into service in late 2022 and early 2023. Some developers have indicated difficulty delivering the projects at the contract price and at the scheduled in-service date. Negotiations on a potential solution are on-going. PSCo is developing contingency plans in the event that the solar generating assets are not completed in time to meet the capacity needs of the 2023 summer season.

Marshall Wildfire

In December 2021, a wildfire ignited in Boulder County, Colorado (the "Marshall Fire"), which burned over 6,000 acres and destroyed or damaged over 1,000 structures. Boulder County authorities are currently investigating the fire and have not yet determined a cause. There were no downed power lines in the ignition area, and nothing the Company has seen to this point indicates that our equipment or operations caused the fire.

In Colorado, the standard of review governing liability differs from the "inverse condemnation" or strict liability standard utilized in California. In Colorado, courts look to whether electric power companies have operated their system with a heightened duty of care consistent with the practical conduct of its business, and liability does not extend to occurrences that cannot be reasonably anticipated. In addition, PSCo has been operating under a commission approved wildfire mitigation plan and carries wildfire liability insurance.

In March 2022, a class action suit was filed in Boulder County pertaining to the Marshall Fire. In the remote event PSCo was found liable related to this litigation and were required to pay damages, such amounts could exceed our insurance coverage and have a material adverse effect on our financial condition, results of operations or cash flows. In June 2022, Plaintiffs served the class action lawsuit. In July 2022, PSCo filed a Motion to Dismiss.

Comanche Unit 3 Outage — In late January 2022, PSCo experienced an outage at the Comanche Unit 3 coal plant. The plant returned to service in June 2022. PSCo will not seek recovery of the approximately $18 million of incremental replacement power costs, subject to true-up, incurred during the outage.

Colorado Ballot Initiative — In April 2022, a proposed ballot initiative was filed in the state of Colorado, which if approved, would require at least 5% of all gas and electric rates to be paid from profits as determined by the CPUC. At the end of April 2022, the initiative was approved by the Colorado Title Board for petition. If the petitioners receive 125,000 voter signatures by August 8, 2022, this initiative will be added to the ballot for the Colorado general election in November.

MISO Capacity Credits — The NSP System offered 1,500 MW of excess capacity into the MISO planning resource auction for June 2022 through May 2023. Due to a projected overall capacity shortfall in the MISO region, the 1,500 MWs offered cleared the auction at maximum pricing and is expected to generate revenues of approximately $89 million in 2022 and approximately $64 million in 2023. During the second quarter of 2022, the NSP System received approximately $13 million of capacity credits. These amounts will primarily be used to mitigate customer rate increases or returned through earnings sharing or other mechanisms.

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, Xcel Energy incurred net natural gas, fuel and purchased energy costs of approximately $1 billion (largely deferred as regulatory assets).

Regulatory Overview — Xcel Energy has natural gas, fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, the utility subsidiaries have deferred February 2021 cost increases for future recovery and sought recovery of the cost increases over a period of up to 63 months to mitigate the impact to customer bills. Additionally, we did not request recovery of financing costs in order to further limit the impact to our customers. Xcel Energy currently has approval for recovery of Winter Storm Uri costs in Wisconsin, Michigan, North Dakota and New Mexico. There were no material costs for South Dakota.

A summary of the pending regulatory requests for Winter Storm Uri cost recovery in the other states is listed below.

Proceedings initiated:

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	In 2021, the MPUC allowed recovery of $179 million of costs (with no financing charge) starting in September 2021, with a potential true-up pending a prudency review. The C&I class ($82 million) will be recovered over 27 months and the residential class ($97 million) will be recovered over a 63-month recovery period. The Department of Commerce recommended a disallowance of $122 million, the Office of the Attorney General recommended disallowances of $110 million to $148 million and the CUB recommended a $69 million disallowance. In May 2022, the ALJs found the Winter Storm Uri fuel costs were prudently incurred and recommended no disallowances. A MPUC decision is expected in August 2022.
PSCo	Colorado	In May 2021, PSCo filed a request with the CPUC to recover $263 million in weather-related electric costs, $287 million in incremental natural gas costs and $4 million in incremental steam costs over 24 months with no financing charge. In October, a partial settlement was reached with the Staff and the Colorado Energy Office, allowing full recovery of the Winter Storm Uri costs over a 24-month (electric) and 30-month period (natural gas), with no carrying charges. In May 2022, an ALJ recommended full recovery of all costs with no cost disallowances. In July 2022, the CPUC approved the partial settlement, but included an $8 million disallowance.
SPS	Texas	In 2021, SPS filed to recover $88 million of Winter Storm Uri costs over 24 months, as part of the Texas fuel surcharge filing, with total under-recovered costs of $121 million. In April 2022, interim rates designed to recover $121 million over 30 months were implemented. The interim rate recovery does not address the prudence of costs nor the retention of approximately $10 million related to market sales during the event. These items will be reviewed through the triennial Fuel Reconciliation proceeding and are subject to a final PUCT decision. In July 2022, the intervenors filed recommendations in the Fuel Reconciliation proceeding. The Texas Industrial Energy Consumers and PUCT staff recommended disallowances of approximately $10 million (off-system sales margins). The Office of Public Utility Counsel recommended disallowances of approximately $15 million (off-system sales margins and adjustment to energy loss factors). The Alliance of Xcel Municipalities recommended disallowances of approximately $100 million (natural gas storage, contracted capability and off-system sales margins). A hearing is scheduled to begin in August and a recommendation from the ALJ is expected in the fourth quarter of 2022.

Environmental

Affordable Clean Energy

In July 2019, the EPA adopted the ACE rule, which requires states to develop plans by 2022 for greenhouse gas reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the ACE rule. That decision essentially held that EPA's previous economy-wide regulatory approach taken in the 2015 CPP was consistent with the Clean Air Act. If upheld, that decision would have allowed the EPA to proceed with alternate regulation of coal-fired power plants consistent with the CPP approach. However, the Court of Appeals decision was appealed to the U.S Supreme Court. In a June 30, 2022, ruling, the Supreme Court held that a CPP economy-wide approach is not consistent with the Clean Air Act. Thus, if EPA is to proceed with new rules, they must be consistent with this ruling and be more similar to the ACE rule "inside the fenceline" approach. If any new rules require additional investment, Xcel Energy believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

Derivatives, Risk Management and Market Risk

We 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, 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 we expect that the counterparties will perform under the contracts underlying its derivatives, the contracts expose us to some credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the nuclear decommissioning fund and pension fund and Xcel Energy's ability to earn a return on short-term investments.

Commodity Price Risk — We are exposed to commodity price risk in our 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 fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Our risk management policy allows us to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

Wholesale and Commodity Trading Risk — Xcel Energy conducts 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. Our risk management policy allows management to conduct these activities within guidelines and limitations as approved by our risk management committee.

Fair value of net commodity trading contracts as of June 30, 2022:

	Futures / Forwards Maturity				
(Millions of Dollars)	**Less Than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**Greater Than 5 Years**	**Total Fair Value**
NSP-Minnesota [(a)]	$ (4)	$ (12)	$ (5)	$ (3)	$ (24)
NSP- Minnesota [(b)]	3	5	(2)	(3)	3
PSCo [(a)]	14	9	2	1	26
PSCo [(b)]	(33)	(39)	—	1	(71)
	$ (20)	$ (37)	$ (5)	$ (4)	$ (66)

	Options Maturity				
(Millions of Dollars)	**Less Than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**Greater Than 5 Years**	**Total Fair Value**
NSP-Minnesota [(b)]	$ 3	$ —	$ —	$ 11	$ 14
PSCo [(b)]	20	24	—	—	44
	$ 23	$ 24	$ —	$ 11	$ 58

[(a)] Prices actively quoted or based on actively quoted prices.
[(b)] Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the six months ended June 30:

(Millions of Dollars)	**2022**	**2021**
Fair value of commodity trading net contracts outstanding at Jan. 1	$ (33)	$ (54)
Contracts realized or settled during the period	6	(37)
Commodity trading contract additions and changes during the period	19	56
Fair value of commodity trading net contracts outstanding at March 31	$ (8)	$ (35)

At June 30, 2022, a 10% increase in market prices for commodity trading contracts through the forward curve would increase pre-tax income from continuing operations by approximately $13 million, whereas a 10% decrease would decrease pre-tax income from continuing operations by approximately $13 million. At June 30, 2021, a 10% increase in market prices for commodity trading contracts would increase pre-tax income from continuing operations by approximately $19 million, whereas a 10% decrease would decrease pre-tax income from continuing operations by approximately $19 million. Market price movements can exceed 10% under abnormal circumstances.

The utility subsidiaries' commodity trading operations measure the outstanding risk exposure to price changes on contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as VaR. VaR expresses the potential change in fair value on the outstanding contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, excluding both non-derivative transactions and derivative transactions designated as normal purchase, normal sales, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	**Three Months Ended June 30**	**Average**	**High**	**Low**
2022	$ 1.8	$ 2.0	$ 3.3	$ 1.1
2021	1.7	1.2	1.9	0.7

Nuclear Fuel Supply — NSP-Minnesota has contracted for and has its 2022 and 2023 enriched nuclear material requirements in various stages of processing in Canada, Europe and the United States. We will continue to monitor the evolving situation in Ukraine and its global impacts and will take necessary actions to ensure a secure supply of enriched nuclear material. NSP-Minnesota is scheduled to take delivery of approximately 30% of its average enriched nuclear material requirements from Russia through 2030.

Interest Rate Risk — Xcel Energy is subject to interest rate risk. Our 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, 2022 and 2021, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pre-tax interest expense annually by approximately $2 million and $18 million, respectively.

See Note 8 to the consolidated financial statements for a discussion of Xcel Energy's interest rate derivatives.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. The fund is invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for the purpose of decommissioning NSP-Minnesota's nuclear generating plants.

Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting.

Changes in discount rates and expected return on plan assets impact the value of pension and postretirement plan assets and/or benefit costs.

Credit Risk — Xcel Energy is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy maintains credit policies intended to minimize overall credit risk and actively monitors these policies to reflect changes and scope of operations.

At June 30, 2022, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $86 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $73 million. At June 30, 2021, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $64 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $24 million.

Xcel Energy conducts credit reviews for all counterparties and employs credit risk control, such as letters of credit, parental guarantees, master netting agreements and termination provisions. 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 our credit risk.

FAIR VALUE MEASUREMENTS

Xcel Energy uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value.

The Company's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

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 monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. 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, 2022.

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 deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at June 30, 2022.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Operating Cash Flows

(Millions of Dollars)		Six Months Ended June 30
Cash provided by operating activities — 2021	$	489
Components of change — 2022 vs. 2021		
Higher net income		35
Non-cash transactions [(a)]		106
Changes in working capital [(b)]		256
Changes in net regulatory and other assets and liabilities		1,102
Cash provided by operating activities — 2022	$	1,988

(a) Non-cash transactions applicable to net income (e.g., depreciation and amortization, nuclear fuel amortization, changes in deferred income taxes, allowance for equity funds used during construction, etc.).

(b) Working capital includes accounts receivable, accrued unbilled revenues, inventories, accounts payable, other current assets and other current liabilities.

Net cash provided by operating activities increased $1,499 million for the six months ended June 30, 2022 compared with the prior year. The increase was primarily due to the net natural gas, fuel and purchased energy costs related to Winter Storm Uri in the first quarter of 2021.

Investing Cash Flows

(Millions of Dollars)		Six Months Ended June 30
Cash used in investing activities — 2021	$	(2,202)
Components of change — 2022 vs. 2021		
Increased capital expenditures		(73)
Other investing activities		220
Cash used in investing activities — 2022	$	(2,055)

Net cash used in investing activities decreased $147 million for the six months ended June 30, 2022 compared with the prior year. The increase in capital expenditures was largely due to timing and normal system expansion.

Financing Cash Flows

(Millions of Dollars)		Six Months Ended June 30
Cash provided by financing activities — 2021	$	2,122
Components of change — 2022 vs. 2021		
Higher net short-term debt repayments		(2,030)
Higher long-term debt issuances, net of repayments		44
Higher proceeds from issuance of common stock		140
Other financing activities		(40)
Cash provided by financing activities — 2022	$	236

Net cash provided by financing activities decreased $1,886 million for the six months ended June 30, 2022 compared with the prior year. The decrease was primarily related to the amount/timing of debt issuances and repayments associated with Winter Storm Uri.

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.

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 2022, contributions of $50 million were made across four of Xcel Energy's pension plans.
- In 2021, contributions of $131 million were made across four of Xcel Energy's pension plans.
- 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 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.

Revolving Credit Facilities — Xcel Energy Inc., NSP-Minnesota, PSCo and SPS each have the right to request an extension of the revolving credit facility for two additional one-year periods beyond the June 2024 termination date. 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.

As of July 25, 2022, 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	$ 73	$ 1,177	$ 5	$ 1,182
PSCo	700	196	504	2	506
NSP-Minnesota	500	11	489	2	491
SPS	500	2	498	5	503
NSP-Wisconsin	150	86	64	1	65
Total	$ 3,100	$ 368	$ 2,732	$ 15	$ 2,747

(a) Credit facilities expire in June 2024.
(b) Includes outstanding commercial paper and letters of credit.

Bilateral Credit Agreement

In April 2022, NSP-Minnesota's uncommitted $75 million bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of June 30, 2022, NSP-Minnesota had $43 million of outstanding letters of credit under the $75 million bilateral credit agreement.

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:

- $1.25 billion for Xcel Energy Inc.
- $700 million for PSCo.
- $500 million for NSP-Minnesota.
- $500 million for SPS.
- $150 million for NSP-Wisconsin.

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

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2022	Year Ended Dec. 31, 2021
Borrowing limit	$ 3,100	$ 3,100
Amount outstanding at period end	136	1,005
Average amount outstanding	554	1,399
Maximum amount outstanding	1,136	2,054
Weighted average interest rate, computed on a daily basis	1.05 %	0.57 %
Weighted average interest rate at period end	1.90	0.31

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 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. The money pool balances are eliminated in consolidation. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions.

2022 Planned Financing Activity — During 2022, Xcel Energy Inc. plans to issue approximately $75 to $80 million of equity through the DRIP and benefit programs. In addition, Xcel Energy Inc. may issue up to $800 million in equity from 2022-2026. In 2022, approximately $150 million of equity has been issued through an ATM program. Xcel Energy Inc. and its utility subsidiaries issued or plan to issue the following long-term debt:

Issuer	Security	Amount	Status	Tenor	Coupon
Xcel Energy	Unsecured Senior Notes	$ 700 million	Completed	10 Year	4.60%
PSCo	First Mortgage Bonds	300 million	Completed	10 Year	4.10%
PSCo	First Mortgage Bonds	400 million	Completed	30 Year	4.50%
SPS	First Mortgage Bonds	200 million	Completed	30 Year	5.15%
NSP-Minnesota	First Mortgage Bonds	500 million	Completed	30 Year	4.50%
NSP-Wisconsin	First Mortgage Bonds	100 million	Q3 (a)	30 Year	4.86%

(a) The NSP-Wisconsin private placement first mortgage bonds have been priced and the transaction is expected to close on Sept. 12, 2022.

Financing plans are subject to change, depending on legislative initiatives (e.g., federal tax law changes), capital expenditures, regulatory outcomes, 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 2022 Earnings Guidance — Xcel Energy's 2022 GAAP and ongoing earnings guidance is a range of $3.10 to $3.20 per share.[(a)]

Key assumptions as compared with 2021 levels unless noted:

- 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 increase ~2%.
- Weather-normalized retail firm natural gas sales are projected to increase ~1%.
- Capital rider revenue is projected to increase $0 million to $10 million (net of PTCs).
- O&M expenses are projected to increase approximately 2%.
- Depreciation expense is projected to increase approximately $300 million to $310 million. The change in assumption is primarily a result of new rates going into effect in Texas and will be offset by revenue with minimal impact on earnings.
- Property taxes are projected to increase approximately $35 million to $45 million.
- Interest expense (net of AFUDC - debt) is projected to increase $100 million to $110 million. The assumption change reflects higher interest rates and slightly larger debt issuances.
- AFUDC - equity is projected to be relatively flat.
- ETR is projected to be ~(6%) to (8%).

(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 EPS to corresponding GAAP 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% to 7% based off of a 2021 base of $2.96 per share, which represents the mid-point of the revised 2021 guidance range of $2.94 to $2.98 per share.
- Deliver annual dividend increases of 5% to 7%.
- Target a dividend payout ratio of 60% to 70%.
- Maintain senior secured debt credit ratings in the A range.

ITEM 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes to the market risk disclosure included in our Annual Report on Form 10-K for the year ended Dec. 31, 2021 under "Derivatives, Risk Management and Market Risk."

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 CEO and CFO, allowing timely decisions regarding required disclosure.

As of June 30, 2022, 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 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 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 losses 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, would have a material effect on Xcel Energy's consolidated financial statements. Legal fees are generally expensed as incurred.

See Note 10 to the consolidated financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

Xcel Energy'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, 2021, 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 Purchaser:

For the quarter ended June 30, 2022, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., dated May 17, 2012	Xcel Energy Inc. Form 8-K dated May 16, 2012	3.01
3.02*	Bylaws of Xcel Energy Inc. as Amended on April 3, 2020	Xcel Energy Inc Form 8-K dated April 3, 2020	3.01
4.01*	Supplemental Indenture No. 16, dated as of May 6, 2022, by and between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as trustee, creating $700,000,000 aggregate principal amount of 4.60% Senior Notes, Series due June 1, 2032	Xcel Energy Inc. Form 8-K dated May 6, 2022	4.01
4.02*	Supplemental Trust Indenture dated as of May 1, 2022 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $500,000,000 aggregate principal amount of 4.50% First Mortgage Bonds, Series due June 1, 2052	NSP-Minnesota Form 8-K dated May 9, 2022	4.01
4.03*	Supplemental Indenture dated as of May 1, 2022, between PSCo and U.S. Bank Trust Company, National Association, as successor Trustee, creating $300 million principal amount of 4.10% First Mortgage Bonds, Series No. 38 due 2032 and $400 million principal amount of 4.50% First Mortgage Bonds, Series No. 39 due 2052	PSCo Form 8-K dated May 17, 2022	4.01
4.04*	Supplemental Indenture No. 9 dated as of May 1, 2022 between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as trustee, creating $200 million principal amount of 5.15% First Mortgage Bonds, Series No. 9 due 2052	SPS Form 8-K dated May 31, 2022	4.02
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	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

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.

7/28/2022

By: /s/ BRIAN J. VAN ABEL
Brian J. Van Abel
Executive Vice President, Chief Financial Officer
(Duly Authorized Officer and Principal Financial Officer)