



July 29, 2021

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
SECOND QUARTER 2021 EARNINGS REPORT

- GAAP 2021 second quarter earnings per share were \$0.58 compared with \$0.54 in 2020.
- Xcel Energy reaffirms 2021 EPS earnings guidance of \$2.90 to \$3.00.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2021 second quarter GAAP and ongoing earnings of \$311 million, or \$0.58 per share, compared with \$287 million, or \$0.54 per share in the same period in 2020.

Earnings reflect higher electric and natural gas margins, which more than offset additional depreciation, operating and maintenance (O&M) expenses, interest charges and less allowance for funds used during construction (AFUDC).

“Xcel Energy had a strong second quarter, and we reaffirm our 2021 guidance range. We reached constructive rate case settlements in New Mexico, North Dakota and Wisconsin, and continue to make important strides toward our interim goal of 80% carbon-free electricity by 2030 and our ultimate goal of delivering 100% carbon-free electricity to our customers by 2050,” said Ben Fowke, chairman and CEO.

“We recently submitted an updated resource plan in Minnesota, which will allow us to reach our carbon reduction goals faster and at a lower cost to our customers. We also received commission approval on two renewable projects, including the largest solar facility in western Wisconsin and a 120-megawatt wind repowering project in Minnesota.”

At 9:00 a.m. CDT today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial in 5 to 10 minutes prior to the start and follow the operator’s instructions.

US Dial-In: (888) 204-4368
International Dial-In: (400) 120-9101
Conference ID: 9915304

The conference call also will be simultaneously broadcast and archived on Xcel Energy’s website at www.xcelenergy.com. To access the presentation, click on Investor Relations. If you are unable to participate in the live event, the call will be available for replay from 12:00 p.m. CDT on July 29 through 12:00 p.m. CDT on August 1.

Replay Numbers

US Dial-In: (888) 203-1112
International Dial-In: (719) 457-0820
Access Code: 9915304

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 the 2021 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, 2020 and subsequent filings with the Securities and Exchange Commission, 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; operational safety, including our nuclear generation facilities; 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; 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 and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries 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; and costs of potential regulatory penalties.

For more information, contact:

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For news media inquiries only, please call Xcel Energy Media Relations (612) 215-5300

Xcel Energy website address: www.xcelenergy.com

This information is not given in connection with any sale, offer for sale or offer to buy any security.

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	
	2021	2020	2021	2020
Operating revenues				
Electric	\$ 2,597	\$ 2,286	\$ 5,467	\$ 4,489
Natural gas	449	280	1,096	863
Other	22	20	46	45
Total operating revenues	3,068	2,586	6,609	5,397
Operating expenses				
Electric fuel and purchased power	1,047	833	2,433	1,630
Cost of natural gas sold and transported	218	86	517	371
Cost of sales — other	9	8	17	17
Operating and maintenance expenses	600	550	1,184	1,129
Conservation and demand side management expenses	71	68	144	142
Depreciation and amortization	528	473	1,049	936
Taxes (other than income taxes)	157	146	320	295
Total operating expenses	2,630	2,164	5,664	4,520
Operating income	438	422	945	877
Other income (expense), net	3	5	8	(7)
Earnings from equity method investments	20	6	34	17
Allowance for funds used during construction — equity	18	37	32	61
Interest charges and financing costs				
Interest charges — includes other financing costs of \$7, \$7, \$14 and \$14, respectively	212	208	417	407
Allowance for funds used during construction — debt	(6)	(12)	(11)	(22)
Total interest charges and financing costs	206	196	406	385
Income before income taxes	273	274	613	563
Income tax benefit	(38)	(13)	(60)	(19)
Net income	\$ 311	\$ 287	\$ 673	\$ 582
Weighted average common shares outstanding:				
Basic	539	527	539	526
Diluted	539	527	539	527
Earnings per average common share:				
Basic	\$ 0.58	\$ 0.54	\$ 1.25	\$ 1.10
Diluted	0.58	0.54	1.25	1.10

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Investor Relations Earnings Release (Unaudited)

Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as certain non-GAAP financial measures such as ongoing return on equity (ROE), electric margin, natural gas margin, 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.

Ongoing ROE

Ongoing ROE is calculated by dividing the net income or loss of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results.

Electric and Natural Gas Margins

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

Earnings Adjusted for Certain Items (Ongoing Earnings and 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, 2021 and 2020, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

Note 1. Earnings Per Share Summary

Xcel Energy's 2021 second quarter earnings were \$0.58 per share compared to \$0.54 per share in 2020, primarily reflecting higher electric and natural gas margins (driven by capital investment recovery, regulatory outcomes and weather-normalized sales growth as compared to 2020, which was more adversely impacted by COVID-19). These drivers were partially offset by higher depreciation, O&M expenses, interest charges and lower AFUDC.

Summarized diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30		Six Months Ended June 30	
	2021	2020	2021	2020
PSCo	\$ 0.25	\$ 0.21	\$ 0.56	\$ 0.45
NSP-Minnesota	0.21	0.22	0.45	0.43
SPS	0.13	0.14	0.23	0.22
NSP-Wisconsin	0.03	0.02	0.09	0.09
Earnings from equity method investments - WYCO	0.01	0.01	0.02	0.02
Regulated utility ^(a)	0.62	0.60	1.35	1.20
Xcel Energy Inc. and Other	(0.04)	(0.07)	(0.10)	(0.10)
Total ^(a)	\$ 0.58	\$ 0.54	\$ 1.25	\$ 1.10

^(a) Amounts may not add due to rounding.

PSCo — Earnings increased \$0.04 per share for the second quarter of 2021 and \$0.11 per share year-to-date. The increase in year-to-date earnings reflects higher natural gas and electric margins (primarily capital investment recovery and regulatory outcomes), partially offset by additional depreciation and other taxes (other than income taxes).

NSP-Minnesota — Earnings decreased \$0.01 per share for the second quarter of 2021 and increased \$0.02 per share year-to-date. The increase in year-to-date earnings reflects higher electric margin (primarily capital investment recovery), partially offset by increased depreciation and O&M expenses.

SPS — Earnings decreased \$0.01 per share for the second quarter of 2021 and increased \$0.01 per share year-to-date. The increase in year-to-date earnings reflects higher electric margin (capital investment recovery and regulatory outcomes), partially offset by increased depreciation and O&M expenses.

NSP-Wisconsin — Earnings increased \$0.01 per share for the second quarter of 2021 and were flat year-to-date.

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

Components significantly contributing to changes in 2021 EPS compared to 2020:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
GAAP and ongoing diluted EPS — 2020	\$ 0.54	\$ 1.10
Components of change - 2021 vs. 2020		
Higher electric margin	0.14	0.25
Higher natural gas margins	0.05	0.12
Lower Effective Tax Rate (ETR) ^(a)	0.06	0.12
Higher other income (expense), net	—	0.02
Higher depreciation and amortization	(0.08)	(0.16)
Higher O&M expenses	(0.07)	(0.08)
Lower AFUDC	(0.05)	(0.07)
Higher interest charges	(0.01)	(0.01)
Other, net	—	(0.04)
GAAP and ongoing diluted EPS — 2021	\$ 0.58	\$ 1.25

^(a) Includes production tax credits (PTCs) and plant regulatory amounts, which are primarily offset in electric margin.

Note 2. Regulated Utility Results

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, sales true-up and decoupling mechanisms in Minnesota and Colorado predominately mitigate the positive and adverse impacts of weather.

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.

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

	Three Months Ended June 30			Six Months Ended June 30		
	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020
Retail electric	\$ 0.056	\$ 0.028	\$ 0.028	\$ 0.055	\$ 0.017	\$ 0.038
Decoupling and sales true-up	(0.044)	(0.014)	(0.030)	(0.041)	(0.009)	(0.032)
Electric total	\$ 0.012	\$ 0.014	\$ (0.002)	\$ 0.014	\$ 0.008	\$ 0.006
Firm natural gas	0.002	0.001	0.001	0.005	(0.006)	0.011
Total	\$ 0.014	\$ 0.015	\$ (0.001)	\$ 0.019	\$ 0.002	\$ 0.017

Sales — Sales growth (decline) for actual and weather-normalized sales in 2021 compared to 2020:

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	— %	6.1 %	(5.6)%	2.7 %	1.9 %
Electric C&I	6.2	10.1	7.5	11.6	8.3
Total retail electric sales	3.9	8.7	5.2	8.9	6.3
Firm natural gas sales	18.8	(9.5)	N/A	(2.5)	8.3
Weather-Normalized					
Electric residential	0.7 %	(1.6)%	(1.3)%	(2.3)%	(0.7)%
Electric C&I	6.5	8.3	8.4	10.2	7.9
Total retail electric sales	4.4	5.0	6.8	6.5	5.3
Firm natural gas sales	12.7	(2.6)	N/A	6.8	7.6
Actual					
Electric residential	3.2 %	5.6 %	1.8 %	3.8 %	4.0 %
Electric C&I	0.4	1.3	—	4.5	0.9
Total retail electric sales	1.4	2.7	0.3	4.3	1.8
Firm natural gas sales	8.0	(1.9)	N/A	—	4.4
Weather-Normalized					
Electric residential	2.9 %	1.6 %	1.4 %	0.5 %	2.0 %
Electric C&I	0.4	0.4	0.2	3.8	0.6
Total retail electric sales	1.2	0.7	0.5	2.8	1.0
Firm natural gas sales	2.4	(1.6)	N/A	(0.6)	0.9

	Six Months Ended June 30 (2020 Leap Year Adjusted)				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-Normalized					
Electric residential	3.4 %	2.2 %	2.0 %	1.1 %	2.5 %
Electric C&I	1.0	1.0	0.8	4.4	1.2
Total retail electric sales	1.8	1.3	1.0	3.4	1.6
Firm natural gas sales	3.3	(0.7)	N/A	0.3	1.8

Weather-normalized and leap-year adjusted electric sales growth (decline) — year-to-date (excluding leap day)

Weather-adjusted sales results for each of our utility subsidiaries in 2021 reflect improving economies as the adverse effects of COVID-19 lessen. The recovery reflects increased sales in the C&I sector as businesses return to a more normal level. Residential sales remain elevated on a year-to-date basis as individuals working from home have just begun returning to the office.

- PSCo — Residential sales rose based on an increase in the number of customers combined with higher use per customer. The growth in large C&I sales was primarily led by the service, agriculture, food and energy sectors, partially offset by a decrease in the manufacturing sector.
- NSP-Minnesota — Residential sales growth reflects an increase in the number of customers combined with higher use per customer. The growth in C&I sales was due to customer growth and slightly higher use per customer, primarily in the manufacturing sector.
- SPS — Residential sales rose based on an increase in the number of customers combined with higher use per customer. C&I sales increased due to higher use per customer and growth attributable to the food sector, partially offset by losses within the energy sector.
- NSP-Wisconsin — Residential sales growth was attributable to customer additions and higher use per customer. The growth in C&I sales was primarily led by increases in the services, agriculture, food and energy sectors, partially offset by a decrease in the manufacturing sector.

Weather-normalized and leap-year adjusted natural gas sales growth (decline) — year-to-date (excluding leap day)

- Natural gas sales primarily reflect an increase in the number of customers combined with slightly higher customer use.

Electric Margin — 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 have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and margin. See Note 5 for discussion of Winter Storm Uri.

Electric revenues and margin:

(Millions of Dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2021	2020	2021	2020
Electric revenues	\$ 2,597	\$ 2,286	\$ 5,467	\$ 4,489
Electric fuel and purchased power	(1,047)	(833)	(2,433)	(1,630)
Electric margin	\$ 1,550	\$ 1,453	\$ 3,034	\$ 2,859

Changes in electric margin:

(Millions of Dollars)	Three Months Ended June 30, 2021 vs. 2020	Six Months Ended June 30, 2021 vs. 2020
Non-fuel riders	\$ 89	\$ 133
Regulatory rate outcomes (Texas, New Mexico, Colorado, Wisconsin and North Dakota)	34	78
Proprietary commodity trading, net of sharing - Winter Storm Uri (see Note 5)	—	27
Sales and demand ^(a)	24	10
Estimated impact of weather (net of decoupling/sales true-up)	(1)	5
Wholesale transmission revenue (net)	(8)	3
PTCs flowed back to customers (offset by lower ETR)	(42)	(79)
Other (net)	1	(2)
Total increase in electric margin	<u>\$ 97</u>	<u>\$ 175</u>

^(a) Sales excludes weather impact, net of decoupling/sales true-up, and demand is net of sales true-up.

Natural Gas Margin — Natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to cost recovery mechanisms. See Note 5 for discussion of Winter Storm Uri.

Natural gas revenues and margin:

(Millions of Dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2021	2020	2021	2020
Natural gas revenues	\$ 449	\$ 280	\$ 1,096	\$ 863
Cost of natural gas sold and transported	(218)	(86)	(517)	(371)
Natural gas margin	<u>\$ 231</u>	<u>\$ 194</u>	<u>\$ 579</u>	<u>\$ 492</u>

Changes in natural gas margin:

(Millions of Dollars)	Three Months Ended June 30, 2021 vs. 2020	Six Months Ended June 30, 2021 vs. 2020
Regulatory rate outcomes (Colorado)	\$ 31	\$ 71
Estimated impact of weather	1	8
Other (net)	5	8
Total increase in natural gas margin	<u>\$ 37</u>	<u>\$ 87</u>

O&M Expenses — O&M expenses increased \$50 million, or 9.1%, for the second quarter and \$55 million, or 4.9% year-to-date. Significant changes are summarized as follows:

(Millions of Dollars)	Three Months Ended June 30, 2021 vs. 2020	Six Months Ended June 30, 2021 vs. 2020
Wind	\$ 14	\$ 22
Information technology and security	13	17
Natural gas systems	6	9
Distribution	9	8
Other	8	(1)
Total increase in O&M expenses	<u>\$ 50</u>	<u>\$ 55</u>

The increase was primarily due to expenses associated with new wind farms, software infrastructure and security costs, natural gas damage prevention, and timing of distribution expenses, partially offset by continuous improvement initiatives. Quarterly timing impacts also occurred throughout 2020 due to cost control initiatives to mitigate the adverse impact of COVID-19 on sales.

Depreciation and Amortization — Depreciation and amortization increased \$55 million, or 11.6%, for the second quarter and \$113 million, or 12.1% year-to-date. The increase was primarily driven by several wind farms going into service, as well as normal system expansion. In addition, 2021 depreciation expense increased as a result of implementation of new depreciation rates in various states.

Other Income (Expense) — Other income (expense) decreased \$2 million for the second quarter and increased \$15 million year-to-date, which was largely related to rabbi trust performance primarily offset in O&M expenses (compensation).

AFUDC, Equity and Debt — AFUDC decreased \$25 million for the second quarter of 2021 and \$40 million year-to-date. The decrease was primarily driven by completion of various wind projects.

Interest Charges — Interest charges increased \$4 million, or 1.9%, for the second quarter and \$10 million, or 2.5% year-to-date. The increase was largely attributable to higher long-term debt levels to fund capital investments and a term loan to finance Winter Storm Uri fuel costs, partially offset by lower long-term and short-term interest rates.

Earnings from Equity Method Investments — Earnings from equity method investments increased \$14 million for the second quarter and \$17 million year-to-date. The increase was largely attributable to the performance of the EIP funds, which invest in energy technology companies.

Income Taxes — Effective income tax rate:

	Three Months Ended June 30			Six Months Ended June 30		
	2021	2020	2021 vs 2020	2021	2020	2021 vs 2020
Federal statutory rate	21.0 %	21.0 %	— %	21.0 %	21.0 %	— %
State tax (net of federal tax effect)	4.9	5.1	(0.2)	4.9	5.0	(0.1)
(Decrease) increase:						
Wind PTCs	(33.1)	(21.1)	(12.0)	(28.4)	(19.1)	(9.3)
Plant regulatory differences ^(a)	(6.6)	(7.1)	0.5	(6.3)	(7.8)	1.5
Other (net)	(0.1)	(2.6)	2.5	(1.0)	(2.5)	1.5
Effective income tax rate	<u>(13.9)%</u>	<u>(4.7)%</u>	<u>(9.2)%</u>	<u>(9.8)%</u>	<u>(3.4)%</u>	<u>(6.4)%</u>

^(a) 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 credits are offset by corresponding revenue reductions.

Income tax benefit increased \$25 million for the second quarter and \$41 million year-to-date. The increase was primarily driven by an increase in wind PTCs due to additional facilities 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. Impact of PTCs was partially offset by higher pretax earnings in 2021.

Note 3. Capital Structure, Liquidity, Financing and Credit Ratings

Xcel Energy's capital structure:

(Millions of Dollars)	June 30, 2021	Percentage of Total Capitalization	Dec. 31, 2020	Percentage of Total Capitalization
Current portion of long-term debt	\$ 21	— %	\$ 421	1 %
Short-term debt	1,745	5	584	2
Long-term debt	21,476	56	19,645	56
Total debt	23,242	61	20,650	59
Common equity	14,792	39	14,575	41
Total capitalization	<u>\$ 38,034</u>	<u>100 %</u>	<u>\$ 35,225</u>	<u>100 %</u>

Liquidity — As of July 26, 2021, 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	\$ 508	\$ 742	\$ —	\$ 742
PSCo	700	9	691	3	694
NSP-Minnesota	500	9	491	226	717
SPS	500	13	487	2	489
NSP-Wisconsin	150	—	150	2	152
Total	\$ 3,100	\$ 539	\$ 2,561	\$ 233	\$ 2,794
Term Loan ^(c)	1,200	1,200	—		

^(a) Expires June 2024.

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

^(c) Matures February 2022.

Term Loan Agreements — In February 2021, Xcel Energy Inc. entered into a \$1.2 billion 364-Day Term Loan Agreement in order to enhance liquidity due to the incremental fuel costs from Winter Storm Uri and potential regulatory lag in recovery. See Note 5 for further discussion.

Bilateral Credit Agreement — In April 2021, NSP-Minnesota extended an uncommitted bilateral credit agreement of \$75 million (which is limited in use to support letters of credit for one-year). NSP-Minnesota had \$75 million of outstanding letters of credits as of June 30, 2021.

Credit Ratings — Access to the capital markets at reasonable terms is partially dependent on credit ratings. The following ratings reflect the views of Moody's, S&P Global Ratings and Fitch. The highest credit rating for debt is Aaa/AAA and the lowest investment grade rating is Baa3/BBB-. The highest rating for commercial paper is P-1/A-1/F-1 and the lowest rating is P-3/A-3/F-3. A security rating is not a recommendation to buy, sell or hold securities. Ratings are subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries as of July 26, 2021:

Credit Type	Company	Moody's	S&P Global Ratings	Fitch
Senior Unsecured Debt	Xcel Energy Inc.	Baa1	BBB+	BBB+
Senior Secured Debt	NSP-Minnesota	Aa3	A	A+
	NSP-Wisconsin	Aa3	A	A+
	PSCo	A1	A	A+
	SPS	A3	A	A-
Commercial Paper	Xcel Energy Inc.	P-2	A-2	F2
	NSP-Minnesota	P-1	A-2	F2
	NSP-Wisconsin	P-1	A-2	F2
	PSCo	P-2	A-2	F2
	SPS	P-2	A-2	F2

2021 Financing Activity — During 2021, Xcel Energy plans to issue approximately \$75 to \$80 million of equity through the DRIP and benefit programs. Xcel Energy Inc. and its utility subsidiaries issued the following:

Issuer	Security	Amount	Status	Tenor	Coupon
PSCo	First Mortgage Bonds	\$ 750	Completed	10 Year	1.875 %
SPS	First Mortgage Bonds	250	Completed	29 Year	3.15
NSP-Minnesota	First Mortgage Bonds	425	Completed	10 Year	2.25
NSP-Minnesota	First Mortgage Bonds	425	Completed	31 Year	3.20
NSP-Wisconsin	First Mortgage Bonds	100	Q3 ^(a)	30 Year	2.82

^(a) The NSP-Wisconsin private placement first mortgage bond has been priced and is expected to close on July 30, 2021.

In addition, Xcel Energy may issue a holding company bond in the fourth quarter to pay down the outstanding term loan.

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

Note 4. Rates and Regulation

NSP-Minnesota — Minnesota Relief and Recovery

- In April 2021, NSP-Minnesota proposed to add 460 megawatts (MW) of solar facilities at the Sherco site with an incremental investment of approximately \$575 million. A Minnesota Public Utilities Commission (MPUC) decision is expected in late 2021 or 2022.
- In June 2021, the MPUC approved NSP-Minnesota's proposal to acquire a 120 MW repowered wind farm from ALLETE for \$210 million.

NSP-Minnesota — 2020 North Dakota Electric Rate Case — In November 2020, NSP-Minnesota filed a rate case with the North Dakota Public Service Commission (NDPSC). NSP-Minnesota requested an increase in annual retail electric revenues of approximately \$19 million. The rate filing was based on a 2021 forecast test year, a ROE of 10.2%, an equity ratio of 52.5% and an electric rate base of approximately \$677 million. Interim rates, subject to refund, of approximately \$13 million are currently in effect.

In July 2021, NSP-Minnesota and various parties filed an uncontested settlement agreement, which includes:

- Base revenue increase of \$7 million.
- ROE of 9.5%.
- Equity ratio of 52.5%.
- Deferral of advanced grid intelligence and security (AGIS) initiative capital and O&M expenses.
- An earnings cap mechanism, which would return to customers 100% of earnings equal to or in excess of 9.75% ROE, effective until the next rate case.

A NDPSC decision on the settlement and implementation is anticipated in the fourth quarter of 2021.

NSP-Minnesota — Minnesota Resource Plan — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034. The initial plan was expected to result in an 80% carbon reduction by 2030 (from 2005) and puts NSP-Minnesota on a path to achieving its vision of being 100% carbon-free by 2050. Parties submitted comments in February 2021 and there was significant opposition to the proposal to build a Sherco combined cycle natural gas plant and associated pipeline infrastructure.

In June 2021, NSP-Minnesota filed an alternative plan that would reduce carbon emissions 85% by 2030 and has a lower projected cost than either of the previously submitted plans. The alternative plan includes the following:

- Removing the planned Sherco combined cycle natural gas plant.
- Retiring all coal generation by 2030 with reduced operations at some units prior to retirement, including early retirement of the A.S. King coal plant (511 MW) in 2028 and Sherco 3 coal plant (517 MW) in 2030.
- Extending the life of the Monticello nuclear plant from 2030 to 2040.
- Continuing to run the Prairie Island nuclear generating plant at least through current end of life (2033 and 2034).
- Adding 3,150 MW of universal solar, 2,650 MW of wind and 250 MW of storage.
- Adding 800 MW of new hydrogen-ready combustion-turbines (CTs) and repowering 300 MW of blackstart CTs.
- Adding 1,900 MW of other firm dispatchable resources.
- Constructing 155 miles of transmission lines.
- Achieving 780 gigawatt hours in energy efficiency savings annually through 2034.
- Adding 400 MW of incremental demand response by 2023 and a total of 1,500 MW of demand response by 2034.

Supplemental comments are due Aug. 13, 2021. The MPUC is anticipated to make a final decision in late 2021 or early 2022.

NSP-Wisconsin — Solar Proposal — In June 2021, the Public Service Commission of Wisconsin (PSCW) approved NSP-Wisconsin's request to purchase the 74 MW Western Mustang build-own-transfer solar facility for approximately \$100 million. The project is scheduled to go into service in 2023.

NSP-Wisconsin — Wisconsin Electric and Natural Gas Settlement — In July 2021, NSP-Wisconsin filed an application with the PSCW seeking approval of a rate case settlement with various intervenors for 2022-2023. The settlement agreement increases electric rates by \$35 million (4.9%) for 2022 and an incremental \$18 million increase (2.5%) for 2023. For the natural gas utility, rates increase by \$10 million (8.4%) for 2022, and an incremental \$3.0 million (2.3%) increase for 2023.

Key elements of the settlement:

- ROE of 9.80% for 2022 and 10.00% for 2023.
- Equity ratio of 52.5% for both 2022 and 2023.
- Returning \$9 million in various net regulatory liabilities to offset customer impacts in 2023.
- Deferring certain pension and other post-employment benefit expense in 2021 through 2023.
- Addressing COVID-19 deferral recovery in the next rate case proceeding.
- Deferring potential changes in tax expenses due to changes in federal or state tax law in 2021 through 2023.
- Incorporating an earnings sharing mechanism for 2022 and 2023.

A PSCW decision is anticipated in the fourth quarter of 2021.

Colorado Electric Rate Request — In July 2021, PSCo filed a request with the Colorado Public Utilities Commission (CPUC) seeking a net increase to retail electric base rate revenue of \$343 million (or 12.4%). The total request reflects a \$470 million increase, which includes \$127 million of previously authorized costs currently recovered through various rider mechanisms. The request is based on a 10.0% ROE, an equity ratio of 55.64% and a 2022 forecast test year. The request also includes impacts of a new depreciation study. A historical test year, including a 10.5% ROE, was also filed as required by the CPUC. Rates are expected to be effective April 9, 2022.

Revenue Request (millions of dollars)	2022
Changes since 2019 rate case:	
Plant-related growth	\$ 95
AGIS	73
Updated cost of capital	53
New depreciation rates	43
Wildfire mitigation	25
Property taxes	25
Amortization of previously approved deferrals	17
Other	12
Net increase to revenue	343
Roll-in of previously authorized costs:	
TCA rider revenues and Cheyenne Ridge costs	127
Total base revenue request	\$ 470

Expected average 2022 rate base (billions of dollars)	\$ 10.3
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SPS — New Mexico 2021 Electric Rate Case — In January 2021, SPS filed an electric rate case with the New Mexico Public Regulation Commission (NMPRC) seeking an increase in base rates of approximately \$88 million. SPS' net rate increase to New Mexico customers is expected to be approximately \$48 million, or 10%, as a result of offsetting fuel cost reductions and PTCs from the Sagamore wind project. PTCs are credited to customers through the fuel clause. In June 2021, SPS revised its requested base rate increase to \$84 million.

The request was based on a historic test year ended Sept. 30, 2020, including expected capital additions through Feb. 28, 2021, a ROE of 10.35%, an equity ratio of 54.72% and a retail rate base of approximately \$1.9 billion.

In June 2021, SPS and various parties filed an uncontested comprehensive stipulation, which includes:

- Base rate revenue increase of \$62 million.
- ROE of 9.35% for purposes of filings related to (1) the Hale and Sagamore wind projects; and (2) reconciliation of the settlement revenue requirement.
- Equity ratio of 54.72%.
- Increase in depreciation expense of \$6 million. This includes a change in the depreciable lives of the Tolk power plant to 2032 and coal handling assets at the Harrington facility to 2024.

A public hearing is scheduled for July 26 - Aug. 6, 2021. A NMPRC decision and implementation of final rates is anticipated in the fourth quarter of 2021.

SPS — Texas 2021 Electric Rate Case — In February 2021, SPS filed an electric rate case with the Public Utilities Commission of Texas (PUCT) and its municipalities seeking an increase in base rates of approximately \$143 million. SPS’ net rate increase to Texas customers is expected to be approximately \$74 million, or 9.2%, as a result of the offsetting \$69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is based on a ROE of 10.35%, an equity ratio of 54.60%, a rate base of approximately \$3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020.

The request includes the effect of losing approximately 400 MW from a wholesale transmission customer and changes to depreciation lives of SPS’ Tolk power plant (from 2037 to 2032) and coal handling assets at the Harrington facility (to 2024).

Procedural schedule expected to be as follows:

- Intervenor testimony — Aug. 13, 2021.
- Staff testimony — Aug. 20, 2021.
- Rebuttal testimony — Sept. 15, 2021.
- Public hearing — Oct. 18 - Oct. 28, 2021.

Once final rates are approved, a surcharge will be requested from March 15, 2021 through the effective date of new base rates. A PUCT decision is expected in the first quarter of 2022.

Note 5. Winter Storm Uri

In February 2021, the central portion of the United States experienced a major winter storm (Winter Storm Uri). Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation across the region. 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 \$985 million (largely deferred as regulatory assets) in the first quarter. Certain energy transactions are subject to final/settlement calculation adjustments, including the impacts of credit losses shared among market participants.

Total incurred costs (net) per operating utility:

(Millions of Dollars)	
NSP-Minnesota	\$ 230
NSP-Wisconsin	45
PSCo	610
SPS	100
Total - Winter Storm Uri	\$ 985

In addition, higher market prices resulted in \$27 million of net gains (after customer sharing) related to proprietary commodity trading. These transactions were primarily entered into under Xcel Energy’s ordinary trading practices prior to Winter Storm Uri.

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 cost increases for future recovery and are proposing to recover the cost increases over a period of up to 27 months to mitigate the impact to customer bills. Additionally, we are not requesting recovery of financing costs in order to further limit the impact to our customers.

Proceedings initiated:

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	NSP-Minnesota filed with the MPUC seeking recovery of \$179 million in incremental costs from natural gas customers over 27 months with no financing charge and an additional \$36 million from natural gas customers through the standard 12 month true-up. Parties were generally supportive of the proposed recovery period commencing Sept. 1, 2021. The Department of Commerce recommended disallowances of \$21 million; the Office of the Attorney General recommended disallowances of \$34 million. A MPUC decision on the start of cost recovery is expected prior to Sept. 1, 2021. A proceeding related to the proposed disallowances is expected to continue into 2022.
	South Dakota	In April, NSP-Minnesota filed a letter with the South Dakota Public Utilities Commission (SDPUC) proposing no impact to the fuel clause as we were a net seller in the electric market. The SDPUC has approved the proposal.
	North Dakota	In June, the NDPSC approved recovery of \$32 million in natural gas costs over 15 months (starting July 2021) with no financing charge.
NSP-Wisconsin	Wisconsin	In March, the PSCW approved NSP-Wisconsin's proposal to recover \$45 million of natural gas costs incurred during Storm Uri over nine months through December 2021 with no financing charge.
	Michigan	In May, the Michigan Public Service Commission approved recovery of \$2 million in natural gas costs over 10 months with no financing charge.
PSCo	Colorado	In May, PSCo filed a request with the CPUC to recover \$263 million in weather-related electric costs, \$287 million in incremental gas costs and \$4 million in incremental steam costs over 24 months with no financing charge. A decision is expected in the first quarter of 2022. In addition, the CPUC is considering prospective changes in fuel cost recovery.
SPS	Texas	SPS filed for a surcharge in the second quarter to recover \$62 million in fuel costs over 24 months, subject to revision due to re-settlements. Prudence of costs will be subject to review in SPS's upcoming fuel reconciliation case.
	New Mexico	The NMPRC approved SPS's request to recover \$26 million of fuel costs over 24 months with no financing charge, subject to revision due to re-settlements and NMPRC review.

Note 6. Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2021 Earnings Guidance — Xcel Energy's 2021 GAAP and ongoing earnings guidance is a range of \$2.90 to \$3.00 per share.^(a)

Key assumptions as compared with 2020 levels unless noted:

- Constructive outcomes in all rate case and regulatory proceedings.
- Modest impacts from COVID-19.
- Normal weather patterns for the remainder of the year.
- Weather-normalized retail electric sales are projected to increase ~1%.
- Weather-normalized retail firm natural gas sales are projected to increase ~1%.
- Capital rider revenue is projected to increase \$100 million to \$110 million (net of PTCs). PTCs are credited to customers, through capital riders, fuel clause or base rates and results in a reduction to electric margin.
- O&M expenses are projected to increase 0% to 1%.
- Depreciation expense is projected to increase approximately \$155 million to \$165 million.
- Property taxes are projected to increase approximately \$40 million to \$50 million.
- Interest expense (net of AFUDC - debt) is projected to increase \$20 million to \$30 million.
- AFUDC - equity is projected to decline approximately \$40 million to \$50 million.
- ETR is projected to be (7%) to (8%). The ETR reflects benefits of PTCs which are credited to customers through electric margin and will not have a material impact on net income.

^(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 2020 base of \$2.78 per share, which represents the mid-point of the original 2020 guidance range of \$2.73 to \$2.83 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.

XCEL ENERGY INC. AND SUBSIDIARIES
EARNINGS RELEASE SUMMARY (UNAUDITED)
(amounts in millions, except per share data)

	Three Months Ended June 30	
	2021	2020
Operating revenues:		
Electric and natural gas	\$ 3,046	\$ 2,566
Other	22	20
Total operating revenues	3,068	2,586
Net income	\$ 311	\$ 287
Weighted average diluted common shares outstanding	539	527
Components of EPS — Diluted		
Regulated utility	\$ 0.62	\$ 0.60
Xcel Energy Inc. and other costs	(0.04)	(0.07)
GAAP and ongoing diluted EPS ^{(a)(b)}	\$ 0.58	\$ 0.54
Book value per share	\$ 27.43	\$ 25.39
Cash dividends declared per common share	0.4575	0.43

	Six Months Ended June 30	
	2021	2020
Operating revenues:		
Electric and natural gas	\$ 6,563	\$ 5,352
Other	46	45
Total operating revenues	6,609	5,397
Net income	\$ 673	\$ 582
Weighted average diluted common shares outstanding	539	527
Components of EPS — Diluted		
Regulated utility	\$ 1.35	\$ 1.20
Xcel Energy Inc. and other costs	(0.10)	(0.10)
GAAP and ongoing diluted EPS ^(a)	1.25	1.10
Book value per share	\$ 27.45	\$ 25.40
Cash dividends declared per common share	0.915	0.86

^(a) For the three and six months ended June 30, 2021, there were no adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

^(b) Amounts may not add due to rounding.