Exhibit 99.01

Jan. 27, 2022

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
2021 YEAR END EARNINGS REPORT

- 2021 earnings per share were $2.96 compared with $2.79 per share in 2020.
- Xcel Energy reaffirms 2022 EPS earnings guidance of $3.10 to $3.20 per share.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2021 GAAP and ongoing earnings of $1.60 billion, or $2.96 per share, compared with $1.47 billion, or $2.79 per share in the same period in 2020.

Earnings reflect higher electric and natural gas revenues, which were partially offset by increases in electric fuel and purchased power, costs of natural gas sold and transported, additional depreciation and lower allowance for funds used during construction (AFUDC).

"We had a solid year delivering earnings of $2.96 per share and achieving our earnings guidance for the 17th consecutive year. We are well positioned for the future and are reaffirming our 2022 ongoing EPS guidance of $3.10 - $3.20," said Bob Frenzel, chairman, president and CEO.

"We also reached constructive regulatory settlements in Colorado with our clean energy plan, the Colorado Power Pathway transmission investment plan and our electric rate case. Additionally, we reached a settlement in principle in our Texas rate case."

"Finally, I must extend my appreciation to the entire Xcel Energy team and our industry partners for their dedication and tireless work to help our Colorado customers impacted by the devastating wildfires and historic windstorm in December. It is inspiring to see how the entire community came together to support one another, and I am thankful for our employees and all those who have played a role in helping those who have lost so much."

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:	(800) 289-0720
International Dial-In:	(400) 120-9264
Conference ID:	4764710

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 Investors under Company. If you are unable to participate in the live event, the call will be available for replay from 12:00 p.m. CDT on Jan. 27 through 12:00 p.m. CDT on Jan. 30.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	4764710

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 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, 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, supply chain constraints and their impact on capital expenditures and/or 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.

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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 Dec. 31		Twelve Months Ended Dec. 31	
	2021	2020	2021	2020
Operating revenues				
Electric	$ 2,562	$ 2,372	$ 11,205	$ 9,802
Natural gas	768	554	2,132	1,636
Other	25	21	94	88
Total operating revenues	3,355	2,947	13,431	11,526
Operating expenses				
Electric fuel and purchased power	1,090	901	4,733	3,512
Cost of natural gas sold and transported	478	264	1,081	689
Cost of sales — other	10	9	38	37
Operating and maintenance expenses	569	616	2,321	2,324
Conservation and demand side management expenses	82	73	304	288
Depreciation and amortization	535	499	2,121	1,948
Taxes (other than income taxes)	158	159	630	612
Total operating expenses	2,922	2,521	11,228	9,410
Operating income	433	426	2,203	2,116
Other income (expense), net	—	—	5	(6)
Earnings from equity method investments	15	11	62	40
Allowance for funds used during construction — equity	20	24	73	115
Interest charges and financing costs				
Interest charges — includes other financing costs of $8, $7, $29 and $28, respectively	214	212	842	840
Allowance for funds used during construction — debt	(8)	(9)	(26)	(42)
Total interest charges and financing costs	206	203	816	798
Income before income taxes	262	258	1,527	1,467
Income tax benefit	(53)	(30)	(70)	(6)
Net income	$ 315	$ 288	$ 1,597	$ 1,473
Weighted average common shares outstanding:				
Basic	541	530	539	527
Diluted	542	532	540	528
Earnings per average common share:				
Basic	$ 0.58	$ 0.54	$ 2.96	$ 2.79
Diluted	0.58	0.54	2.96	2.79

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), 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.

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 twelve months ended Dec. 31, 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 earnings were $2.96 per share compared to $2.79 per share in 2020. The increase was driven by capital investment recovery and other regulatory outcomes, partially offset by increases in depreciation and lower AFUDC. 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 revenues are offset by the related variation in costs).

Summarized diluted EPS for Xcel Energy:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings (Loss) Per Share	**2021**	**2020**	**2021**	**2020**
PSCo	$ 0.27	$ 0.25	$ 1.22	$ 1.11
NSP-Minnesota	0.22	0.23	1.12	1.12
SPS	0.11	0.10	0.59	0.56
NSP-Wisconsin	0.05	0.04	0.20	0.20
Earnings from equity method investments — WYCO	0.01	0.01	0.05	0.05
Regulated utility [(a)]	0.65	0.63	3.18	3.04
Xcel Energy Inc. and Other	(0.06)	(0.09)	(0.22)	(0.25)
Total [(a)]	**$ 0.58**	**$ 0.54**	**$ 2.96**	**$ 2.79**

(a) Amounts may not add due to rounding.

PSCo — Earnings increased $0.11 per share for 2021, driven by capital investment recovery and other regulatory outcomes. Higher revenues were partially offset by increased depreciation, operating and maintenance (O&M) expenses and other taxes (other than income taxes).

NSP-Minnesota — Earnings were flat for 2021 compared to 2020, reflecting capital investment recovery offset by additional depreciation and interest charges.

SPS — Earnings increased $0.03 per share for 2021, largely related to capital investment recovery and other regulatory outcomes, lower income tax, O&M and interest expenses, partially offset by decreased AFUDC.

NSP-Wisconsin — Earnings were flat for 2021 compared to 2020.

Xcel Energy Inc. and Other — Primarily includes financing costs at the holding company, offset by earnings from Energy Impact Partners (EIP) investments.

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

Diluted Earnings (Loss) Per Share	**Three Months Ended Dec. 31**	**Twelve Months Ended Dec. 31**
GAAP and ongoing diluted EPS — 2020	**$ 0.54**	**$ 2.79**
Components of change — 2021 vs. 2020		
Higher electric revenues, net of electric fuel and purchased power	—	0.26
Lower ETR [(a)]	0.05	0.17
Higher natural gas revenues, net of cost of natural gas sold and transported	—	0.15
Lower O&M expenses	0.07	—
Changes in taxes (other than income taxes)	0.01	(0.03)
Lower AFUDC	(0.01)	(0.10)
Higher depreciation and amortization	(0.05)	(0.24)
Other (net)	(0.03)	(0.04)
GAAP and ongoing diluted EPS — 2021	**$ 0.58**	**$ 2.96**

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

ROE for Xcel Energy and its utility subsidiaries:

2021	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Operating Companies	Xcel Energy
GAAP and ongoing ROE	8.45 %	8.23 %	9.22 %	9.92 %	8.58 %	10.58 %

2020	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Operating Companies	Xcel Energy
GAAP and ongoing ROE	9.20 %	8.06 %	9.54 %	10.52 %	8.87 %	10.59 %

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 Dec. 31			Twelve Months Ended Dec. 31		
	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020
Retail electric	$ (0.026)	$ (0.005)	$ (0.021)	$ 0.096	$ 0.090	$ 0.006
Decoupling and sales true-up	0.011	0.003	0.008	(0.066)	(0.041)	(0.025)
Electric total	$ (0.015)	$ (0.002)	$ (0.013)	$ 0.030	$ 0.049	$ (0.019)
Firm natural gas	(0.030)	(0.006)	(0.024)	(0.025)	(0.011)	(0.014)
Total	$ (0.045)	$ (0.008)	$ (0.037)	$ 0.005	$ 0.038	$ (0.033)

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

	Three Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(6.6)%	(2.2)%	(13.7)%	(3.1)%	(5.6)%
Electric C&I	(1.4)	2.9	7.1	3.7	2.7
Total retail electric sales	(3.2)	1.2	3.2	1.6	0.3
Firm natural gas sales	(16.2)	(8.2)	N/A	(12.7)	(13.5)

	Three Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	(2.1)%	(1.4)%	(5.3)%	(2.0)%	(2.3)%
Electric C&I	(1.0)	2.5	7.3	3.6	2.8
Total retail electric sales	(1.4)	1.2	4.8	1.9	1.3
Firm natural gas sales	(0.6)	(4.4)	N/A	(9.9)	(2.3)

	Twelve Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	— %	2.2 %	(4.7)%	0.5 %	0.3 %
Electric C&I	0.4	2.3	2.9	3.6	2.0
Total retail electric sales	0.3	2.2	1.4	2.7	1.4
Firm natural gas sales	(1.1)	(4.0)	N/A	(5.0)	(2.2)

	Twelve Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	1.5 %	0.3 %	(1.0)%	(0.2)%	0.5 %
Electric C&I	0.4	1.7	3.3	3.3	1.9
Total retail electric sales	0.8	1.2	2.5	2.2	1.4
Firm natural gas sales	1.3	(2.2)	N/A	(4.1)	(0.1)

	Twelve Months Ended Dec. 31 (2020 Leap Year Adjusted)				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	1.7 %	0.6 %	(0.7)%	0.1 %	0.8 %
Electric C&I	0.7	1.9	3.6	3.6	2.1
Total retail electric sales	1.1	1.5	2.7	2.5	1.7
Firm natural gas sales	1.8	(1.7)	N/A	(3.6)	0.4

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

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 from pre-pandemic levels due to continuance of individuals working from home.

- PSCo — Residential sales rose based on a 1.2% increase in customers, combined with higher use per customer. The growth in C&I sales was due to a 1.2% increase in customers, partially offset by slightly lower use per customer, primarily in the services sector.
- NSP-Minnesota — Residential sales growth reflects a 1.2% increase in customers, partially offset by a lower use per customer. The growth in C&I sales was due to a 0.9% increase in customers and higher use per customer, primarily in the manufacturing, retail and services sectors.
- SPS — Residential sales declined as lower use per customer offset a 0.9% increase in customers. C&I sales increased due to a 0.5% increase in customers and higher use per customer, primarily driven by the oil and gas and professional services sectors.
- NSP-Wisconsin — Residential sales growth was attributable to a 0.8% increase in customer additions, partially offset by slightly lower use per customer. The growth in C&I sales was due to a 1.1% increase in customers, primarily led by increases in the manufacturing, health care and retail trade sectors.

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

- Natural gas sales primarily reflect a 1.2% increase in residential customers and a 0.5% increase in C&I customers, partially offset by a decrease in use per customer.

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 impact on earnings impact due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes. See Note 5 for discussion of Winter Storm Uri.

Electric revenues, fuel and purchased power and margin:

(Millions of Dollars)	Three Months Ended Dec. 31 2021	Three Months Ended Dec. 31 2020	Twelve Months Ended Dec. 31 2021	Twelve Months Ended Dec. 31 2020
Electric revenues	$ 2,562	$ 2,372	$ 11,205	$ 9,802
Electric fuel and purchased power	(1,090)	(901)	(4,733)	(3,512)
Electric margin	$ 1,472	$ 1,471	$ 6,472	$ 6,290

Change in electric margin:

(Millions of Dollars)	Three Months Ended Dec. 31, 2021 vs. 2020	Twelve Months Ended Dec. 31, 2021 vs. 2020
Non-fuel riders	$ 22	$ 221
Regulatory rate outcomes (Texas, Wisconsin, Colorado, New Mexico and North Dakota)	8	114
Proprietary commodity trading, net of sharing [(a)]	(8)	40
Sales and demand [(b)]	9	29
PTCs flowed back to customers (offset by lower ETR)	(37)	(149)
Texas 2019 rate case surcharge [(c)]	—	(70)
Estimated impact of weather (net of decoupling/sales true-up)	(9)	(12)
Other (net)	16	9
Increase in electric margin	$ 1	$ 182

(a) Includes $27 million of net gains previously recognized in the first quarter of 2021, driven by market changes associated with Winter Storm Uri. Additional amounts are primarily related to long-term physical generation contracts, which have increased in value as a result of higher energy prices.

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

(c) Impact is due to the Texas rate case outcome, which resulted in a revenue increase that was recognized in the third quarter of 2020 (largely offset by recognition of previously deferred costs).

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 expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas generally have minimal earnings impact due to cost recovery mechanisms. See Note 5 for discussion of Winter Storm Uri.

Natural gas revenues, cost of natural gas sold and transported and margin:

(Millions of Dollars)	Three Months Ended Dec. 31 2021	Three Months Ended Dec. 31 2020	Twelve Months Ended Dec. 31 2021	Twelve Months Ended Dec. 31 2020
Natural gas revenues	$ 768	$ 554	$ 2,132	$ 1,636
Cost of natural gas sold and transported	(478)	(264)	(1,081)	(689)
Natural gas margin	$ 290	$ 290	$ 1,051	$ 947

Change in natural gas margin:

(Millions of Dollars)	Three Months Ended Dec. 31, 2021 vs. 2020	Twelve Months Ended Dec. 31, 2021 vs. 2020
Regulatory rate outcomes (Colorado and North Dakota)	$ 7	$ 90
Infrastructure and integrity riders	4	12
Conservation incentive	2	3
Estimated impact of weather	(17)	(10)
Other (net)	4	9
Change	$ —	$ 104

O&M Expenses — O&M expenses decreased $3 million year-to-date. Increases for distribution, wind farm maintenance and technology costs were offset by a decrease in employee benefits expense (e.g., long-term incentives), additional Texas 2021 rate case deferrals and the year-over-year impact of amounts associated with the Texas 2019 rate case surcharge.

Depreciation and Amortization — Depreciation and amortization increased $173 million year-to-date. The increase was primarily driven by several wind farms going into service, normal system expansion and the implementation of new depreciation rates in various states.

Other Income (Expense) — Other income (expense) increased $11 million year-to-date. The change was largely related to gains associated with rabbi trust performance (offset in O&M expenses).

AFUDC, Equity and Debt — AFUDC decreased $58 million year-to-date. The decrease was driven by completion of various wind projects throughout 2020 and 2021.

Interest Charges — Interest charges increased $2 million year-to-date. The increase was largely due to higher debt levels to fund capital investments, partially offset by lower long-term and short-term interest rates.

***Earnings from Equity Method Investments* —** Earnings from equity method investments increased $22 million year-to-date. The year-to-date change 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 Dec. 31			Twelve Months Ended Dec. 31		
	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	4.8	0.1	5.0	4.9	0.1
Increases (decreases):						
Wind PTCs [a]	(39.9)	(27.7)	(12.2)	(23.4)	(15.7)	(7.7)
Plant regulatory differences [b]	(7.2)	(8.9)	1.7	(6.2)	(7.6)	1.4
Net operating loss (NOL) carryback	—	—	—	—	(0.9)	0.9
Other tax credits, NOL allowances (net) and tax credit allowances	(1.4)	(1.6)	0.2	(1.1)	(1.2)	0.1
Other (net)	2.4	0.8	1.6	0.1	(0.9)	1.0
Effective income tax rate	(20.2)%	(11.6)%	(8.6)%	(4.6)%	(0.4)%	(4.2)%

(a) Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on 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 credits are offset by corresponding revenue reductions.

Income tax benefit increased $64 million year-to-date. The change was driven by an increase in wind PTCs due to additional wind facilities going into service. Impact of PTCs was partially offset by an increase in pretax earnings, lower plant regulatory differences and lower non-plant accumulated deferred income tax amortization.

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

Xcel Energy's capital structure:

(Millions of Dollars)	**Dec. 31, 2021**	**Percentage of Total Capitalization**	**Dec. 31, 2020**	**Percentage of Total Capitalization**
Current portion of long-term debt	$ 601	1 %	$ 421	1 %
Short-term debt	1,005	3	584	2
Long-term debt	21,779	56	19,645	56
Total debt	23,385	60	20,650	59
Common equity	15,612	40	14,575	41
Total capitalization	$ 38,997	100 %	$ 35,225	100 %

Liquidity — As of Jan. 24, 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	$ 548	$ 702	$ 1	$ 703
PSCo	700	336	364	7	371
NSP-Minnesota	500	21	479	7	486
SPS	500	309	191	5	196
NSP-Wisconsin	150	117	33	1	34
Total	$ 3,100	$ 1,331	$ 1,769	$ 21	$ 1,790

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

Term Loan Agreements — In the fourth quarter of 2021, Xcel Energy paid off a $1.2 billion 364-Day Term Loan Agreement that was entered in February 2021 to enhance liquidity due to the incremental fuel costs from Winter Storm Uri and regulatory lag in recovery.

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 $45 million of outstanding letters of credits as of Dec. 31, 2021.

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 at-the-market offering (ATM) program. As of Dec. 31, 2021, Xcel Energy issued 5.33 million shares of common stock with net proceeds of $346.5 million through the ATM program.

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 Jan. 24, 2022:

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 issued approximately $74 million of equity through the Dividend Reinvestment Program and other benefit programs. In addition, Xcel Energy Inc. and its utility subsidiaries issued the following bonds:

Issuer	Security	Amount (Millions of Dollars)	Status	Tenor	Coupon
Xcel Energy Inc.	Unsecured Bonds	$ 500	Completed	5 Year	1.75 %
Xcel Energy Inc.	Unsecured Bonds	300	Completed	10 Year	2.35
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	Completed	30 Year	2.82

2022 Planned Financing Activities — During 2022, Xcel Energy Inc. and its utility subsidiaries anticipate the following:

- Xcel Energy Inc. — approximately $600 million in unsecured bonds during Q2.
- PSCo — approximately $650 million of first mortgage bonds during Q2.
- SPS — approximately $150 million of first mortgage bonds during Q2.
- NSP-Minnesota — approximately $500 million of first mortgage bonds during Q2.
- NSP-Wisconsin — approximately $100 million of first mortgage bonds during Q3.

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

Note 4. Rates and Regulation

NSP-Minnesota — 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 addition, NSP-Minnesota requested interim rates, subject to refund, of $288 million to be implemented in January 2022 and an incremental $135 million to be implemented in January 2023. In December 2021, the MPUC approved rates of $247 million to begin on Jan. 1, 2022. The adjusted level reflects exigent circumstances from the COVID-19 pandemic. The next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: Oct. 3, 2022
- Rebuttal testimony: Nov. 8, 2022
- Public hearing: Dec. 13-16, 2022
- Administrative Law Judge (ALJ) Report: March 31, 2023
- MPUC Order: June 30, 2023

NSP-Minnesota — 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 return on equity of 10.5%, rate base of $934 million and an equity ratio of 52.50%. In December 2021, the MPUC approved the requested interim rates of $25 million, subject to refund, beginning on Jan. 1, 2022. The next steps in the procedural schedule are expected to be as follows:

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

NSP-Minnesota — 2021 North Dakota Natural Gas Rate Case — In September 2021, NSP-Minnesota filed a request with the North Dakota Public Service Commission (NDPSC) for a natural gas rate increase of $7 million, or 10.49%. 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 approximately $140 million. Interim rates of $7 million, subject to refund, were implemented on Nov. 1, 2021. A NDPSC decision is expected in early fall 2022. The next steps in the procedural schedule are expected to be as follows:

- Intervenor testimony: March 1, 2022
- Rebuttal testimony: April 1, 2022
- Hearings: June 1-3, 2022

NSP-Wisconsin — Wisconsin Electric and Natural Gas Settlement — In December 2021, the PSCW approved a rate case settlement agreement and 2022 fuel cost plan without modification. New rates and tariffs were effective Jan. 1, 2022. Key elements of the settlement:

- An increase in electric rates of $35 million (4.9%) for 2022 and an incremental $18 million increase (2.5%) for 2023.
- An increase in natural gas rates of $10 million (8.4%) for 2022 and an incremental $3 million (2.3%) for 2023.
- 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.
- Incorporating an earnings sharing mechanism for 2022 and 2023.

NSP-Wisconsin — Michigan Electric Rate Case — In January 2022, NSP-Wisconsin reached an electric rate case settlement in principle with the Michigan Public Service Commission (MPSC) staff and others. The settlement grants NSP-Wisconsin an electric revenue increase of $1.6 million in 2022, based on a ROE of 9.7% and an equity ratio of 52.5%. The MPSC is expected to rule on the settlement in the first quarter of 2022.

PSCo — Colorado Electric Rate Request — In July 2021, PSCo filed a request with the Colorado Public Utilities Commission (CPUC) seeking a net electric rate increase 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 was based on a 10.0% ROE, an equity ratio of 55.64%, a 2022 forecast test year, a rate base of $10.3 billion and impacts of a new depreciation study.

In January 2022, PSCo reached an unopposed comprehensive settlement. The CPUC is expected to rule on the settlement in March 2022 with final rates expected to be effective in April 2022. Key settlement terms include:

- A net electric rate increase of $177 million. The total change in base rates is $299 million, which includes $122 million of revenue previously collected through various rider mechanisms.
- A ROE of 9.3% and an equity ratio of 55.69%.
- A current 2021 test year (average rate base) with the transfer of Cheyenne Ridge, Wildfire Mitigation Plan and Advanced Grid Intelligence and Security (AGIS) investments at year-end rate base.
- Approval of all of PSCo’s proposed depreciation adjustments.
- Continuation of the property tax, qualified pension, and non-qualified pension trackers.
- Continuation of AGIS deferral including interest equivalent to PSCo's weighted average cost of capital once the balance exceeds $50 million.
- Continuation of the Wildfire Mitigation Plan deferral, with a debt return.

PSCo — Resource Plan Settlement — In November 2021, PSCo and multiple intervenors filed a partial settlement of the resource plan, which will result in an expected 87% carbon reduction and an 80% renewable mix by 2030. A CPUC decision is expected in the first quarter of 2022. Key settlement terms include:

- Early retirement of Hayden: Unit 2 in 2027 (was 2036); and Unit 1 in 2028 (was 2030).
- Conversion of Pawnee to burn natural gas by 2026.
- Early retirement of Comanche 3 in 2034 with reduced operations beginning in 2025.
- Addition of ~2,300 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.

PSCo — Pathway Transmission Expansion Settlement — In November 2021, PSCo filed a non-unanimous settlement agreement with Staff and several other parties regarding its CPCN request for the Pathway Transmission project. Key settlement terms include:

- The parties agreed that PSCo met the burden of proof demonstrating that the project was needed to facilitate the renewables in the Integrated Resource Plan (IRP) and is in the public interest.
- Agreed to a cost estimate of $1.7 billion and recovery through the transmission rider.
- The Pathway project will also include a Performance Incentive Mechanism such that applicable costs in a given year above or below a 5% dead band would allow for a ROE penalty or adder.
- Parties agreed to conditional CPCN approval for 345 kV extension project subject to the project being included in the final approved IRP plan with a cost estimate of $247 million.

PSCo — Natural Gas Rate Case — On Jan. 24, 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 Pipeline System Integrity Adjustment (PSIA) rider, which was closed to new investments at the end of 2021. The request is based on a 10.25% ROE, an equity ratio of 55.66% and a 2022 current test year. PSCo has requested a proposed effective date of Nov. 1, 2022.

Additionally, PSCo's request includes step revenue increases of $40 million in 2023 (effective Nov. 1, 2023) and $41 million in 2024 (effective Nov. 1, 2024) related to continued capital investment. Under this proposal, PSCo would not request another base rate change prior to Nov. 1, 2025. An informational historical test year including a 10.75% ROE was also filed as required by the CPUC.

The request supports fundamental infrastructure investments to serve customers, consistent with PSCo's obligation to provide safe, reliable service while enabling PSCo to continue to be a leader of the clean energy transition in partnership with the CPUC to achieve clean heat goals.

Revenue Request (millions of dollars)	**2022**
Changes since 2020 rate case:	
Plant related investments [(a)]	$ 210
Operations and maintenance, amortization and other expenses	11
Property tax expense	11
Sales growth	(17)
Net increase to revenue	**215**
Previously authorized costs:	
Transfer of costs previously recovered through the PSIA rider	(108)
Total base revenue request	**$ 107**
Projected 2022 year-end rate base (billions of dollars)	**$ 3.6**

[(a)] Includes approximately $28 million as a result of the increase in ROE from 9.2% to 10.25%.

SPS — New Mexico 2021 Electric Rate Case — In January 2021, SPS filed an electric rate case with the New Mexico Public Regulation Commission (NMPRC) with a current requested base rate increase of approximately $84 million.

In June 2021, SPS and various parties filed an uncontested stipulation with the NMPRC, which reflected a $62 million rate increase, a change in the depreciation life of the Tolk coal plant to 2032, an equity ratio of 54.72% and ROE of 9.35% for reconciliation statements and determining the revenue requirements for the Sagamore and Hale wind projects. In December 2021, the Hearing Examiner issued a recommendation that the NMPRC approve the rate case settlement agreement without modification. A NMPRC decision and implementation of final rates is anticipated in the first quarter of 2022.

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 $140 million. SPS' net rate increase to Texas customers is expected to be approximately $71 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).

On Jan. 26, 2022, SPS and intervenors filed a blackbox settlement. Key terms include:

- A base rate increase of approximately $89 million effective back to March 15, 2021.
- A 9.35% ROE and 7.01% weighted average cost of capital for AFUDC purposes only.
- The depreciation lives for Tolk moved up to 2034 and Harrington coal assets moved up to 2024.

A PUCT decision is expected in the first quarter of 2022.

Note 5. 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 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.

Proceedings initiated:

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	NSP-Minnesota filed with the MPUC seeking recovery of $215 million in incremental costs from natural gas customers. In August 2021, the MPUC allowed recovery of $179 million of costs deemed to be extraordinary beginning in September 2021 over 27 months (no financing charge) and $36 million of ordinary costs over 12 months through the monthly Purchased Gas Adjustment. The $179 million in extraordinary cost recovery is subject to refund pending the outcome of a contested case before an ALJ. In December 2021, the MPUC approved extending recovery of Winter Storm Uri costs for the residential class (approximately $97 million) from a 27-month recovery period to a 63-month recovery period. New residential Winter Storm Uri rates were effective Jan. 1, 2022. In December 2021, direct testimony was received from intervenors. The Department of Commerce (DOC) recommended a $127 million disallowance based on allegations including peaking plant usage, load forecasting, natural gas supply/storage and related purchases. Alternatively, the DOC recommended a $42 million disallowance if NSP-Minnesota proves it prudently managed its peaking plants. The Office of the Attorney General (OAG) recommended a disallowance of $179 million based on allegations that NSP-Minnesota could have fully hedged its exposure to spot market prices. Alternatively, the OAG recommended a $25 million disallowance based on allegations related to specific hedges allegedly available in the market during February 2021. The Citizens Utility Board (CUB) recommended a $69 million disallowance based on allegations related to the unavailability of NSP-Minnesota's peaking plants, inaccuracy of load forecasting and inadequate curtailment of interruptible customers. Xcel Energy strongly disagrees with the recommendations of the DOC, OAG and CUB and believes that it acted prudently and according to MPUC approved procedures for the best interest of its customers and stakeholders. NSP-Minnesota filed rebuttal testimony in January 2022. A hearing before the ALJs assigned to the matter is scheduled for Feb. 17-23, 2022. A MPUC decision is expected in the summer of 2022.
	South Dakota	Winter Storm Uri had no impact on South Dakota electric costs as NSP-Minnesota was a net seller in the electric market.
	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.

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Wisconsin	Wisconsin	In March, the PSCW approved NSP-Wisconsin's proposal to recover $45 million of Uri natural gas costs 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 natural gas costs and $4 million in incremental steam costs over 24 months with no financing charge. In September, intervenors filed testimony. The CPUC Staff recommended disallowances of approximately $99 million (electric) and $105 million (natural gas). Additionally, they proposed to net approximately $50 million of regulatory liabilities (decoupling related) from electric costs. The Colorado Office of the Utility Consumer Advocate (UCA) recommended disallowances of approximately $131 million. The Colorado Energy Office (COEO) recommended disallowances of approximately $46 million for not utilizing demand response programs during the event. In October, a partial settlement was reached with the CPUC Staff and the COEO, allowing full recovery of Winter Storm Uri deferred net natural gas, fuel and purchased energy costs 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. A decision is expected in the first quarter of 2022. In addition, the CPUC is considering prospective changes in fuel cost recovery.
SPS	Texas	As part of the Texas fuel surcharge filing, SPS filed for recovery of $76 million, over 24 months, in under-collected purchased power and fuel costs through March 2021, subject to revision due to re-settlements. Of this amount, $62 million was attributed to Winter Storm Uri. In the third quarter, SPS filed a supplemental application and testimony to recover an additional $26 million in under-collected purchased power and fuel costs through June 2021 resulting primarily from Southwest Power Pool resettlements and continued increases in natural gas prices. In November 2021, the ALJ abated the hearing schedule to allow the parties to continue settlement negotiations. In December 2021, SPS filed its triennial Fuel Reconciliation, under which the PUCT will consider prudence of SPS' fuel costs for the period July 2018 - June 2021, including Winter Storm Uri. In January 2022, SPS and other parties filed a stipulation/motion for interim rates. The filing covers all fuel under-collections occurring between January 2020 and August 2021, totaling $121 million. The settlement does not address the prudence of Winter Storm Uri costs nor the retention of $11 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. Interim rates, designed to collect up to $110 million over a period of 30 months, will begin on Feb. 1, 2022.
	New Mexico	The NMPRC approved SPS' request to recover $26 million of fuel costs over 24 months with no financing charge, subject to NMPRC review.

Note 6. 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 year.
- Weather-normalized retail electric sales are projected to increase ~1%.
- Weather-normalized retail firm natural gas sales are projected to be 0% to 1%.
- Capital rider revenue is projected to increase $35 million to $45 million (net of PTCs). PTCs are credited to customers, through capital riders and reductions to other regulatory mechanisms.
- O&M expenses are projected to increase approximately 1% to 2%.
- Depreciation expense is projected to increase approximately $255 million to $265 million.
- Property taxes are projected to increase approximately $40 million to $50 million.
- Interest expense (net of AFUDC - debt) is projected to increase $55 million to $65 million.
- AFUDC - equity is projected to be relatively flat.
- ETR is projected to be ~(3%) to (5%). 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 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.

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

	Three Months Ended Dec. 31	
	2021	**2020**
Operating revenues:		
Electric and natural gas	$ 3,330	$ 2,926
Other	25	21
Total operating revenues	3,355	2,947
Net income	$ 315	$ 288
Weighted average diluted common shares outstanding	542	532
Components of EPS — Diluted		
Regulated utility	$ 0.65	$ 0.63
Xcel Energy Inc. and other costs	(0.06)	(0.09)
GAAP and ongoing diluted EPS [(a)(b)]	**$ 0.58**	**$ 0.54**
Book value per share	$ 28.83	$ 27.40
Cash dividends declared per common share	0.4575	0.43

	Twelve Months Ended Dec. 31	
	2021	**2020**
Operating revenues:		
Electric and natural gas	$ 13,337	$ 11,438
Other	94	88
Total operating revenues	13,431	11,526
Net income	$ 1,597	$ 1,473
Weighted average diluted common shares outstanding	540	528
Components of EPS — Diluted		
Regulated utility	$ 3.18	$ 3.04
Xcel Energy Inc. and other costs	(0.22)	(0.25)
GAAP and ongoing diluted EPS [(a)(b)]	**$ 2.96**	**$ 2.79**
Book value per share	$ 28.93	$ 27.60
Cash dividends declared per common share	1.83	1.72

[(a)] For the three and twelve months ended Dec. 31, 2021 and 2020, there were no adjustments to GAAP earnings.
[(b)] Amounts may not add due to rounding.