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

(Mark One)

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

For the fiscal year ended December 31, 2021 or

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

For the transition period from _____ to _____

001-3034
(Commission File Number)

Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
414 Nicollet Mall Minneapolis Minnesota	**55401**
(Address of Principal Executive Offices)	(Zip Code)

612 330-5500
(Registrant's Telephone Number, Including Area Code)

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

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

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
☒ Yes ☐ No

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

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

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒ Yes

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

As of June 30, 2021, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $35,463,594,471.

As of Feb. 17, 2022, there were 544,213,730 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement for its 2022 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K.

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PART I
ITEM 1 — BUSINESS

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

Capital Services	Capital Services, LLC
Eloigne	Eloigne Company
e prime	e prime inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
Operating companies	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

CPUC	Colorado Public Utilities Commission
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DSM	Demand side management
ECA	Retail electric commodity adjustment
FCA	Fuel clause adjustment
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PSIA	Pipeline system integrity adjustment
RES	Renewable energy standard
TCR	Transmission cost recovery

Other

AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ATM	At-the-market
BART	Best available retrofit technology
C&I	Commercial and Industrial
CAGR	Corporate annual growth rate
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CDD	Cooling degree-days
CEO	Chief executive officer
CFO	Chief financial officer
CIG	Colorado Interstate Gas Company, LLC
COEO	Colorado Energy Office
CON	Certificate of Need
COVID-19	Novel coronavirus
CUB	Citizens Utility Board
CWA	Clean Water Act
CWIP	Construction work in progress
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DECON	Decommissioning method where radioactive contamination is removed and safely disposed of at a requisite facility or decontaminated to a permitted level
DRIP	Dividend Reinvestment Program
EEI	Edison Electric Institute
EIP	Energy Impact Partners
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
ESG	Environmental, Social and Governance
ETR	Effective tax rate
EVs	Electric Vehicles
FASB	Financial Accounting Standards Board
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
HDD	Heating degree-days
INPO	Institute of Nuclear Power Operations
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producing entity
ISO	Independent System Operator
ITC	Investment Tax Credit
LP&L	Lubbock Power & Light
MEC	Mankato Energy Center
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
NAAQS	National Ambient Air Quality Standard
Native load	Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NOL	Net operating loss
NOPR	Notice of proposed rulemaking
O&M	Operating and maintenance
OAG	Minnesota Office of the Attorney General
OATT	Open Access Transmission Tariff
PFAS	Per- and PolyFluoroAlkyl Substances
PI	Prairie Island nuclear generating plant
Post-65	Post-Medicare
PPA	Purchased power agreement
Pre-65	Pre-Medicare
PTC	Production tax credit
REC	Renewable energy credit

ROE	Return on equity
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
THI	Temperature-humidity index
TO	Transmission owner
TSR	Total shareholder return
VaR	Value at Risk
VIE	Variable interest entity

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

Where to Find More Information

Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC.

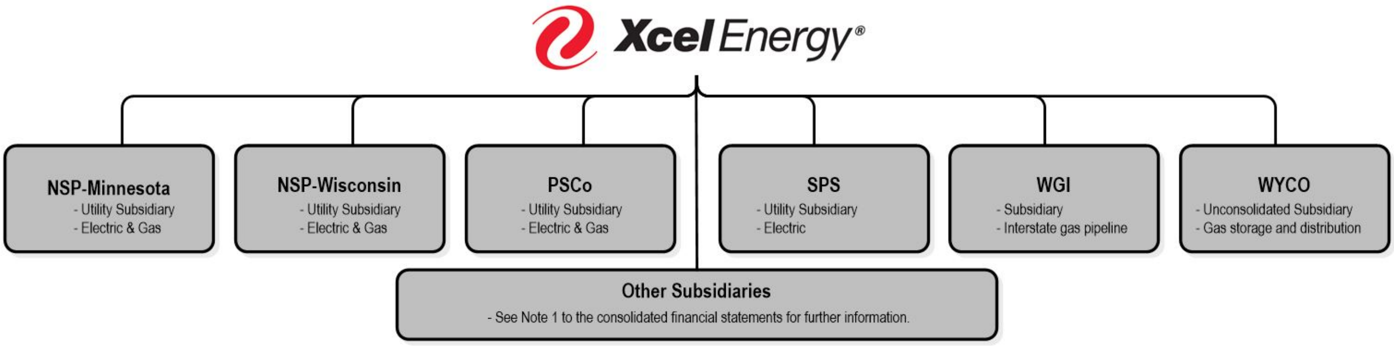
The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov. The information on Xcel Energy's website is not a part of, or incorporated by reference in, this annual report on Form 10-K. Xcel Energy intends to make future announcements regarding Company developments and financial performance through its website, www.xcelenergy.com, as well as through press releases, filings with the SEC, conference calls and webcasts.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to 2022 EPS guidance, long-term EPS and dividend growth rate objectives, future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2021 (including risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic, including potential workforce impacts resulting from vaccination requirements, quarantine policies or government restrictions, and sales volatility; operational safety, including our nuclear generation facilities and other utility operations; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; ability to recover costs; changes in regulation and subsidiaries' ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations, supply chain constraints and their impact on capital expenditures and/or the ability of Xcel Energy 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; costs of potential regulatory penalties; and regulatory changes and/or limitations related to the use of natural gas as an energy source.

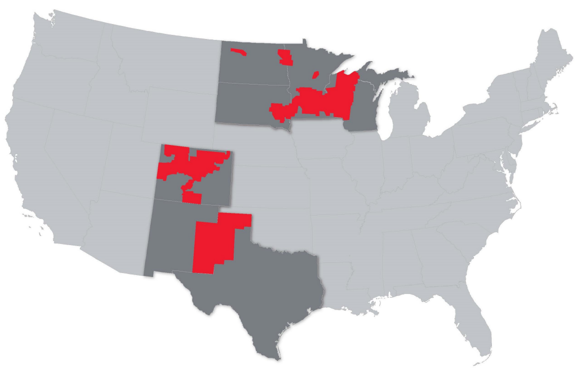
Overview

Xcel Energy (the "Company") is a major U.S. regulated electric and natural gas delivery company headquartered in Minneapolis, Minnesota (incorporated in Minnesota in 1909). Xcel Energy serves customers in eight mid-western and western states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Xcel Energy provides a comprehensive portfolio of energy-related products and services to approximately 3.7 million electric customers and 2.1 million natural gas customers through four utility subsidiaries (i.e., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS). Along with the utility subsidiaries, the transmission-only subsidiaries, WYCO (a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities) and WGI (an interstate natural gas pipeline company) comprise the regulated utility operations. Xcel Energy's nonregulated subsidiaries include Eloigne, Capital Services, Venture Holdings and Nicollet Project Holdings.



Utility Subsidiaries' Service Territory

Electric customers	3.7 million
Natural gas customers	2.1 million
Total assets	$57.9 billion
Electric generating capacity	20,653 MW
Natural gas storage capacity	53.4 Bcf
Electric transmission lines (conductor miles)	111,434 miles
Electric distribution lines (conductor miles)	210,470 miles
Natural gas transmission lines	2,293 miles
Natural gas distribution lines	36,510 miles



Strategy

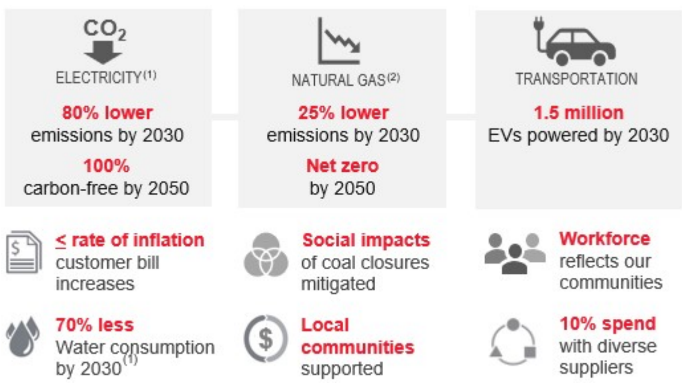
Xcel Energy strives to be the preferred and trusted provider of the energy our customers need, while offering a competitive total return to shareholders. We deliver on our vision through three strategic priorities:

LEAD THE CLEAN ENERGY TRANSITION | **ENHANCE THE CUSTOMER EXPERIENCE** | **KEEP BILLS LOW**

Sustainability is embedded in our strategy. We are retiring coal plants, adding renewables, exploring new technologies and helping to electrify other sectors, while maintaining customer affordability and supporting our employees and communities.

We are the first U.S. energy provider to set aggressive goals for reducing GHG emissions across three large sectors of the economy: electricity, natural gas use in buildings and transportation.

Our sustainability commitments include:



(1) Includes owned and purchased electricity provided to customers.
(2) Spans natural gas supply, distribution and customer use; includes net-zero methane emissions on our natural gas system by 2030.

We demonstrate environmental, social and governance leadership by engaging with stakeholders and mitigating risk, while staying committed to our customers, employees and communities.

Rooted in a culture of compliance and ethical conduct, our decisions and actions are guided by our Code of Conduct and our four values:

Connected **Committed** **Safe** **Trustworthy**

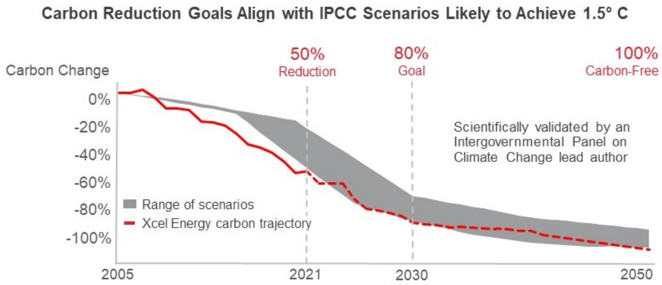
These values are reinforced by policies that govern safety practices, ethical standards and conduct, environmental performance, diversity and inclusion, political contributions, and other aspects of our business.

Our values, culture and Code of Conduct serve as the foundation upon which Xcel Energy's Board of Directors, employees, contractors and suppliers approach their work in delivering on our three strategic priorities.

Lead the Clean Energy Transition

For more than a decade, Xcel Energy has proactively managed the risk of climate change and worked to meet increasing demand for cleaner energy.

Xcel Energy was the first major U.S. utility to establish a carbon-free vision, targeting 100% carbon-free electricity by 2050 and an interim goal of 80% reduction in carbon emissions by 2030 (from 2005 levels), including owned and purchased power. A lead author for the IPCC confirmed that our vision aligns with science-based scenarios likely to limit global warming to 1.5 degrees Celsius from pre-industrial levels.



Goal includes owned and purchased power.

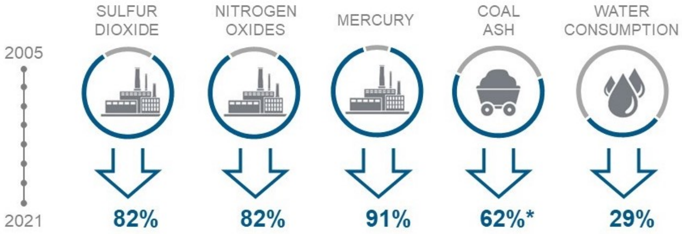
The pace of achieving a carbon-free vision is governed by reliability and customer affordability. Our filed resource plans outline a clear, transparent path to achieve an 80% carbon reduction using current technologies, while maintaining customer bill increases at or below the rate of inflation. Moving from 80% carbon reduction to 100% carbon-free electricity will require new dispatchable and scalable technologies that are economically viable, as well as supportive public policy. Resiliency and innovation also remain paramount to a successful transition, as does the economic vitality of our communities.

As we prepare for early coal plant retirements, we provide employees advanced notice and offer retraining and relocation opportunities, with no layoffs to date. We also help attract and make investments to offset community economic impacts. Xcel Energy has a long track record of working with our communities on energy, climate and environmental initiatives that impact them and has publicly committed to furthering environmental justice.

We consistently set aggressive goals and hold ourselves accountable to our customers, communities and investors, as well as, to our own values. Xcel Energy instituted oversight of environmental performance by the Board of Directors beginning in 2000 and was among the first U.S. utilities to tie carbon reduction to executive compensation over fifteen years ago.

Through 2021, we reduced carbon emissions from generation serving customers by an estimated 50% (from 2005 levels) and remain on track to achieve 80% carbon reduction by 2030.

Other notable environmental improvements include:



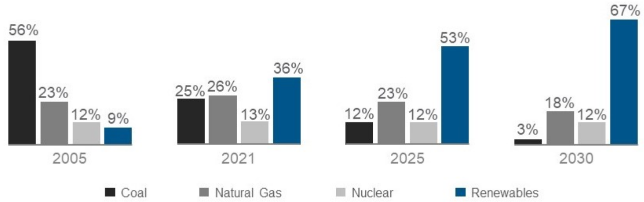
Results from owned generation except for water, which includes owned and purchased power.

* Coal ash reduction is as of 2020.

Xcel Energy has provided a voluntary, third-party verified annual GHG disclosure since 2005, longer than any other U.S. utility. We are a founding member of The Climate Registry and a supporter of the Task Force on Climate-Related Financial Disclosures. Our disclosures also align with the Global Reporting Initiative, Sustainability Accounting Standards Board and United Nations Sustainable Development Goals frameworks.

Since year-end 2020, we have completed four wind farms, adding ~800 MW (includes the Dakota Range project which went in service in January 2022) of owned wind to our system that provides significant environmental benefits and cost savings for our customers. Xcel Energy's wind capacity is now over 11,000 MW, including nearly 4,500 MW of owned wind.

By 2030, we project that approximately 80% of our energy will come from carbon-free resources.



Based on resource plans filed in Minnesota and Colorado, Xcel Energy anticipates nearly 10,000 MW of additional renewables over the next decade, and expects to be coal-free by 2034.

Colorado resource plan — settlement pending CPUC approval

- 87% carbon reduction by 2030 and full coal exit by 2034.
- ~3,900 MW of wind and solar additions.
- ~1,700 MW of flexible resources and storage.
- ~1,200 MW of distributed solar generation.

Minnesota resource plan — approved by MPUC

- 85% carbon reduction and full coal exit by 2030.
- 4,650 MW of wind and solar additions by 2032; the plan includes an additional 1,100 MW of renewables beyond 2032.
- Transmission infrastructure to connect new renewables to the grid.
- Extension of the Monticello nuclear plant through 2040.
- ~3,800 MW of firm peaking capacity for reliability before 2030, including hydrogen-ready combustion turbines, the combustion turbines will need to go through a CON process.
- Additional ~2,100 MW of firm capacity and storage post 2030, to be addressed in future proceedings.

Texas and New Mexico

- Proposed full coal exit by 2034 upon early retirement of our Tolk plant.
- Conversion of our Harrington coal plant to natural gas.

We plan to limit coal usage through dispatching units seasonally where possible. Natural gas and other dispatchable resources will be used as needed for reliability and resiliency as more renewables come on the system.

Significant transmission expansion will be required to enable future renewables. Our Pathway project (if approved) in Colorado will provide over 560 miles of transmission lines and enable nearly 5,500 MW of new renewables, including access to some of the region's richest wind resources. We also anticipate expansion in the Upper Midwest over the next decade as part of MISO's transmission expansion planning effort, creating investment opportunity.

Our clean energy leadership encompasses our natural gas business as well. In 2021, we committed to reduce GHG emissions by 25% by 2030 from 2020 levels and deliver net-zero natural gas service by 2050, including customer use.

Plans include:

- Influencing suppliers - pursue certified low/no net emissions supply.
- Operating the cleanest possible system – incorporate clean fuels.
- Offering customer options – encourage electrification, where beneficial.

Xcel Energy's leadership also extends beyond our electric and gas businesses to other parts of the economy. In addition to transitioning our own generation fleet, we are helping to decarbonize other sectors, starting with transportation. We aim to enable 1.5 million EVs across our states by 2030, representing a nearly $2 billion investment, 0.6% to 0.7% incremental annual retail sales growth and avoidance of roughly 5 million tons of CO_2 emissions annually.

Enhance the Customer Experience

Xcel Energy has a comprehensive suite of renewable and conservation programs that provide customers with clean energy options and help keep their bills low. We are also transforming and expanding our electric grid to accommodate increased load growth, renewable energy and distributed energy resources.

In 2021, Xcel Energy installed over 300,000 smart meters and plans to install more than one million in 2022. Xcel Energy also launched 12 EV programs for residential and commercial customers, received approval of our New Mexico plan, and continued to prepare for increased levels of EV adoption across our states.

For our local communities, we initiated 20 economic development projects in 2021, which are projected to lead to over $1 billion in capital investments and 5,000 jobs. Additionally, over 60% of our supply chain spend was local.

Keep Bills Low

Customer affordability is critical to successful strategy execution and we are working to keep bill increases at or below the rate of inflation. Since 2013, we have managed average residential bill growth to below 1% annually, with electric and natural gas bill increases of 0.8% and 0.3%, respectively.

Xcel Energy has invested more than $2 billion over the past decade in a comprehensive suite of conservation programs. We have kept O&M expenses flat since 2014, while adding significant renewables and without compromising safety or reliability.

Xcel Energy continues to prudently invest in appropriate areas consistent with its continuing commitment to minimize costs through ongoing process and technology improvements.

Our geographic advantages in wind and solar also enable customer savings, which we call our "Steel for Fuel" strategy. High capacity factors, coupled with renewable tax credits and avoided fuel costs, enable Xcel Energy to add renewables while saving customers money. To date, we have delivered more than $1.8 billion in customer savings by adding owned wind to our system.

In addition to continued savings from economic renewables, disciplined cost control and future coal plant retirements, we anticipate sales growth from electric vehicles will help keep bills low for all customers in the long term, as well as provide customers with annual fuel savings (equivalent cost per gallon for fueling with electricity vs. gasoline) of approximately $1 billion by 2030.

Deliver a Competitive Total Return to Investors

Successful strategy execution, along with our disciplined approach to growth, operations and management of environmental, social and governance issues, positions us to continue delivering a competitive TSR.

We have consistently achieved our financial objectives, meeting or exceeding our initial earnings guidance range for 17 consecutive years and delivering dividend growth for 18 consecutive years.

Over the past five years, GAAP earnings have grown by 6% annually and our annual dividend growth was 6.1%. Xcel Energy works to maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range. Current ratings are consistent with this goal.

Human Capital

Xcel Energy employees are the driving force behind our Company's success. Our strategic, data-driven approach to workforce planning helps ensure we will continue to have the skills and capabilities required to meet the evolving needs of our business, customers and communities. We are also deeply committed to diversity, equity, human rights and safety.

Safety

Continuously elevating the quality and safety of the workplace is a top priority. We are considered a benchmark company for our Safety Always approach, focused on eliminating life-altering injuries through a trusted, transparent culture and the use of critical controls. All employees have "stop work authority" and are expected to keep each other, our customers and the public safe. Employees are encouraged to speak up, share experiences and learn from events to help protect themselves, their coworkers and the public.

The Board of Directors has oversight for employee and public safety through the Operations, Nuclear, Environmental and Safety committee, both of which are also tied to annual incentive compensation.

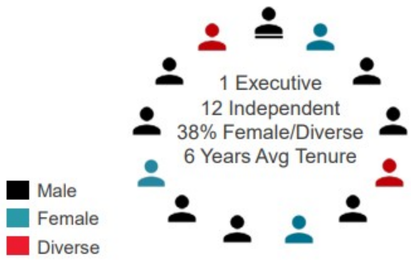
Benefits

Xcel Energy offers a competitive benefits package, including: performance-based compensation, supported by a management system that emphasizes ongoing coaching conversations. Benefits also include floating holidays and recognition, retirement and holistic well-being programs.

Management continuously evaluates benefits to maintain a market competitive, performance-based, shareholder-aligned total rewards package that supports our ability to attract, engage and retain a talented and diverse workforce, while reinforcing and rewarding strong performance.

Diversity, Equity, Inclusion and Human Rights

We aim to create an inclusive culture where employees are treated equitably, and diversity is not only accepted but celebrated. This starts with our Board of Directors, of which eight members were elected in the past five years.



The Board of Directors oversees our workforce strategy, including diversity and inclusion initiatives. In 2021, Xcel Energy added an incentive-based metric focused on diverse interview panels, executive sponsorship and employee feedback on inclusion in the workplace. A total of 70% of annual incentive pay was tied to safety, system reliability and diversity, equity and inclusion metrics.

In 2021, nearly all offers made had diverse hiring panels and executive sponsors consistently met with their employee counterparts at least monthly. We have also disclosed our Equal Employment Opportunity Employer Information Report (EEO-1).

Our CEO and senior executives lead by example, fostering an open and inclusive work environment through their interactions, communications and personal sponsorship of diverse talent throughout the organization.

We partner with educational and community organizations to attract and hire diverse employees who reflect the communities we serve and live our values. Workforce demographics as of December 2021 (unless otherwise noted):

	Female	Ethnically Diverse
Board of Directors [(a)]	23 %	15 %
CEO direct reports [(a)]	36 %	18 %
Management	22 %	11 %
Employees	24 %	17 %
New hires	39 %	26 %
Interns (hired throughout 2021)	34 %	27 %

(a) Demographics as of Feb. 1, 2022.

Veteran hiring is also a focus, with roughly 10% of employees having served in the military.

To help foster a culture of inclusivity, leaders and employees receive training on microinequities and unconscious bias. The Company hosts 11 business resource groups to support employee interests and obtain diverse perspectives when solving challenges and achieving goals.

Xcel Energy also respects employees' freedom of association and their right to collectively organize. As of Dec. 31, 2021, approximately 44% of our employees were covered by collective bargaining agreements.

	Employees Covered by Collective Bargaining Agreements	Total Full-Time Employees
NSP-Minnesota	2,020	3,083
NSP-Wisconsin	382	518
PSCo	1,818	2,314
SPS	736	1,099
XES	—	4,307
Total	4,956	11,321

Employee turnover for 2021 and future projected retirement eligibility:

Employee Turnover	
Bargaining	7 %
Non-Bargaining	15 %
Overall [(a)]	12 %

Retirement Eligibility	
Within next 5 years	26 %
Within next 10 years	40 %

(a) 31% of turnover was due to retirements.

Xcel Energy has publicly confirmed our commitment to the advancement and protection of human rights, consistent with U.S. human rights laws and the general principles in the International Labour Organization Conventions. Code of Conduct training is required for all employees annually and the Board of Directors.

The Company does not tolerate Code violations or other unacceptable behaviors. We expect and offer employees multiple avenues to raise concerns or report wrong-doing and do not permit any retaliation.

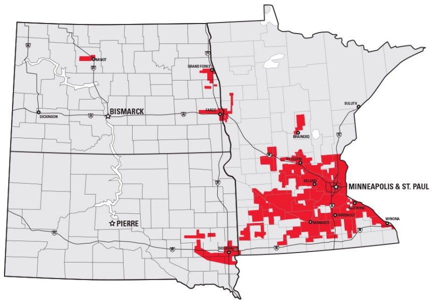
Xcel Energy recently received the following recognitions:

Fortune	Human Rights Campaign	GI Jobs	Military Times
World's Most Admired Companies	Best Places to Work for LGBTQ Equality	Military Friendly Employer	Best for Vets

Utility Subsidiaries

NSP-Minnesota

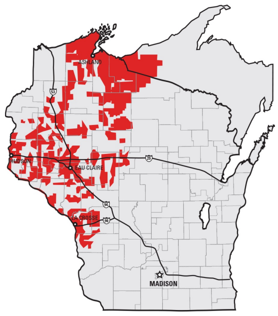
Electric customers	1.5 million
Natural gas customers	0.5 million
Total assets	$22.8 billion
Rate Base (estimated)	$13.7 billion
ROE (net income / average stockholder's equity)	8.45%
Electric generating capacity	8,628 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	34,155 miles
Electric distribution lines (conductor miles)	81,406 miles
Natural gas transmission lines	85 miles
Natural gas distribution lines	10,741 miles



NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSP-Wisconsin

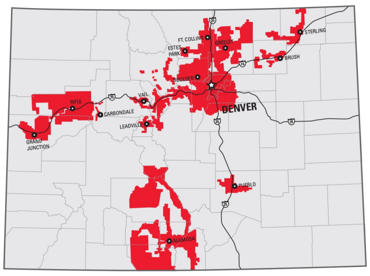
Electric customers	0.3 million
Natural gas customers	0.1 million
Total assets	$3.1 billion
Rate Base (estimated)	$2.0 billion
ROE (net income / average stockholder's equity)	9.92%
Electric generating capacity	548 MW
Gas storage capacity	3.8 Bcf
Electric transmission lines (conductor miles)	12,409 miles
Electric distribution lines (conductor miles)	27,701 miles
Natural gas transmission lines	3 miles
Natural gas distribution lines	2,526 miles



NSP-Wisconsin conducts business in Wisconsin and Michigan and generates, transmits, distributes and sells electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

PSCo

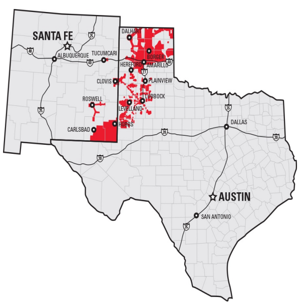
Electric customers	1.5 million
Natural gas customers	1.5 million
Total assets	$22.0 billion
Rate Base (estimated)	$14.0 billion
ROE (net income / average stockholder's equity)	8.23%
Electric generating capacity	6,228 MW
Gas storage capacity	32.5 Bcf
Electric transmission lines (conductor miles)	24,116 miles
Electric distribution lines (conductor miles)	78,712 miles
Natural gas transmission lines	2,174 miles
Natural gas distribution lines	23,243 miles



PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

SPS

Electric customers	0.4 million
Total assets	$9.3 billion
Rate Base (estimated)	$6.4 billion
ROE (net income / average stockholder's equity)	9.22%
Electric generating capacity	5,249 MW
Electric transmission lines (conductor miles)	40,754 miles
Electric distribution lines (conductor miles)	22,651 miles



SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.

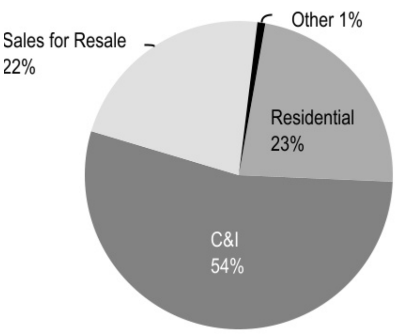
Operations Overview

Utility operations are generally conducted as either electric or gas utilities in our four utility subsidiaries.

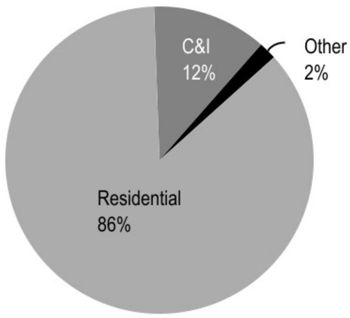
Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities across all four operating companies. Xcel Energy had electric sales volume of 115,474 (millions of KWh), 3.7 million customers and electric revenues of $11,205 (millions of dollars) for 2021.

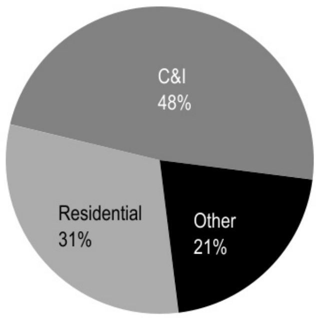
Sales Volume



Number of Customers



Revenues

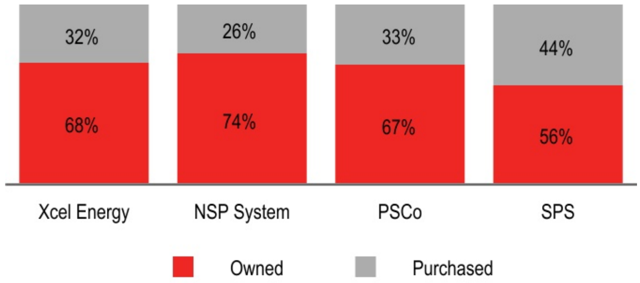


Retail Sales/Revenue Statistics [(a)]

	2021	2020
KWh sales per retail customer	23,968	23,910
Revenue per retail customer	$ 2,405	$ 2,199
Residential revenue per KWh	12.94 ¢	12.12 ¢
Large C&I revenue per KWh	6.60 ¢	5.78 ¢
Small C&I revenue per KWh	10.47 ¢	9.56 ¢
Total retail revenue per KWh	10.03 ¢	9.20 ¢

(a) See Note 6 to the consolidated financial statements for further information.

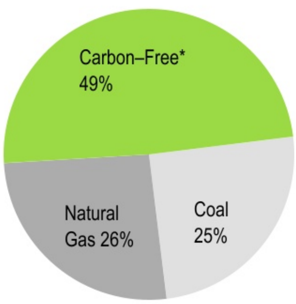
Owned and Purchased Energy Generation — 2021



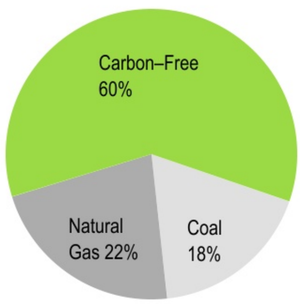
Electric Energy Sources

Total electric energy generation by source (including energy market purchases) for the year ended Dec. 31, 2021:

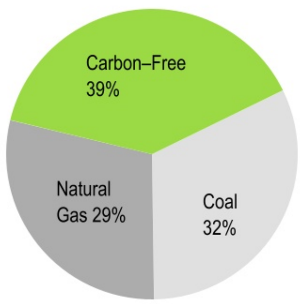
Xcel Energy



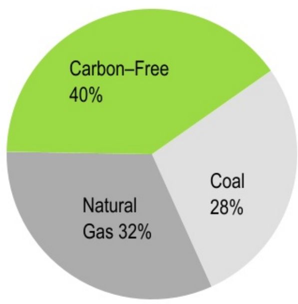
NSP System



PSCo



SPS



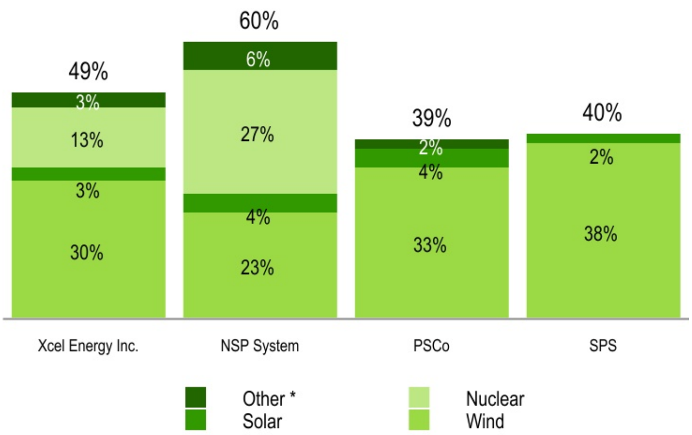
* Distributed generation from the Solar*Rewards® program is not included (approximately 666 million KWh for 2021).

Carbon-Free

Xcel Energy's carbon-free energy portfolio includes wind, nuclear, hydroelectric, biomass and solar power from both owned generation facilities and PPAs. Carbon-free percentages will vary year-over-year based on system additions, commodity costs, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Carbon-free energy as a percentage of total energy for 2021:



* Includes biomass and hydroelectric.

Wind

Owned — Owned and operated wind farms with corresponding capacity:

	2021		2020	
Utility Subsidiary	Wind Farms	Capacity (MW) [a]	Wind Farms	Capacity (MW) [b]
NSP System	14	2,031	11	1,540
PSCo	2	1,059	2	1,059
SPS	2	984	2	967
Total	18	4,075	15	3,566

[a] Summer 2021 net dependable capacity.
[b] Summer 2020 net dependable capacity.

PPAs — Number of PPAs with capacity range:

	2021		2020	
Utility Subsidiary	PPAs	Range (MW)	PPAs	Range (MW)
NSP System	128	1 — 206	129	1 — 206
PSCo	17	23 — 301	17	23 — 301
SPS	17	1 — 250	18	1 — 250

Capacity — Wind capacity (MW):

Utility Subsidiary	2021	2020
NSP System	3,997	3,348
PSCo	4,085	4,085
SPS	2,548	2,535

Average Cost (Owned) — Average cost per MWh of wind energy from owned generation:

Utility Subsidiary	2021	2020
NSP System	$ 25	$ 23
PSCo	17	35
SPS	17	17

Average Cost (PPAs) — Average cost per MWh of wind energy under existing PPAs:

Utility Subsidiary	2021	2020
NSP System	$ 37	$ 38
PSCo	35	40
SPS	27	26

Wind Development

Xcel Energy placed approximately 500 MW of owned wind and approximately 255 MW of PPAs into service during 2021:

Project	Utility Subsidiary	Capacity (MW)
Blazing Star 2	NSP-Minnesota	200 [a][b]
Freeborn	NSP-Minnesota	200 [a][b]
Mower	NSP-Minnesota	91 [a][b]
Various PPAs	Various	~255 [c]

[a] Summer 2021 net dependable capacity.
[b] Values disclosed are the maximum generation levels. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
[c] Based on contracted capacity.

Xcel Energy currently has approximately 1,050 MW of owned wind under development or being repowered. In addition, we expect to add approximately 200 MW of planned PPAs.

Project	Utility Subsidiary	Capacity (MW)	Estimated Completion
Northern Wind	NSP-Minnesota	100	2022
Nobles	NSP-Minnesota	200	2022
Dakota Range	NSP-Minnesota	300	2022 [a]
Grand Meadow	NSP-Minnesota	100	2023
Border Winds	NSP-Minnesota	150	2025
Pleasant Valley	NSP-Minnesota	200	2025
Various PPAs	Various	~200	2022

[a] Placed in service in January 2022.

Solar

Solar PPA(s):

Type	Utility Subsidiary	Capacity (MW)
Distributed Generation	NSP System	994
Utility-Scale	NSP System	268
Distributed Generation	PSCo	736
Utility-Scale	PSCo	562
Distributed Generation	SPS	15
Utility-Scale	SPS	192
Total		2,767

Average Cost (PPAs) — Average cost per MWh of solar energy under existing PPAs:

Utility Subsidiary	2021	2020
NSP System	$ 90	$ 90
PSCo	67	89
SPS	61	59

Solar Development

In June 2021, the PSCW approved NSP-Wisconsin's request to purchase the 74 MW Western Mustang build-own-transfer solar facility for approximately $100 million. Also, as part of the Minnesota Recovery and Relief Recovery docket, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an incremental investment of approximately $575 million. An MPUC decision is expected by the third quarter of 2022.

PSCo placed approximately 260 MW of PPAs into service during 2021.

Nuclear

Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2021 net summer dependable capacity that serves the NSP System. Our nuclear fleet has become one of the best performing and dependable in the nation, as rated by both the NRC and INPO. Xcel Energy secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. We use varying contract lengths as well as multiple producers for uranium concentrates, conversion services and enrichment services to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

Nuclear Fuel Cost

Delivered cost per MMBtu of nuclear fuel consumed for owned electric generation and the percentage of total fuel requirements:

Utility Subsidiary	Nuclear	
NSP System	**Cost**	**Percent**
2021	$ 0.77	46 %
2020	0.80	51

Other

Xcel Energy's other carbon-free energy portfolio includes hydro from owned generating facilities.

See Item 2 — Properties for further information.

Fossil Fuel

Xcel Energy's fossil fuel energy portfolio includes coal and natural gas power from both owned generating facilities and PPAs.

Coal

Xcel Energy owns and operates coal units with approximately 6,500 MW of total 2021 net summer dependable capacity.

Approved early coal plant retirements:

Year	Utility Subsidiary	Plant Unit	Capacity (MW)
2022	PSCo	Comanche 1	325
2023	NSP-Minnesota	Sherco 2	682
2024	SPS	Harrington [(a)]	1,018
2025	PSCo	Comanche 2	335
2025	PSCo	Craig 1	42 [(b)]
2026	NSP-Minnesota	Sherco 1	680
2028	PSCo	Craig 2	40 [(b)]
2028	NSP-Minnesota	A.S. King	511
2030	NSP-Minnesota	Sherco 3	517 [(b)]

(a) Reflects expected conversion from coal to natural gas following the TCEQ order that Harrington cease use of coal fuel by Jan. 1, 2025, pending PUCT and NMPRC review.
(b) Based on Xcel Energy's ownership interest.

Proposed			
Year	**Utility Subsidiary**	**Plant Unit**	**Capacity (MW)**
2025	PSCo	Pawnee [(a)]	505
2027	PSCo	Hayden 2	98 [(b)]
2028	PSCo	Hayden 1	135 [(c)]
2034	SPS	Tolk 1	532
2034	SPS	Tolk 2	535
2034	PSCo	Comanche 3	500 [(d)]

(a) Reflects conversion from coal to natural gas.
(b) Based on PSCo's ownership of 37% of Unit 2.
(c) Based on PSCo's ownership of 76% of Unit 1.
(d) Based on PSCo's ownership of 67%.

Coal Fuel Cost

Delivered cost per MMBtu of coal consumed for owned electric generation and the percentage of fuel requirements:

	Coal [(a)]	
Utility Subsidiary	**Cost**	**Percent**
NSP System		
2021	$ 1.60	39 %
2020	1.97	31
PSCo		
2021	1.43	62
2020	1.41	51
SPS		
2021	2.07	66
2020	2.28	40

(a) Includes refuse-derived fuel and wood for the NSP System.

Natural Gas

Xcel Energy has 22 natural gas plants with approximately 7,900 MW of total 2021 net summer dependable capacity.

Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Natural Gas Cost

Delivered cost per MMBtu of natural gas consumed for owned electric generation and the percentage of total fuel requirements:

	Natural Gas	
Utility Subsidiary	**Cost**	**Percent**
NSP System		
2021 [(a)]	$ 4.98	15 %
2020	2.67	17
PSCo		
2021 [(a)]	8.38	38
2020	3.01	49
SPS		
2021 [(a)]	6.72	34
2020	1.43	60

(a) Reflective of Winter Storm Uri.

Capacity and Demand

Uninterrupted system peak demand and occurrence date for the regulated utilities:

	System Peak Demand (MW)			
	2021		2020	
NSP System	8,837	June 9	8,571	July 8
PSCo	6,958	July 28	6,899	Aug. 17
SPS	4,054	Aug. 9	4,195	July 14

Transmission

Transmission lines deliver electricity at high voltages and over long distances from power sources to transmission substations closer to customers. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy. Xcel Energy owns more than 111,000 conductor miles of transmission lines, serving 22,000 MW of customer load, across its service territory.

Transmission projects completed in 2021 include:

Project	Utility Subsidiary	Miles	Size (KV)
Hibbing Taconite Relocation	NSP-Minnesota	3	500
Huntley - Wilmarth	NSP-Minnesota	50	345
Helena Scott County	NSP-Minnesota	16	345
Centerville to Lincoln County	NSP-Minnesota	14	69
Turtle Lake Almena	NSP-Wisconsin	4	69
Roadrunner-China Draw	SPS	41	345

Notable upcoming projects:

Project	Utility Subsidiary	Miles	Size (KV)	Completion Date
Baytown to Long Lake	NSP-Minnesota	9	115	2022
Bird Island - Atwater - Big Swan	NSP-Minnesota	68	69	2022
Pipestone - Tracy	NSP-Minnesota	46	69	2022
Line Rebuild - Central	NSP-Minnesota	24	69	2022
West St. Cloud to Millwood Tap	NSP-Minnesota	24	69	2022
Bayfield Second Circuit	NSP-Wisconsin	19	35	2022
Colorado Energy Plan	PSCo	15	345	2022
Tolk Plant Substation				
Bus Reconfiguration	SPS	n/a	345, 230	2022
Twist to Wilco Line	SPS	4	115	2024
Pathway	PSCo	560	345	2027

See Item 2 - Properties for further information.

Distribution

Distribution lines allow electricity to travel at lower voltages from substations directly to customers. Xcel Energy has a vast distribution network, owning and operating approximately 210,000 conductor miles of distribution lines across our eight-state service territory.

To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure. Over the multi-year project that started in 2016, Xcel Energy plans to invest approximately $1.7 billion implementing new network infrastructure, smart meters, advanced software, equipment sensors and related data analytics capabilities. To date, Xcel Energy has spent approximately $568 million on these investments.

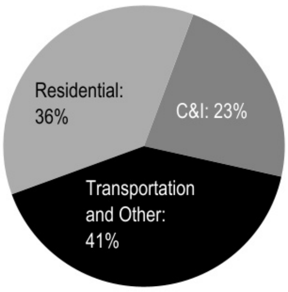
Investments of this nature will further improve reliability and reduce outage restoration times for our customers, while at the same time enabling new options and opportunities for increased efficiency savings. The new capabilities will also enable integration of battery storage and other distributed energy resources into the grid, including electric vehicles.

See Item 2 - Properties for further information.

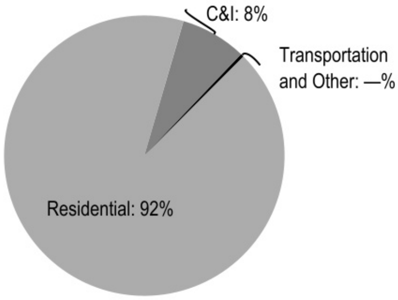
Natural Gas Operations

Natural gas operations consist of purchase, transportation and distribution of natural gas to end-use residential, C&I and transport customers in NSP-Minnesota, NSP-Wisconsin and PSCo. Xcel Energy had natural gas deliveries of 405,895 (thousands of MMBtu), 2.1 million customers and natural gas revenues of $2,132 (millions of dollars) for 2021.

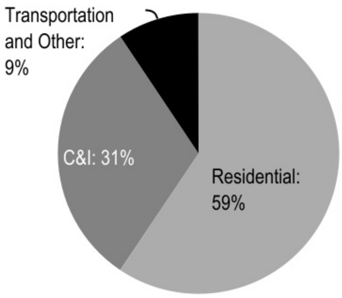
Deliveries



Number of Customers



Revenues



Sales/Revenue Statistics [(a)]

	2021	2020
MMBtu sales per retail customer	114	118
Revenue per retail customer	$ 917	$ 720
Residential revenue per MMBtu	8.61	6.64
C&I revenue per MMBtu	7.20	5.22
Transportation and other revenue per MMBtu	1.20	0.67

(a) See Note 6 to the consolidated financial statements for further information.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply).

Maximum daily output (firm and interruptible) and occurrence date:

	2021		2020	
Utility Subsidiary	MMBtu	Date [(a)]	MMBtu	Date
NSP-Minnesota	899,133	Feb. 11	871,921	Jan. 16
NSP-Wisconsin	167,656	Feb. 11	150,320	Dec. 24
PSCo	2,316,283	Feb. 14	1,931,888	Feb. 4

(a) Reflective of Winter Storm Uri.

Natural Gas Supply and Cost

Xcel Energy seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which increase flexibility, decrease interruption, financial risks and customer rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their states' commissions.

Average delivered cost per MMBtu of natural gas for regulated retail distribution:

Utility Subsidiary	2021 [(a)]	2020
NSP-Minnesota	$ 7.48	$ 3.32
NSP-Wisconsin	7.11	3.08
PSCo	6.06	2.52

(a) Reflective of Winter Storm Uri.

NSP-Minnesota, NSP-Wisconsin and PSCo have natural gas supply transportation and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery.

General

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Management cannot predict the impact of fluctuating energy prices, pandemics, terrorist activity, war or the threat of war. We could experience a material impact to our results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates or inflation.

Seasonality

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

Competition

Xcel Energy is subject to public policies that promote competition and development of energy markets. Xcel Energy's industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them.

Several states have incentives for the development of rooftop solar, community solar gardens and other distributed energy resources. Distributed generating resources are potential competitors to Xcel Energy’s electric service business with these incentives and federal tax subsidies.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. Xcel Energy’s wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load.

FERC Order No. 1000 established competition for ownership of certain new electric transmission facilities under Federal regulations. Some states have state laws that allow the incumbent a Right of First Refusal to own these transmission facilities.

FERC Order 2222 requires that RTO and ISO markets allow participation of aggregations of distributed energy resources. This order is expected to incentivize distributed energy resource adoption, however implementation is expected to vary by RTO/ISO and the near, medium, and long-term impacts of Order 2222 remain unclear.

Xcel Energy Inc.’s utility subsidiaries have franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power or gas, such as municipalization.

While each utility subsidiary faces these challenges, Xcel Energy believes their rates and services are competitive with alternatives currently available.

Governmental Regulations

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid and hazardous wastes or substances. Certain Xcel Energy activities require registrations, permits, licenses, inspections and approvals from these agencies.

Xcel Energy has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities strive to operate in compliance with applicable environmental standards and related monitoring and reporting requirements.

However, it is not possible to determine what additional facilities or modifications of existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of MGP and other sites.

Xcel Energy must comply with emission levels in Minnesota, Texas and Wisconsin that may require the purchase of emission allowances. The Denver North Front Range Non-attainment Area does not meet the ozone NAAQS. Colorado will continue to consider further reductions available in the non-attainment area as it develops plans to meet ozone standards. Natural gas plants which operate in PSCo’s non-attainment area may be required to improve or add controls, implement further work practices and/or enhanced emissions monitoring as part of future Colorado state plans.

There are significant environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. We have undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Future environmental regulations may result in substantial costs.

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for GHG reductions from coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision would allow the EPA to proceed with alternate regulation of coal-fired power plants. However, the Court of Appeals decision is now before the U.S. Supreme Court, where the Court is expected to rule on the nature and extent of the EPA’s GHG regulatory authority. If any new rules require additional investment, Xcel Energy believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

In October 2020, the TCEQ approved an agreement that SPS will convert the Harrington plant from coal to natural gas by Jan. 1, 2025. This conversion is necessary to attain Federal Clean Air Act standards for emissions of SO_2.

Xcel Energy seeks to address climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner.

Emerging Environmental Regulation

New regulations and legislation are being considered to regulate PFAS in drinking water, water discharges, commercial products, wastes, and other areas. PFAS are man-made chemicals found in many consumer products that can persist and accumulate in the environment. These chemicals have received heightened attention from environmental regulators. Increased regulation of PFAS and other emerging contaminants at the federal, state, and local level could have a potential adverse effect on our operations but at this time, it is uncertain what impact, if any, there will be on our operations, financial condition or cash flows. Xcel Energy will continue to monitor these regulatory developments and their potential impact on its operations.

Environmental Costs

Environmental costs include amounts for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions.

Costs charged to operating expenses for nuclear decommissioning, spent nuclear fuel disposal, environmental monitoring and remediation and disposal of hazardous materials and waste were approximately:

- $365 million in 2021.
- $400 million in 2020.
- $345 million in 2019.

Average annual expense of approximately $425 million from 2022 – 2026 is estimated for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements were approximately:

- $60 million in 2021.
- $30 million in 2020.
- $30 million in 2019.

Other

Our operations are subject to workplace safety standards under the Federal Occupational Safety and Health Act of 1970 ("OSHA") and comparable state laws that regulate the protection of worker health and safety. In addition, the Company is subject to other government regulations impacting such matters as labor, competition, data privacy, etc. Based on information to date and because our policies and business practices are designed to comply with all applicable laws, we do not believe the effects of compliance on our operations, financial condition or cash flows are material.

Capital Spending and Financing

See Item 7 for discussion of capital expenditures and funding sources.

Executive Officers [(a)]

Name	Age [(b)]	Current and Recent Positions	Time in Position
Robert C. Frenzel	51	Chairman of the Board of Directors, Xcel Energy Inc.	December 2021 — Present
		President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2021 — Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	August 2021 — Present
		President and Chief Operating Officer, Xcel Energy Inc.	March 2020 — August 2021
		Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 — March 2020
		Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. [(c)]	February 2012 — April 2016
Brett C. Carter [(d)]	55	Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 — Present
		Senior Vice President and Shared Services Executive, Bank of America, an institutional investment bank and financial services company	October 2015 — May 2018
Patricia Correa	48	Senior Vice President, Chief Human Resources Officer, Xcel Energy Inc.	February 2022 — Present
		Senior Vice President, Human Resources, Eaton Corporation, a power management company	July 2019 — January 2022
		Vice President, Human Resources, Eaton Corporation	March 2016 — July 2019
		Senior Director, Talent & Organization Development, Kellogg Company, a food manufacturing company	July 2015 — March 2016
Timothy O'Connor	62	Executive Vice President, Chief Operations Officer, Xcel Energy Inc.	August 2021 — Present
		Executive Vice President, Chief Generation Officer, Xcel Energy Inc.	March 2020 — August 2021
		Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc	February 2013 — March 2020
Frank Prager	59	Senior Vice President, Strategy, Planning and External Affairs, Xcel Energy Inc.	March 2020 — Present
		Vice President, Policy and Federal Affairs, Xcel Energy Services Inc.	January 2015 — March 2020
Amanda Rome	41	Executive Vice President, General Counsel, Xcel Energy Inc.	June 2020 — Present
		Vice President and Deputy General Counsel, Xcel Energy Services Inc.	October 2019 — June 2020
		Managing Attorney, Xcel Energy Services Inc.	July 2018 — October 2019
		Rotational Position, Xcel Energy Services Inc.	January 2018 — July 2018
		Lead Assistant General Counsel, Xcel Energy Services Inc.	July 2015 — January 2018
Jeffrey S. Savage [(e)]	50	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 — Present
Brian J. Van Abel	40	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	March 2020 — Present
		Senior Vice President, Finance and Corporate Development, Xcel Energy Services Inc.	September 2018 — March 2020
		Vice President, Treasurer, Xcel Energy Services Inc.	July 2015 — September 2018

(a) No family relationships exist between any of the executive officers or directors.
(b) Ages as of Feb. 23, 2022.
(c) In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including Texas Competitive Energy Holdings the parent company of Luminant, filed a voluntary bankruptcy petition under Chapter 11 of the United States Bankruptcy Code. Texas Competitive Energy Holdings emerged from Chapter 11 in October 2016.
(d) Effective March 1, 2022, Mr. Carter will assume the role of Executive Vice President, Group President, Utilities, and Chief Customer Officer.
(e) Effective March 1, 2022, Mr. Savage will assume the role of Chief Audit and Financial Services Officer and will no longer be serving as an executive officer.

ITEM 1A — RISK FACTORS

Xcel Energy is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. These risks should be carefully considered together with the other information set forth in this report and future reports that we file with the SEC. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized.

While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Oversight of Risk and Related Processes

The Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors' committees have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors.

Xcel Energy maintains a robust compliance program and promotes a culture of compliance beginning with the tone at the top. The risk mitigation process includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management. Xcel Energy further mitigates inherent risks through formal risk committees and corporate functions such as internal audit, and internal controls over financial reporting and legal.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and risk analysis occurs formally through risk assessment conducted by senior management, the financial disclosure process, hazard risk procedures, internal audit and compliance with financial and operational controls.

Management also identifies and analyzes risk through the business planning process, development of goals and establishment of key performance indicators, including identification of barriers to implementing Xcel Energy's strategy. The business planning process also identifies likelihood and mitigating factors to prevent the assumption of inappropriate risk to meet goals.

Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors, providing information on the risks that management believes are material, including financial impact, timing, likelihood and mitigating factors. The Board of Directors regularly reviews management's key risk assessments, which includes areas of existing and future macroeconomic, financial, operational, policy, environmental and security risks.

The oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors' governance of Xcel Energy. The Board of Directors assigns oversight of critical risks to each of its four committees to ensure these risks are well understood and given appropriate focus.

The Audit Committee is responsible for reviewing the adequacy of the committee's risk oversight and affirming appropriate aggregate oversight occurs. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board of Directors for consideration when deemed appropriate.

New risks are considered and assigned as appropriate during the annual Board of Directors and committee evaluation process, resulting in updates to the committee charters and annual work plans. Additionally, the Board of Directors conducts an annual strategy session where Xcel Energy's future plans and initiatives are reviewed.

Operational Risks

Our natural gas and electric generation/transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages.

These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses to employees, third-party contractors, customers or the public. We maintain insurance against most, but not all, of these risks and losses.

The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows as well as potential loss of reputation.

Other uncertainties and risks inherent in operating and maintaining Xcel Energy's facilities include, but are not limited to:

- Risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned.
- Failures in the availability, acquisition or transportation of fuel or other necessary supplies.
- The impact of unusual or adverse weather conditions and natural disasters, including, but not limited to, tornadoes, icing events, floods and droughts.
- Performance below expected or contracted levels of output or efficiency (e.g., performance guarantees).
- Availability of replacement equipment.
- Availability of adequate water resources and ability to satisfy water intake and discharge requirements.
- Inability to identify, manage properly or mitigate equipment defects.
- Use of new or unproven technology.
- Risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation and lack of available alternative fuel sources.
- Increased competition due to, among other factors, new facilities, excess supply, shifting demand and regulatory changes.

Additionally, compliance with existing and potential new regulations related to the operation and maintenance of our natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with these regulations and systematically monitor and renew infrastructure over time, however, a significant incident or material finding of non-compliance could result in penalties and higher costs of operations.

Our natural gas and electric transmission and distribution operations are dependent upon complex information technology systems and network infrastructure, the failure of which could disrupt our normal business operations, which could have a material adverse effect on our ability to process transactions and provide services.

Our utility operations are subject to long-term planning and project risks.

Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of in-service dates and typically subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. Xcel Energy's long-term resource plan is dependent on our ability to obtain required approvals, develop necessary technical expertise, allocate and coordinate sufficient resources and adhere to budgets and timelines.

In addition, the long-term nature of both our planning and our asset lives are subject to risk. The electric utility sector is undergoing significant change (e.g., increases in energy efficiency, wider adoption of distributed generation and shifts away from fossil fuel generation to renewable generation). Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, and potentially stranded costs if we are not able to fully recover costs and investments.

The magnitude and timing of resource additions and changes in customer demand may not coincide with evolving customer preference for generation resources and end-uses, which introduces further uncertainty into long-term planning. Efforts to electrify the transportation and building sectors to reduce GHG emissions may result in higher electric demand and lower natural gas demand over time. Higher electric demand may require us to adopt new technologies and make significant transmission and distribution investments including advanced grid infrastructure, which increases exposure to overall grid instability and technology obsolescence. Evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may impact our resource mix and put pressure on our ability to recover capital investments in natural gas generation and delivery. Multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We are subject to longer-term availability of inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

Our utilities are highly dependent on suppliers to deliver components in accordance with short and long-term project schedules.

Our products contain components that are globally sourced from suppliers who, in turn, source components from their suppliers. A shortage of key components in which an alternative supplier is not identified could significantly impact project plans. Such impacts could include timing of projects, including potential for project cancellation. Failure to adhere to project budgets and timelines could adversely impact our results of operations, financial condition or cash flows.

We are subject to commodity risks and other risks associated with energy markets and energy production.

In the event fuel costs increase, customer demand could decline and bad debt expense may rise, which may have a material impact on our results of operations. Despite existing fuel recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows and liquidity.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs and supply shortages may not be fully resolved, which could cause disruptions in our ability to provide services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process. Also, significantly higher energy or fuel costs relative to sales commitments could negatively impact our cash flows and results of operations.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk.

Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability. The management of risks associated with hedging and trading is based, in part, on programs and procedures which utilize historical prices and trends.

Due to the inherent uncertainty involved in price movements and potential deviation from historical pricing, Xcel Energy is unable to fully assure that its risk management programs and procedures would be effective to protect against all significant adverse market deviations.

In addition, Xcel Energy cannot fully assure that its controls will be effective against all potential risks, including, without limitation, employee misconduct. If such programs and procedures are not effective, Xcel Energy's results of operations, financial condition or cash flows could be materially impacted.

Failure to attract and retain a qualified workforce could have an adverse effect on operations.

In 2021, the competition for talent has become increasingly intense as a result of the ongoing "great resignation", and we may experience increased employee turnover due to this tightening labor market. In addition, specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets, which may pose additional difficulty for us as we work to recruit, retain and motivate employees in this climate. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

Our operations use third-party contractors in addition to employees to perform periodic and ongoing work.

We rely on third-party contractors to perform operations, maintenance and construction work. Our contractual arrangements with these contractors typically include performance standards, progress payments, insurance requirements and security for performance. Poor vendor performance or contractor unavailability could impact ongoing operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

Our employees, directors, third-party contractors, or suppliers may violate or be perceived to violate our Codes of Conduct, which could have an adverse effect on our reputation.

We are exposed to risk of employee or third-party contractor fraud or other misconduct. All employees and members of the Board of Directors are subject to comply with our Code of Conduct and are required to participate in annual training. Additionally, suppliers are subject to comply with our supplier Code of Conduct.

Xcel Energy does not tolerate discrimination, violations of our Code of Conduct or other unacceptable behaviors. However, it is not always possible to identify and deter misconduct by employees and other third-parties, which may result in governmental investigations, other actions or lawsuits. If such actions are taken against us we may suffer loss of reputation and such actions could have a material effect on our financial condition, results of operations and cash flows.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota has two nuclear generation plants, PI and Monticello. Risks of nuclear generation include:

- Hazards associated with the use of radioactive material in energy production, including management, handling, storage and disposal.
- Limitations on insurance available to cover losses that may arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor.
- Technological and financial uncertainties related to the costs of decommissioning nuclear plants may cause our funding obligations to change.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including the ability to impose fines and/or shut down a unit until compliance is achieved. NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the INPO reviews NSP-Minnesota's nuclear operations. Compliance with the INPO's recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If a nuclear incident did occur, it could have a material impact on our results of operations, financial condition or cash flows. Furthermore, non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased industry regulation, which may increase NSP-Minnesota's compliance costs.

Financial Risks

Our profitability depends on the ability of our utility subsidiaries to recover their costs and changes in regulation may impair the ability of our utility subsidiaries to recover costs from their customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services and earning a return on capital investment. Our rates are generally regulated and are based on an analysis of the utility's costs incurred in a test year. The utility subsidiaries are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital.

There can also be no assurance that our regulatory commissions will judge all the costs of our utility subsidiaries to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery.

Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair the ability of our utility subsidiaries to recover costs historically collected from customers, or these subsidiaries could exceed caps on capital costs required by commissions and result in less than full recovery.

Changes in the long-term cost-effectiveness or to the operating conditions of our assets may result in early retirements of utility facilities. While regulation typically provides cost recovery relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

Higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on common stock.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that our current credit ratings or our subsidiaries' ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, use of historic test years, elimination of riders or interim rates, increasing depreciation lives, lower returns on equity, changes to equity ratios and impacts of tax policy may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any credit ratings downgrade could lead to higher borrowing costs or lower proceeds from equity issuances. It could also impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require posting of collateral or settlement if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates or lower proceeds from equity issuances. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

The performance of capital markets impacts the value of assets held in trusts to satisfy future obligations to decommission NSP-Minnesota's nuclear plants and satisfy our defined benefit pension and postretirement benefit plan obligations. These assets are subject to market fluctuations and yield uncertain returns, which may fall below expected returns. A decline in the market value of these assets may increase funding requirements. Additionally, the fair value of the debt securities held in the nuclear decommissioning and/or pension trusts may be impacted by changes in interest rates.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the economy and unemployment rates.

Credit risk also includes the risk that counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

Xcel Energy may have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, (e.g., California Independent System Operator, SPP, PJM Interconnection, LLC, MISO and Electric Reliability Council of Texas), in which any credit losses are socialized to all market participants.

We have additional indirect credit exposure to financial institutions from letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements of these plans. Estimates and assumptions may change. In addition, the Pension Protection Act sets the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year, due to high numbers of retirements or employees leaving, would trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs.

Increasing costs associated with health care plans may adversely affect our results of operations.

Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Health care legislation could also significantly impact our benefit programs and costs.

We must rely on cash from our subsidiaries to make dividend payments.

Investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and ability to service our debt and pay dividends depends upon the operating cash flows of our subsidiaries and their payment of dividends.

Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for dividends on our common stock. In addition, each subsidiary's ability to pay dividends depends on statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets.

If the utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected. Our utility subsidiaries are regulated by state utility commissions, which possess broad powers to ensure that the needs of the utility customers are met. We may be negatively impacted by the actions of state commissions that limit the payment of dividends by our utility subsidiaries.

Federal tax law may significantly impact our business.

Our utility subsidiaries collect estimated federal, state and local tax payments through their regulated rates. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value/availability of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. If tax rates are increased, there could be timing delays before regulated rates provide for recovery of such tax increases in revenues. In addition, certain IRS tax policies, such as tax normalization, may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Xcel Energy's operations are affected by local, national and worldwide economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills, which could lead to additional bad debt expense.

Our utility subsidiaries face competitive factors, which could have an adverse impact on our financial condition, results of operations and cash flows. Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may inhibit our ability to acquire sufficient supplies. We operate in a capital-intensive industry and federal trade policy could significantly impact the cost of materials we use. There may be delays before these additional material costs can be recovered in rates.

We face risks related to health epidemics and other outbreaks, which may have a material effect on our financial condition, results of operations and cash flows.

The global outbreak of COVID-19 continues to impact countries, communities, supply chains and markets. A high degree of uncertainty continues to exist regarding the pandemic; the duration and magnitude of business restrictions (domestically and globally); the potential shortages of employees and third-party contractors due to quarantine policies, vaccination requirements or government restrictions; re-shutdowns, if any, and the level and pace of economic recovery.

Xcel Energy has experienced and may continue to experience sales volatility and shifts between residential and C&I sales as a result of COVID-19. Xcel Energy has a decoupling mechanism in Colorado for residential and non-demand small C&I electric customer classes. In Minnesota, Xcel Energy has historically had a sales true-up mechanism for all electric customer classes which has ended in 2021. We are requesting implementation of a new sales true-up mechanism for 2022 - 2024. These mechanisms mitigate the impact of changes to sales levels as compared to a baseline.

Although the financial impact of the pandemic on our financial results has largely been mitigated, we cannot ultimately predict whether it will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact of the virus on the health of our employees, our supply chain or our ability to recover higher costs associated with managing through the pandemic. The impact of COVID-19 may exacerbate other risks discussed herein, which could have a material effect on us. The situation is evolving and additional impacts may arise.

Operations could be impacted by war, terrorism or other events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows.

The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility.

We also face the risks of possible loss of business due to significant events such as severe storms, severe temperature extremes, wildfires (particularly in Colorado), widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a workforce disruption.

In addition, major catastrophic events throughout the world may disrupt our business. Xcel Energy participates in a global supply chain, which includes materials and components that are globally sourced. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to reliably serve our customers.

A major disruption could result in a significant decrease in revenues and additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

Xcel Energy participates in GridEx, which is the largest grid security exercise in North America. These efforts, led by the NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

A cyber incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals.

Xcel Energy's generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error.

The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. During the normal course of business, we have experienced and expect to continue to experience attempts to compromise our information technology and control systems, network infrastructure and other assets. To date, no cybersecurity incident or attack has had a material impact on our business or results of operation.

Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

Xcel Energy's generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers' operations, could also negatively impact our business.

Our supply chain for procurement of digital equipment and services may expose software or hardware to these risks and could result in a breach or significant costs of remediation. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. Cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including asset failure or unauthorized access to assets or information.

A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations or cash flows.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change may create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. International agreements could additionally lead to future federal or state regulations.

In 2015, the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2º Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5º Celsius.

In April 2021, ahead of the United Nations Climate Change Conference in Glasgow, the Biden Administration committed the U.S. to a Nationally Determined Contribution of 50-52% net GHG emissions reduction economy-wide from 2005 levels. This commitment and other agreements made in Glasgow could result in future additional GHG reductions in the United States. In addition, the Biden Administration has announced plans to implement new climate change programs, including potential regulation of GHG emissions targeting the utility industry.

Many states and localities continue to pursue their own climate policies. The steps Xcel Energy has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation or retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties.

In the event of serious incidents, these agencies may pursue penalties. In addition, certain states have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

The continued use of natural gas for both power generation and gas distribution have increasingly become a public policy advocacy target. These efforts may result in a limitation of natural gas as an energy source for both power generation and heating, which could impact our ability to reliably and affordably serve our customers.

In recent years, there have been various local and state agency proposals within and outside our service territories that would attempt to restrict the use and availability of natural gas. If such policies were to prevail, we may be forced to make new resource investment decisions which could potentially result in stranded costs if we are not able to fully recover costs and investments and impact the overall reliability of our service.

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate sites where our past activities, or the activities of other parties, caused environmental contamination.

Changes in environmental policies and regulations or regulatory decisions may result in early retirements of our generation facilities. While regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or O&M costs incurred to comply with the requirements.

In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events. Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

Climate change may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods.

To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We have committed to a number of long-term climate change goals, which in part are dependent on future technologies not currently in existence. Given the long-term nature of these goals, there is an inherent uncertainty due to internal and external factors regarding our ability to achieve our stated climate change goals. To the extent climate change goals are not met, this could negatively impact our reputation and potentially result in financial risk.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities.

While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows.

Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of power plants and increase the cost for energy. Adverse events may result in increased insurance costs and/or decreased insurance availability. We may not recover all costs related to mitigating these physical and financial risks.

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 2 — PROPERTIES

Virtually all of the utility plant property of the operating companies is subject to the lien of their respective first mortgage bond indentures.

NSP-Minnesota

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]
Steam:			
A.S. King-Bayport, MN, 1 Unit [f]	Coal	1968	511
Sherco-Becker, MN [e]			
Unit 1	Coal	1976	680
Unit 2	Coal	1977	682
Unit 3	Coal	1987	517 [b]
Monticello, MN, 1 Unit	Nuclear	1971	617
PI-Welch, MN			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Various locations, 4 Units	Wood/Refuse	Various	36 [c]
Combustion Turbine:			
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2018	494
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	447
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	252
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454
Various locations, 7 Units	Natural Gas	Various	10
Wind:			
Blazing Star 1-Lincoln County, MN, 100 Units	Wind	2020	200 [d]
Blazing Star 2-Lincoln County, MN, 100 Units	Wind	2021	200 [d]
Border-Rolette County, ND, 75 Units	Wind	2015	148 [d]
Community Wind North-Lincoln County, MN, 12 Units	Wind	2020	26 [d]
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190 [d]
Crowned Ridge 2-Grant County, SD, 88 Units	Wind	2020	192 [d]
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150 [d]
Freeborn-Freeborn County, MN, 100 Units	Wind	2021	200 [d]
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	99 [d]
Jeffers-Cottonwood County, MN, 20 Units	Wind	2020	43 [d]
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99 [d]
Mower-Mower County, MN, 43 Units	Wind	2021	91 [d]
Nobles-Nobles County, MN, 134 Units	Wind	2010	197 [d]
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196 [d]
		Total	8,628

(a) Summer 2021 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(e) A.S. King is expected to be retired early in 2028.
(f) Sherco Unit 1, 2, and 3 are expected to be retired early in 2026, 2023 and 2030, respectively.

NSP-Wisconsin

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]
Steam:			
Bay Front-Ashland, WI, 2 Units	Wood/Natural Gas	1948 - 1956	41
French Island-La Crosse, WI, 2 Units	Wood/Refuse	1940 - 1948	16 [b]
Combustion Turbine:			
French Island-La Crosse, WI, 2 Units	Oil	1974	122
Wheaton-Eau Claire, WI, 5 Units	Natural Gas/Oil	1973	234
Hydro:			
Various locations, 63 Units	Hydro	Various	135
		Total	548

(a) Summer 2021 net dependable capacity.
(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]
Steam:			
Comanche-Pueblo, CO [b]			
Unit 1	Coal	1973	325
Unit 2	Coal	1975	335
Unit 3	Coal	2010	500 [c]
Craig-Craig, CO, 2 Units [d]	Coal	1979 - 1980	82 [e]
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233 [f]
Pawnee-Brush, CO, 1 Unit	Coal	1981	505
Cherokee-Denver, CO, 1 Unit	Natural Gas	1968	310
Combustion Turbine:			
Blue Spruce-Aurora, CO, 2 Units	Natural Gas	2003	264
Cherokee-Denver, CO, 3 Units	Natural Gas	2015	576
Fort St. Vrain-Platteville, CO, 6 Units	Natural Gas	1972 - 2009	973
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580
Various locations, 8 Units	Natural Gas	Various	251
Hydro:			
Cabin Creek-Georgetown, CO			
Pumped Storage, 2 Units	Hydro	1967	210
Various locations, 8 Units	Hydro	Various	25
Wind:			
Rush Creek, CO, 300 units	Wind	2018	582 [g]
Cheyenne Ridge, CO, 229 units	Wind	2020	477 [g]
		Total	6,228

(a) Summer 2021 net dependable capacity.
(b) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in 2022 and 2025, respectively.
(c) Based on PSCo's ownership of 67%.
(d) Craig Unit 1 and 2 are expected to be retired early in 2025 and 2028, respectively.
(e) Based on PSCo's ownership of 10%.
(f) Based on PSCo's ownership of 76% of Unit 1 and 37% of Unit 2.
(g) Values disclosed are the generation levels at the point-of-interconnection. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

SPS

Station, Location and Unit at Dec. 31, 2021	Fuel	Installed	MW [a]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	225
Harrington-Amarillo, TX, 3 Units [b]	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	298
Tolk-Muleshoe, TX, 2 Units [d]	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	207
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units	Wind	2019	477 [c]
Sagamore-Dora, NM, 240 Units	Wind	2020	507 [c]
		Total	5,249

(a) Summer 2021 net dependable capacity.
(b) Harrington is expected to be converted to natural gas by the end of 2024.
(c) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(d) Tolk Unit 1 and 2 are proposed to be retired in 2034.

Electric utility overhead and underground transmission and distribution lines at Dec. 31, 2021:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Transmission				
500 KV	2,915	—	—	—
345 KV	13,570	2,943	4,978	11,688
230 KV	2,300	—	12,141	9,763
161 KV	640	1,778	—	—
138 KV	—	—	92	—
115 KV	8,086	1,818	5,075	14,880
Less than 115 KV	6,644	5,870	1,830	4,423
Total Transmission	34,155	12,409	24,116	40,754
Distribution				
Less than 115 KV	81,406	27,701	78,712	22,651
Total	**115,561**	**40,110**	**102,828**	**63,405**

Electric utility transmission and distribution substations at Dec. 31, 2021:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	354	204	237	458

Natural gas utility mains at Dec. 31, 2021:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	85	3	2,174	20	11
Distribution	10,741	2,526	23,243	—	—

ITEM 3 — LEGAL PROCEEDINGS

Xcel Energy is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's consolidated financial statements. Legal fees are generally expensed as incurred.

See Note 12 to the consolidated financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5 — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

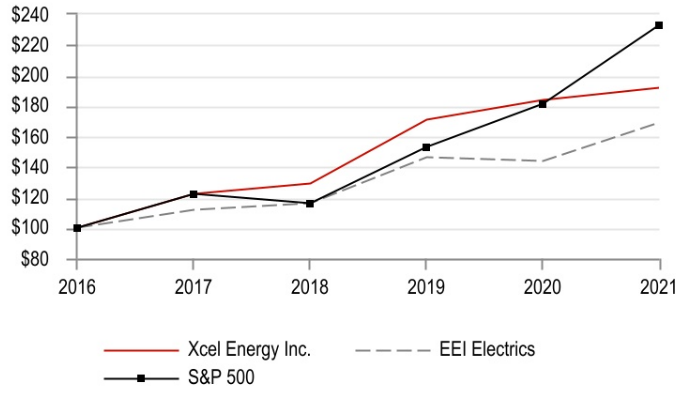
Stock Data

Xcel Energy Inc.'s common stock is listed on the Nasdaq Global Select Market (Nasdaq). The trading symbol is XEL. The number of common stockholders of record as of Feb. 17, 2022 was approximately 49,137.

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the S&P 500 Composite Stock Price Index over the last five years.

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 39 companies at year-end and is a broad measure of industry performance.

Comparison of Five Year Cumulative Total Return*



* $100 invested on Dec. 31, 2016 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2021, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6 — [RESERVED]

ITEM 7 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing 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 excludes (or includes) amounts that are adjusted from 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 is calculated by dividing the net income or loss of each subsidiary, 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 of 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 years ended Dec. 31, 2021 and 2020, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

Diluted Earnings (Loss) Per Share	2021 GAAP and Ongoing Diluted EPS	2020 GAAP and Ongoing Diluted EPS
PSCo	$ 1.22	$ 1.11
NSP-Minnesota	1.12	1.12
SPS	0.59	0.56
NSP-Wisconsin	0.20	0.20
Earnings from equity method investments — WYCO	0.05	0.05
Regulated utility [(a)]	3.18	3.04
Xcel Energy Inc. and Other	(0.22)	(0.25)
Total [(a)]	$ 2.96	$ 2.79

(a) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating Xcel Energy and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, reporting results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

2021 Comparison with 2020

Xcel Energy — GAAP and ongoing earnings increased $0.17 per share for 2021. 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).

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, 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, other regulatory outcomes and higher sales and demand, 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 EIP investments.

Changes in Diluted EPS

Components significantly contributing to changes in EPS:

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

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

ROE for Xcel Energy and its utility subsidiaries:

	2021	2020
ROE	**GAAP and Ongoing ROE**	**GAAP and Ongoing ROE**
NSP-Minnesota	8.45 %	9.20 %
PSCo	8.23	8.06
SPS	9.22	9.54
NSP-Wisconsin	9.92	10.52
Operating Companies	8.58	8.87
Xcel Energy	10.58	10.59

Statement of Income Analysis

The following summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances, the amount of natural gas or electricity historically used per degree of temperature and excludes any incremental related operating expenses that could result due to storm activity or vegetation management requirements. As a result, weather deviations from normal levels can affect Xcel Energy's financial performance. However, sales true-up and decoupling mechanisms in Minnesota and Colorado predominately mitigate the positive and adverse impacts of weather.

Degree-day or THI data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. HDD is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. CDD is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 10, 20 or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates.

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

	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020
HDD	(6.6)%	(3.1)%	(4.3)%
CDD	12.2	22.2	(9.2)
THI	26.8	6.3	20.7

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

	2021 vs. Normal	2020 vs. Normal	2021 vs. 2020
Retail electric	$ 0.096	$ 0.090	$ 0.006
Decoupling and sales true-up	(0.066)	(0.041)	(0.025)
Electric total	$ 0.030	$ 0.049	$ (0.019)
Firm natural gas	(0.025)	(0.011)	(0.014)
Total	$ 0.005	$ 0.038	$ (0.033)

Sales — Sales growth (decline) for actual and weather-normalized sales:

	2021 vs. 2020				
	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)

	2021 vs. 2020				
	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)

	2021 vs. 2020 (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.

Electric Revenues, Fuel and Purchased Power and Electric Margin

(Millions of Dollars)	2021	2020
Electric revenues	$ 11,205	$ 9,802
Electric fuel and purchased power	(4,733)	(3,512)
Electric margin	$ 6,472	$ 6,290

Changes in Electric Margin

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

(a) Includes $27 million of net gains 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.

Natural Gas Revenues, Cost of Natural Gas Sold and Transported and Natural Gas Margin

(Millions of Dollars)	2021	2020
Natural gas revenues	$ 2,132	$ 1,636
Cost of natural gas sold and transported	(1,081)	(689)
Natural gas margin	$ 1,051	$ 947

Changes in Natural Gas Margin

(Millions of Dollars)	2021 vs. 2020
Regulatory rate outcomes (Colorado and North Dakota)	$ 90
Infrastructure and integrity riders	12
Conservation incentive	3
Estimated impact of weather	(10)
Other (net)	9
Increase in natural gas margin	$ 104

Non-Fuel Operating Expenses and Other Items

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 — 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.

Xcel Energy Inc. and Other Results

Net income and diluted EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

	Contribution (Millions of Dollars)	
	2021	2020
Xcel Energy Inc. financing costs	$ (129)	$ (147)
MEC [(a)]	—	15
Venture Holdings [(b)]	21	4
Xcel Energy Inc. taxes and other results	(12)	(5)
Total Xcel Energy Inc. and other costs	$ (120)	$ (133)

	Contribution (Diluted Earnings (Loss) Per Share)	
	2021	2020
Xcel Energy Inc. financing costs	$ (0.24)	$ (0.28)
MEC [(a)]	—	0.03
Venture Holdings [(b)]	0.04	0.01
Xcel Energy Inc. taxes and other results	(0.02)	(0.01)
Total Xcel Energy Inc. and other costs	$ (0.22)	$ (0.25)

(a) MEC was sold in the third quarter of 2020.
(b) Amounts include gains or losses associated with EIP investments.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

2020 Comparison with 2019

A discussion of changes in Xcel Energy's results of operations, cash flows and liquidity and capital resources from the year ended Dec. 31, 2019 to Dec. 31, 2020 can be found in Part II, "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year 2020, which was filed with the SEC on Feb. 17, 2021. However, such discussion is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Public Utility Regulation

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

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

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

See Rate Matters within Note 12 to the consolidated financial statements for further information.

NSP-Minnesota

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
MPUC	Retail rates, services, security issuances, property transfers, mergers, disposition of assets, affiliate transactions, and other aspects of electric and natural gas operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. Certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV in Minnesota. Reviews and approves natural gas supply plans. Pipeline safety compliance.
NDPSC	Retail rates, services and other aspects of electric and natural gas operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota. Pipeline safety compliance.
South Dakota Public Utilities Commission	Retail rates, services and other aspects of electric operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in South Dakota. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce.
MISO	NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and wholesale markets. NSP-Minnesota makes wholesale sales in other RTO markets at market-based rates. NSP-Minnesota and NSP-Wisconsin also make wholesale electric sales at market-based prices to customers outside of their balancing authority as jointly authorized by the FERC.
DOT	Pipeline safety compliance.
Minnesota Office of Pipeline Safety	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
CIP Rider [(a)]	Recovers costs of conservation and DSM programs in Minnesota.
Environmental Improvement Rider	Recovers costs of environmental improvement projects in Minnesota.
Renewable Development Fund	Allocates money collected from customers to support research and development of emerging renewable energy projects and technologies in Minnesota.
RES	Recovers cost of renewable generation in Minnesota.
Renewable Energy Rider	Recovers cost of renewable generation in North Dakota.
State Energy Policy Rider	Recovers costs related to various energy policies approved by the Minnesota legislature.
TCR	Recovers costs for investments in electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation and incremental property taxes in South Dakota.
FCA [(b)]	Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. MISO costs are generally recovered through either the FCA or base rates.
Purchased Gas Adjustment	Provides for prospective monthly rate adjustments for costs of purchased natural gas, transportation and storage service. Includes a true-up process for difference between projected and actual costs.
GUIC Rider	Recovers costs for transmission and distribution pipeline integrity management programs, including funding for pipeline assessments, deferred costs for sewer separation and pipeline integrity management programs in Minnesota.
Sales True-up	In February 2022, NSP-Minnesota filed the 2021 sales true-up compliance report, resulting in a total surcharge of $59 million. An MPUC ruling is anticipated in the second quarter of 2022. In their current rate case, NSP-Minnesota has proposed a sales true-up mechanism for 2022 and beyond that would operate similarly to the 2021 sales true-up. Under the stay-out petition, 2021 NSP-Minnesota jurisdictional earnings was capped at a 9.06% ROE. Any excess earnings are required to be refunded to customers.

(a) Minnesota state law requires NSP-Minnesota to spend 2% of its state electric revenues and 0.5% of its state natural gas revenues on CIP. These costs are recovered through an annual cost-recovery mechanism.

(b) The MPUC changed the FCA process in Minnesota (effective in 2020). Each month, utilities collect amounts equal to baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to baseline costs are tracked and netted over a 12-month period. Utilities issue refunds above the baseline costs and can seek recovery of any overage.

Pending and Recently Concluded Regulatory Proceedings

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

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.
- ALJ Report: March 31, 2023.
- MPUC Order: June 30, 2023.

2021 North Dakota Natural Gas Rate Case — In September 2021, NSP-Minnesota filed a request with the NDPSC for a natural gas rate increase of $7 million, or 10.49%. 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. An 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

2020 North Dakota Electric Rate Case — In November 2020, NSP-Minnesota filed a rate case with the NDPSC seeking a rate increase of $19 million based on a ROE of 10.2%, an equity ratio of 52.5% and rate base of $677 million.

In August 2021, the NDPSC approved a settlement between NSP-Minnesota and various parties, which includes the following, effective Jan. 1, 2021:

- Base revenue increase of $7 million.
- ROE of 9.5%.
- Equity ratio of 52.5%.
- Deferral of advanced grid intelligence and security 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.

Minnesota Relief and Recovery — In 2020, the MPUC opened a docket and invited utilities in the state to submit potential projects that would create jobs and help jump start the economy to offset the impacts of COVID-19.

The status of the various proposals is listed below:

- In January 2021, the MPUC approved NSP-Minnesota's request for the repowering of 651 MW of owned wind projects and 20 MW of wind projects under PPAs. These projects are estimated to save customers approximately $160 million over the next 25 years.
- In April 2021, NSP-Minnesota proposed to add 460 MW of solar facilities at the Sherco site with an incremental investment of approximately $575 million. An MPUC decision is expected by the third quarter of 2022.
- In June 2021, the MPUC approved NSP-Minnesota's proposal to acquire a repowered wind farm from ALLETE, Inc.
- The MPUC is also considering NSP-Minnesota's revised proposal to provide $40 million of incremental electric vehicle rebates.

Minnesota Resource Plan — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034.

On Feb. 8, 2022, the MPUC approved the following:

- 10-year extension for the Monticello nuclear facility.
- Retirement of the A.S. King plant in 2028 and Sherco 3 in 2030.
- NSP-Minnesota ownership of Sherco and A.S. King gen-tie lines plus additional renewable resources on the lines up to its current interconnection rights (2,000 MW for Sherco and 600 MW for A.S. King).
- The need for 2,150 MW of new wind and 2,500 MW of new solar by 2032, as well as additional renewable generation of 1,100 MW beyond 2032.
- Recognition of the need for 800 MW of additional firm dispatchable resources between 2027 and 2029. The dispatchable generation will need to be approved through a CON process.

The next Minnesota resource plan is due on Feb. 1, 2024.

2022 RES Electric Rider — In November 2021, NSP-Minnesota filed the RES Rider. The requested amount of $264 million includes a true-up (2020 and 2021 riders) of $154 million and the 2022 requested amount of $110 million. The filing included a ROE of 9.06%. An MPUC decision is pending.

2021 RES Electric Rider — In November 2020, NSP-Minnesota filed the RES Rider. The requested amount of $189 million includes a true-up (2019 and 2020 riders) of $96 million and the 2021 requested amount of $93 million. The filing included a ROE of 9.06%. An MPUC decision is pending.

2022 GUIC Natural Gas Rider — In October 2021, NSP-Minnesota filed the GUIC Rider for an amount of $27 million based on a ROE of 9.04%. An MPUC decision is pending.

2021 GUIC Natural Gas Rider — In October 2020, NSP-Minnesota filed the GUIC Rider for an amount of $27 million based on a ROE of 9.04%. An MPUC decision is pending.

2022 TCR Electric Rider — In November 2021, NSP-Minnesota filed the TCR Rider for an amount of $105 million based on a ROE of 9.06%. An MPUC decision is pending.

2020 TCR Electric Rider — In November 2019, NSP-Minnesota filed the TCR Rider for an amount of $82 million based on a ROE of 9.06%, which was approved by the MPUC in December 2021.

FERC NOPR on ROE Incentive Adders — In April 2021, the FERC issued a NOPR proposing to limit collection of ROE incentive adders for RTO membership to the first three years after an entity begins participation in an RTO. If adopted as a final rule, NSP-Minnesota (as well as NSP-Wisconsin and SPS) would prospectively discontinue charging their current 50 basis point ROE incentive adders. Amounts related to a discontinuance of the adder would ultimately be offset by an increase in retail rates, subject to future rate cases.

Purchased Power Arrangements and Transmission Service Provider

NSP-Minnesota expects to use power plants, power purchases, CIP/DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a capacity and an energy charge.

NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Nuclear Power Operations

Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes, which are covered by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment contaminated through use.

NRC Regulation — The NRC regulates nuclear operations. Costs of complying with NRC requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs and expects to recover future compliance costs.

Low-Level Waste Disposal — Low level waste disposal from Monticello and PI is disposed at the Clive facility located in Utah and the Waste Control Specialists facility in Texas. NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives if off-site low-level waste disposal facilities become unavailable.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. Currently, there are no definitive plans for a permanent federal storage facility site.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

Monticello CON — In September 2021, NSP-Minnesota filed an application for a CON for additional spent fuel storage (existing independent spent fuel storage installation) at the Monticello Nuclear Power Generating Plant. The CON requests sufficient additional spent fuel storage at the existing independent spent fuel storage installation to allow continued operation of the Monticello Plant until 2040. The filing passed completeness review and has been referred to an ALJ. A decision is expected in late 2023.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and to hedge sales and purchases.

NSP-Minnesota also engages in trading activity unrelated to hedging. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

NSP-Wisconsin

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PSCW	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. The PSCW has a biennial base rate filing requirement. By June of each odd numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January. Pipeline safety compliance.
MPSC	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce.
MISO	NSP-Wisconsin is a transmission owning member of the MISO RTO that operates within the MISO RTO and wholesale energy market. NSP-Wisconsin and NSP-Minnesota are jointly authorized by the FERC to make wholesale electric sales at market-based prices.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
Annual Fuel Cost Plan	NSP-Wisconsin does not have an automatic electric fuel adjustment clause. Under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW. Once the PSCW approves the plan, utilities defer the amount of any fuel cost under-recovery or over-recovery in excess of a 2% annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW. Rate recovery of deferred fuel cost is subject to an earnings test based on the most recently authorized ROE. Under-collections that exceed the 2% annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.
Power Supply Cost Recovery Factors	NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-recoveries are refunded and any under-recoveries are collected from customers.
Wisconsin Energy Efficiency Program	The primary energy efficiency program is funded by the utilities, but operated by independent contractors subject to oversight by the PSCW and utilities. NSP-Wisconsin recovers these costs from customers.
Purchased Gas Adjustment	A retail cost-recovery mechanism to recover the actual cost of natural gas, transportation, and storage services.
Natural Gas Cost-Recovery Factor (MI)	NSP-Wisconsin's natural gas rates for Michigan customers include a natural gas cost-recovery factor, based on 12-month projections and trued-up to actual amounts on an annual basis.

Pending and Recently Concluded Regulatory Proceedings

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.

Michigan Electric Rate Case — In January 2022, NSP-Wisconsin reached an electric rate case settlement in principle with the 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.

Purchased Power and Transmission Services

The NSP System expects to use power plants, power purchases, conservation and DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — Through the Interchange Agreement, NSP-Wisconsin receives power purchased by NSP-Minnesota from other utilities and independent power producers. Long-term purchased power contracts for dispatchable resources typically require a capacity charge and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates.

PSCo

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information on Regulatory Authority
CPUC	Retail rates, accounts, services, issuance of securities and other aspects of electric, natural gas and steam operations. Pipeline safety compliance.
FERC	Wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. Wholesale electric sales at cost-based prices to customers inside PSCo's balancing authority area and at market-based prices to customers outside PSCo's balancing authority area. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.
RTO	PSCo is not presently a member of an RTO and does not operate within an RTO energy market. However, PSCo does make certain sales to other RTO's, including SPP and participates in a joint dispatch agreement with neighboring utilities.
DOT	Pipeline safety compliance.
SPP Western Energy Imbalance Service Market	Balances generation and load regionally and in real time for participants in the Western Interconnection

Recovery Mechanisms

Mechanism	Additional Information
ECA	Recovers fuel and purchased energy costs. Short-term sales margins are shared with customers. The ECA is revised quarterly.
Purchased Capacity Cost Adjustment	Recovers purchased capacity payments.
Steam Cost Adjustment	Recovers fuel costs to operate the steam system. The Steam Cost Adjustment rate is revised quarterly.
DSM Cost Adjustment	Recovers electric and gas DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
RES Adjustment	Recovers the incremental costs of compliance with the RES with a maximum of 1% of the customer's bill.
Colorado Energy Plan Adjustment	Recovers the early retirement costs of Comanche units 1 and 2 to a maximum of 1% of the customer's bill.
Wind Cost Adjustment	Recovers costs for customers who choose renewable resources.
Transmission Cost Adjustment	Recovers costs for transmission investment between rate cases.
Clean Air Clean Jobs Act	Recovers costs associated with the Clean Air Clean Jobs Act.
FCA	PSCo recovers fuel and purchased energy costs from wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay production costs through a forecasted formula rate subject to true-up.
GCA	Recovers costs of purchased natural gas and transportation and is revised quarterly to allow for changes in natural gas rates.
PSIA	Recovers costs for transmission and distribution pipeline integrity management programs.
Decoupling	Mechanism to true-up revenue to a baseline amount for residential (excluding lighting and demand) and metered non-demand small C&I classes.
Transportation Electrification Plan	Recovers costs associated with the investment in and adoption of transportation electrification infrastructure.

Pending and Recently Concluded Regulatory Proceedings

Colorado Natural Gas Rate Case — In January 2022, PSCo filed a request with the CPUC seeking a net increase to retail natural gas rates of $107 million. The total change to base rates is $215 million, reflecting the transfer of $108 million previously recovered from customers through the 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.

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%.

Colorado Electric Rate Request — In July 2021, PSCo filed a request with the 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 is 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 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 Advanced Grid Intelligence and Security 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.

*PSIA Rider Extensio*n — In October 2021, the CPUC approved a settlement agreement to allow the rider to end on Dec. 31, 2021, transfer the investments recovered under the rider to base rates Jan. 1, 2022, and defer $9 million of depreciation expense and return on $143 million in project costs in 2022.

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 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 Integrated Resource Plan with a cost estimate of $247 million.

The settlement agreement is currently being deliberated by the CPUC.

Resource Plan Settlement — In November 2021, PSCo and 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 utility-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.

Partial Settlement — In October 2021, PSCo filed a comprehensive settlement with the CPUC Staff and the COEO, which proposed to address four outstanding regulatory items, including recovery of fuel costs related to Winter Storm Uri, disputed revenue associated with the 2020 electric decoupling pilot program year, replacement power costs associated with an extended outage at Comanche Unit 3 during 2020 and deferred customer bad debt balances associated with COVID-19. The Utility Consumer Advocate has not signed the settlement. A hearing and a CPUC decision on the settlement is expected in the first quarter of 2022.

Key terms of the proposed settlement:

- PSCo would fully recover 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. Recovery would commence Jan. 1, 2022 for electric costs and April 1, 2022 for natural gas costs.
- PSCo will refund electric customers $41 million (previously deferred) related to the 2020 electric decoupling pilot program.
- PSCo agreed to forego recovery of $14 million for replacement power costs due to an extended outage at Comanche Unit 3 during 2020 (approved by the CPUC in February 2022 as part of the 2020 ECA settlement agreement).
- PSCo also agreed to not seek recovery of COVID-19 related bad debt expense, previously deferred as a regulatory asset, and recorded an additional $11 million of incremental bad debt expense for the period ended Dec. 31, 2021.

Decoupling Filing — PSCo's 2019 Electric Rate Case included a decoupling program, effective April 1, 2020 through Dec. 31, 2023. The program applies to Residential and metered small C&I customers who do not pay a demand charge. The program includes a refund and surcharge cap not to exceed 3% of forecasted base rate revenue for a specified period.

In April 2021, PSCo made its annual filing for 2020, and the revised tariff went into effect by operation of law on June 1, 2021. In the annual filing review, the CPUC indicated they may pursue reopening the case in order to revisit the cap. As of Dec. 31, 2021, PSCo has recognized a refund for Residential customers and a surcharge for C&I customers based on 2020 and 2021 results.

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

Comanche Unit 3 — PSCo is part owner and operator of Comanche Unit 3, a 750 MW, coal-fueled electric generating unit. In January 2020, the unit experienced a turbine failure causing the unit to be taken offline for repairs, which were completed in June 2020. During start-up, the unit experienced a loss of turbine oil, which damaged the unit. Comanche Unit 3 recommenced operations in January 2021. Replacement and repair of damaged systems in excess of a $2 million deductible are expected to be recovered through insurance policies. PSCo incurred replacement power costs of approximately $16 million during the outage.

In October 2020, the CPUC initiated a review of Comanche Unit 3's performance. In March 2021, the CPUC Staff issued a report, which noted higher-than average outages and included criticisms of PSCo's operations of Comanche Unit 3 over the last ten years. The report recommended thorough explanation of the future of Comanche Unit 3 operations in the next resource plan, performance standards for all company-owned generation and a review of outage and repair costs in upcoming ECA proceedings.

In October 2021, a comprehensive settlement was reached, which addressed treatment of 2020 Comanche Unit 3 replacement power costs. See Partial Settlement disclosure above for further discussion.

2019 Electric Rate Case Appeal — In August 2020, PSCo filed an appeal with the Denver District Court seeking a review of CPUC decisions on gains and losses on sales of assets, oil and gas royalty revenues, Board of Directors equity compensation and a true-up surcharge to collect the difference between rates from February through August 2020 based on the CPUC's decision on the Company's Application for Reconsideration, Rehearing or Reargument and rates that were actually in place. In January 2022, the Denver District Court issued its decision that the CPUC's approach to gains and losses on certain sales of assets was legally erroneous and confiscatory to PSCo and set aside and remanded the issue for further consideration. The District Court affirmed the CPUC with respect to the remaining decisions.

GCA NOPR — In June 2021, the CPUC issued a NOPR addressing the recovery of costs through the GCA. The proposed rule would establish an annual forecast of GCA costs for each utility and allow each utility to recover only 90%-95% of any costs in excess of the forecasted amount. The proposed rule would allow utilities to earn an incentive equal to an undefined portion of any savings relative to forecasted costs. Comments were filed and requested that the CPUC delay the rule making process until after the 2021 - 2022 heating season; in part because utilities have already proceeded with purchasing gas for the upcoming heating season in accordance with prior CPUC decisions. The CPUC has reopened the GCA NOPR matter and the parties will submit follow-up comments during the first quarter of 2022.

Purchased Power and Transmission Service Providers

PSCo expects to meet its system capacity requirements through electric generating stations, power purchases, new generation facilities, DSM options and expansion of generation plants.

Purchased Power — PSCo purchases power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require capacity and energy charges. It also contracts to purchase power for both wind and solar resources. PSCo makes short-term purchases to meet system load and energy requirements, replace owned generation, meet operating reserve obligations, or obtain energy at a lower cost.

Energy Markets — PSCo plans to join the SPP Western Energy Imbalance Service Market in April 2023. This market is an incremental step in the participation in the organized wholesale market. Energy imbalance markets allow participants to buy and sell power close to the time electricity is consumed and gives system operators real-time visibility across neighboring grids. The result improves balancing supply and demand at a lower cost.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver energy to its customers.

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to hedging. Sharing of any margin is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

SPS

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PUCT	Retail electric operations, rates, services, construction of transmission or generation and other aspects of SPS' electric operations. The municipalities in which SPS operates in Texas have original jurisdiction over rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.
NMPRC	Retail electric operations, retail rates and services and the construction of transmission or generation.
FERC	Wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce.
SPP RTO and SPP Integrated and Wholesale Markets	SPS is a transmission owning member of the SPP RTO and operates within the SPP RTO and SPP integrated and wholesale markets. SPS is authorized to make wholesale electric sales at market-based prices.

Recovery Mechanisms

Mechanism	Additional Information
Distribution Cost Recovery Factor	Recovers distribution costs not included in rates in Texas.
Energy Efficiency Cost Recovery Factor	Recovers costs for energy efficiency programs in Texas.
Energy Efficiency Rider	Recovers costs for energy efficiency programs in New Mexico.
Fuel and Purchased Power Cost Adjustment Clause	Adjusts monthly to recover actual fuel and purchased power costs in New Mexico.
Power Cost Recovery Factor	Allows recovery of purchased power costs not included in Texas rates.
Renewable Portfolio Standards	Recovers deferred costs for renewable energy programs in New Mexico.
TCR Factor	Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in Texas base rates.
Fixed Fuel and Purchased Recovery Factor	Provides for the over- or under-recovery of energy expenses in Texas. Regulations require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis if this condition is expected to continue.
Wholesale Fuel and Purchased Energy Cost Adjustment	SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Pending and Recently Concluded Regulatory Proceedings

2021 New Mexico Electric Rate Case — In January 2021, SPS filed an electric rate case with the 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.

On Feb. 2, 2022, the NMPRC voted 3-2 to reject the uncontested stipulation as filed. The NMPRC then approved a modified settlement, which would maintain the proposed revenue requirement increase of $62 million, but would adjust revenue requirement increase of $62 million, but would adjust the class cost allocation such that all rate classes would have a uniform increase of 4.89%. The NMPRC required the parties to either file their acceptance or opposition to the modified settlement.

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On Feb. 9, 2022, the signatories informed the NMPRC they did not unanimously support the modifications. Accordingly, the Hearing Examiner will issue a procedural order for further proceedings on SPS' originally filed application.

On Feb. 10, 2022, SPS filed a motion requesting the NMPRC either approve the original settlement or approve the modified settlement.

On Feb. 16, 2022, the NMPRC voted to reconsider its order and voted 3-2 to approve the stipulation without modification. New rates will go into effect on Feb. 26, 2022.

2021 Texas Rate Case — In February 2021, SPS filed an electric rate case with the PUCT and its municipalities, seeking an increase in base rates of approximately $140 million. SPS' proposed net rate increase to Texas customers was 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 was 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 included 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).

In January 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.

In February 2022, the ALJ issued an order approving interim rates to be effective on March 1, 2022. A PUCT decision is expected in the first quarter of 2022.

Purchased Power Arrangements and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements.

Purchased Power — SPS purchases power from other utilities and IPPs. Long-term purchased power contracts typically require periodic capacity and energy charges. SPS also makes short-term purchases to meet system load and energy requirements to replace owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers.

Natural Gas

SPS does not provide retail natural gas service, but purchases and transports natural gas for its generation facilities and operates limited natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce and the PHMSA and PUCT for pipeline safety compliance.

Wholesale and Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and to hedge sales and purchases.

Other Public Utility Matters

Comanche Unit 3 Outage

In January 2022, PSCo experienced an incident at the Comanche Unit 3 plant (750 MW, coal-fueled electric generating unit) resulting in damage and an outage that is expected to last approximately two months. PSCo has notified the CPUC and informed them that it will not seek recovery of any replacement power costs above the expected costs if Comanche 3 had been in service. The estimated incremental replacement power costs could be approximately $10 million, assuming a two month outage, normal weather and current market pricing.

Marshall Wildfire

In December 2021, a wildfire ignited in Boulder County, Colorado (the “Marshall Fire”), which burned over 6,000 acres and destroyed or damaged over 1,000 structures. While there were no downed power lines in the ignition area, the determination of the cause of the Marshall Fire is pending.

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

However, in the unlikely event we were found liable, the damages awarded could exceed our coverage and negatively impact our results of operations, financial conditions or cash flows.

Winter Storm Uri

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

Regulatory Overview — Xcel Energy has natural gas, fuel and purchased energy mechanisms in each jurisdiction for recovering incurred costs. However, the utility subsidiaries have deferred February 2021 cost increases for future recovery and sought recovery of the cost increases over a period of up to 63 months to mitigate the impact to customer bills. Additionally, we did not request recovery of financing costs in order to further limit the impact to our customers.

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 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 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 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. An MPUC decision is expected in the summer of 2022. See Rate Matters and Other within Note 12 to the consolidated financial statements for further information.
	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.
NSP-Wisconsin	Wisconsin	In March, the PSCW approved NSP-Wisconsin's proposal to recover $45 million of Winter Storm Uri natural gas costs over nine months through December 2021 with no financing charge.
	Michigan	In May, the MPSC 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 Utility Consumer Advocate recommended disallowances of approximately $131 million. The 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 SPP 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	In March 2021, the NMPRC approved SPS' request to recover $26 million of fuel costs over 24 months with no financing charge, subject to NMPRC review.

Potential Tax Reform

The U.S. Congress is currently discussing potential proposals that may impact federal tax law. At this time, it is unknown what, if any, changes may ultimately occur. Based on provisions passed by the U.S. House of Representatives in November 2021, known as the Build Back Better Act, if any of such provisions were to be enacted into law, we would not expect the impact of such changes to have a material impact on our earnings.

Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements requires the application of accounting rules and guidance, as well as the use of estimates. Application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and results reported.

Accounting policies and estimates that are most significant to Xcel Energy's results of operations, financial condition or cash flows, and require management's most difficult, subjective or complex judgments are outlined below. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy is subject to the accounting for Regulated Operations, which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. Our rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows.

Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or other comprehensive income.

Each reporting period we assess the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital, and may materially impact our results of operations, financial condition or cash flows.

As of Dec. 31, 2021 and 2020, Xcel Energy had regulatory assets of $3.8 billion and $3.4 billion, respectively and regulatory liabilities of $5.7 billion and $5.6 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs in any such jurisdiction is no longer probable, Xcel Energy would be required to charge these assets to current net income or other comprehensive income.

At Dec. 31, 2021, in assessing the probability of recovery of recognized regulatory assets, unless otherwise disclosed, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the recovery of the assets.

See Notes 4 and 12 to the consolidated financial statements for further information.

Income Tax Accruals

Judgment, uncertainty and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR.

Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our future ETR. ETR calculations are revised every quarter based on best available year-end tax assumptions, adjusted in the following year after returns are filed. Tax accrual estimates are trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted annual ETR. The forecasted ETR reflects a number of estimates, including forecasted annual income, permanent tax adjustments and tax credits.

Valuation allowances are applied to deferred tax assets if it is more likely than not that at least a portion may not be realized based on an evaluation of expected future taxable income. Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. We may adjust our unrecognized tax benefits and interest accruals as disputes with the IRS and state tax authorities are resolved, and as new developments occur. These adjustments may increase or decrease earnings.

See Note 7 to the consolidated financial statements for further information.

Employee Benefits

We sponsor several noncontributory, defined benefit pension plans and other postretirement benefit plans that cover almost all employees and certain retirees. Projected benefit costs are based on historical information and actuarial calculations that include key assumptions (annual return level on pension and postretirement health care investment assets, discount rates, mortality rates and health care cost trend rates, etc.). In addition, the pension cost calculation uses a methodology to reduce the volatility of investment performance over time. Pension assumptions are continually reviewed.

At Dec. 31, 2021, Xcel Energy set the rate of return on assets used to measure pension costs at 6.49%, which is consistent with the rate set in 2020. The rate of return used to measure postretirement health care costs is 4.10% at Dec. 31, 2021, which is consistent with the rate set in 2020.

Xcel Energy's pension investment strategy is based on plan-specific investments that seek to minimize investment and interest rate risk as a plan's funded status increases over time. This strategy results in a greater percentage of interest rate sensitive securities being allocated to plans with higher funded status ratios and a greater percentage of growth assets being allocated to plans having lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 3.08% and postretirement health care obligations at 3.09% at Dec. 31, 2021. This represents a 37 basis point and 44 basis point decrease, respectively, from 2020. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration.

The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Merrill Lynch Corporate 15+ Bond Index. In addition, Xcel Energy reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

If Xcel Energy were to use alternative assumptions, a 1% change would result in the following impact on 2021 pension costs:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (13)	$ 23
Discount rate [(a)]	$ 1	$ 15

(a) These costs include the effects of regulation.

Mortality rates are developed from actual and projected plan experience for pension plan and postretirement benefits. Xcel Energy's actuary conducts an experience study periodically to determine an estimate of mortality. Xcel Energy considers standard mortality tables, improvement factors and the plans actual experience when selecting a best estimate.

As of Dec. 31, 2021, the initial medical trend cost claim assumptions for Pre-65 was 5.3% and Post-65 was 4.9%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

Funding contributions in 2021 were $131 million and are expected to decline in the following years. Investment returns exceeded assumed levels in 2021, 2020 and 2019.

The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20% per year. As differences between actual and expected investment returns are incorporated into the market-related value, amounts are recognized in pension cost over the expected average remaining years of service for active employees (approximately 13 years in 2021).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $77 million in 2022 and $60 million in 2023, while the actual pension costs were $121 million in 2021 and $117 million in 2020. The expected decrease in 2022 and future year costs is primarily due to the reductions in loss amortizations.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2019 - 2022:

- $50 million in January 2022.
- $131 million in 2021.
- $150 million in 2020.
- $154 million in 2019.

Future amounts may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

Xcel Energy contributed $15 million, $11 million and $15 million during 2021, 2020 and 2019, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $9 million during 2022. Xcel Energy recovers employee benefits costs in its utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability.
- In 2021, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2021 pension settlement accounting expense. In addition, the Commission order approved escrow accounting treatment for pension and other post-employment benefit expenses.
- Regulatory Commissions in Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on GAAP. The Texas and Colorado electric retail jurisdictions and the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.
- In 2018, PSCo was required to create a regulatory liability to adjust postretirement health care costs to zero in order to match the amounts collected in rates in the Colorado Gas retail jurisdiction. In 2020, this requirement was extended to the Colorado Electric retail jurisdiction.

See Note 11 to the consolidated financial statements for further information.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions, it adjusts the carrying amount of both the ARO liability and related long-lived asset. ARO liabilities are accreted to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The nuclear decommissioning obligation is funded by the external decommissioning trust fund. Difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $2.1 billion in 2021 and $2.0 billion in 2020.

NSP-Minnesota obtains periodic independent cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. Estimates of future cash flows are highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning filing every three years. The filing covers all expenses for the decommissioning of the nuclear plants, including decontamination and removal of radioactive material.

The currently approved triennial filing was ordered by the MPUC in January 2019. This approval did not result in a change to the ARO liability. In December 2020, the MPUC ordered Xcel Energy to maintain the current accrual through 2021 to align with the approved one year stay out of the previously filed multi-year electric rate case. Also, in December 2020, Xcel Energy filed an accrual proposal with the MPUC to be effective in 2022 based on an updated independent cost study. In December 2021, Xcel Energy submitted its petition for approval of the 2022-2024 NSP-Minnesota's Nuclear Decommission Study and Assumptions. Xcel Energy anticipates the MPUC to deliberate on this filing in February 2022.

The following assumptions have a significant effect on the estimated nuclear obligation:

Timing — Decommissioning cost estimates are impacted by each facility's retirement date and timing of the actual decommissioning activities. Estimated retirement dates coincide with the expiration of each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method (required by the MPUC), which assumes prompt removal and dismantlement. Decommissioning activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology, experience and regulations could cause cost estimates to change significantly.

Escalation Rates — Escalation rates represent projected cost increases due to general inflation and increases in the cost of decommissioning activities. NSP-Minnesota used an escalation rate of 3.2% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.

Discount Rates — Changes in timing or estimated cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity.

If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately 3% to 7% have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating future costs including the method to be utilized, ultimate costs to decommission and planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially.

However, changes in estimates have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the assumptions and uncertainties for each area. The information and assumptions of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2021.

See Note 12 to the consolidated financial statements for further information.

Derivatives, Risk Management and Market Risk

We are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

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

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

Commodity Price Risk — We are exposed to commodity price risk in our electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Our risk management policy allows us to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

Wholesale and Commodity Trading Risk — Xcel Energy conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Our risk management policy allows management to conduct these activities within guidelines and limitations as approved by our risk management committee.

Fair value of net commodity trading contracts as of Dec. 31, 2021:

	Futures / Forwards Maturity				
(Millions of Dollars)	**Less Than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**Greater Than 5 Years**	**Total Fair Value**
NSP-Minnesota [a]	$ (4)	$ (7)	$ —	$ (1)	$ (12)
NSP-Minnesota [b]	(1)	3	(9)	(8)	(15)
PSCo [a]	6	6	1	1	14
PSCo [b]	(37)	(48)	—	—	(85)
	$ (36)	$ (46)	$ (8)	$ (8)	$ (98)

	Options Maturity				
(Millions of Dollars)	**Less Than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**Greater Than 5 Years**	**Total Fair Value**
NSP-Minnesota [b]	$ 1	$ —	$ —	$ 8	$ 9
PSCo [b]	27	29	—	—	56
	$ 28	$ 29	$ —	$ 8	$ 65

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

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the years ended Dec. 31:

(Millions of Dollars)	**2021**	**2020**
Fair value of commodity trading net contracts outstanding at Jan. 1	$ (54)	$ (59)
Contracts realized or settled during the period	(54)	(9)
Commodity trading contract additions and changes during the period	75	14
Fair value of commodity trading net contracts outstanding at Dec. 31	$ (33)	$ (54)

At Dec. 31, 2021, a 10% increase in market prices for commodity trading contracts through the forward curve would increase pretax income from continuing operations by approximately $13 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $13 million. At Dec. 31, 2020, a 10% increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $13 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $13 million. Market price movements can exceed 10% under abnormal circumstances.

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

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

(Millions of Dollars)	**Year Ended Dec. 31**	**VaR Limit**	**Average**	**High**	**Low**
2021	$ 1	$ 3	$ 2	$ 52	$ 1
2020	1	3	1	2	1

A short-term increase in VaR occurred during the week of Feb. 12, 2021 through Feb. 18, 2021. On Feb. 17, 2021, the portfolio VaR reached a high of $52 million. This increase in VaR was driven by the unprecedented market conditions during Winter Storm Uri. Prior to this widespread weather event, VaR was $1 million and returned to $1 million by Feb. 19, 2021.

Nuclear Fuel Supply — NSP-Minnesota has contracted for approximately 78% of its 2022 enriched nuclear material requirements from sources that could be impacted by sanctions against entities doing business with Iran. Those sanctions may impact the supply of enriched nuclear material supplied from Russia. Long-term, through 2030, NSP-Minnesota is scheduled to take delivery of approximately 30% of its average enriched nuclear material requirements from these sources. NSP-Minnesota is able to manage nuclear fuel supply with alternate potential sources. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

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

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $11 million and $6 million in 2021 and 2020, respectively.

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

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

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

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

At Dec. 31, 2021, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $36 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $26 million. At Dec. 31, 2020, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $11 million, while a an increase in credit exposure of $11 million, while a decrease in prices of 10% would have resulted in an immaterial increase in credit exposure.

Xcel Energy conducts credit reviews for all counterparties and employs credit risk controls, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored, and when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase our credit risk.

Fair Value Measurements

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

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

Commodity Derivatives — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. The impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2021.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2021.

See Notes 10 and 11 to the consolidated financial statements for further information.

Liquidity and Capital Resources

Cash Flows

Operating Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash provided by operating activities — 2020	$	2,848
Components of change — 2021 vs. 2020		
Higher net income		124
Non-cash transactions [(a)]		52
Changes in working capital [(b)]		(50)
Changes in net regulatory and other assets and liabilities		(785)
Cash provided by operating activities — 2021	$	2,189

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

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

Net cash provided by operating activities decreased by $659 million for 2021 as compared to 2020. The decrease was primarily due to the deferral of net natural gas, fuel and purchased energy costs related to Winter Storm Uri in the first quarter.

Investing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash used in investing activities — 2020	$	(4,740)
Components of change — 2021 vs. 2020		
Decreased capital expenditures		1,125
Sale of MEC in 2020		(684)
Other investing activities		12
Cash used in investing activities — 2021	$	(4,287)

Net cash used in investing activities decreased by $453 million for 2021 as compared to 2020. The decrease in capital expenditures was largely due to the purchase of MEC in January 2020, which was subsequently sold in July 2020, as well as the completion of various wind projects.

Financing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash provided by financing activities — 2020	$	1,773
Components of change — 2021 vs. 2020		
Higher debt issuances		202
Lower repayments of long-term debt		584
Lower proceeds from issuance of common stock		(361)
Higher dividends paid to shareholders		(79)
Other financing activities		16
Cash provided by financing activities — 2021	$	2,135

Net cash provided by financing activities increased by $362 million for 2021 as compared to 2020. The increase was primarily attributable to the amount/timing of debt issuances and repayments, changes in capital investment and incremental financing due to the lag in recovery costs associated with Winter Storm Uri.

See Note 5 to the consolidated financial statements for further information.

Capital Requirements

Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The Company expects to have adequate amounts of cash from operating and/or financing activities to meet both its short-term and long-term cash requirements. Xcel Energy's financing requirements are dependent on both existing contractual obligations and other commitments, as well as projected capital forecasts. Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios. Projected future financing requirements can be impacted by various factors including constraints to supply chain and labor, as well as inflation.

Recovery of the effects of inflation through higher customer rates is dependent upon receiving adequate and timely rate increases. Rate increases may not be retroactive and often lag increases in costs caused by inflation. On occasion, the Company may enter into rate settlement agreements, which require us to wait for a period of time to file the next base rate increase request. These agreements may result in regulatory lag whereby the impact of inflation may not yet be reflected in rates, or a delay may occur between capital project completion and the start of rate recovery. Xcel Energy attempts to mitigate the potential impact of inflation through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances.

Contractual Obligations and Other Commitments

	Payments Due by Period (as of Dec. 31, 2021)				
(Millions of Dollars)	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	After 5 Years
Long-term debt, principal and interest payments	$ 37,014	$ 1,419	$ 3,323	$ 3,175	$ 29,097
Finance lease obligations	242	12	24	19	187
Operating leases obligations [(a)]	1,594	256	478	363	497
Unconditional purchase obligations [(b)]	4,837	1,718	1,538	617	964
Other long-term obligations, including current portion [(c)]	40	36	4	—	—
Other short-term obligations	455	455	—	—	—
Short-term debt	1,005	1,005	—	—	—
Total contractual cash obligations	$ 45,187	$ 4,901	$ 5,367	$ 4,174	$ 30,745

(a) Included in operating lease obligations are $229 million, $430 million, $335 million and $416 million, for the less than 1 year, 1 - 3 years, 3 - 5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

(b) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its fuel (nuclear, natural gas and coal) requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into non-lease purchase power agreements. Certain contractual purchase obligations are adjusted on indices. Effects of price changes are mitigated through cost of energy adjustment mechanisms.

(c) Primarily consists of contracts for information technology services.

Capital Expenditures — Base capital expenditures and incremental capital forecasts:

	Actual	Base Capital Forecast (Millions of Dollars)					
By Regulated Utility	2021	2022	2023	2024	2025	2026	2022 - 2026 Total
PSCo	$ 1,625	$ 1,930	$ 1,850	$ 2,070	$ 2,220	$ 1,860	$ 9,930
NSP-Minnesota	1,885	2,250	2,030	1,830	2,130	2,010	10,250
SPS	555	630	660	690	780	790	3,550
NSP-Wisconsin	290	480	420	540	460	390	2,290
Other [(a)]	25	(10)	—	10	(30)	10	(20)
Total base capital expenditures	$ 4,380	$ 5,280	$ 4,960	$ 5,140	$ 5,560	$ 5,060	$ 26,000

	Actual	Base Capital Forecast (Millions of Dollars)					
By Function	2021	2022	2023	2024	2025	2026	2022 - 2026 Total
Electric distribution	$ 1,110	$ 1,485	$ 1,600	$ 1,520	$ 1,605	$ 1,720	$ 7,930
Electric transmission	830	1,105	1,220	1,575	1,965	1,555	7,420
Electric generation	575	645	580	670	650	650	3,195
Natural gas	655	655	670	695	660	660	3,340
Other	610	725	545	450	340	450	2,510
Renewables	600	665	345	230	340	25	1,605
Total base capital expenditures	$ 4,380	$ 5,280	$ 4,960	$ 5,140	$ 5,560	$ 5,060	$ 26,000

(a) Other category includes intercompany transfers for safe harbor wind turbines.

The five-year capital forecast includes the proposed Colorado Pathway transmission expansion (approximately $1.7 billion) and the proposed 460 MW Sherco solar facility (approximately $600 million).

Additional capital investment in renewable generation and transmission may be needed in the five-year forecast pending approval of regulatory filings in Minnesota and Colorado. The approval of the proposed resource plans could result in up to 2,000 MW of renewable generation being needed between 2024 - 2026, resulting in potential capital expenditures estimated between $1.0 to $1.5 billion (assuming Xcel Energy were to own ~50% of the renewables). Additionally, the associated $0.5 billion to $1.0 billion of network upgrades, voltage support and interconnection work related to the Colorado Power Pathway could also be needed during this five-year forecast depending on resource mix, location and timing. Any additional capital investment would likely be funded with approximately 50% equity and 50% debt.

Xcel Energy's capital expenditure forecast is subject to continuing review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, safety and reliability needs, regulatory decisions, legislative initiatives (e.g., federal clean energy and tax policy), reserve requirements, availability of purchased power, alternative plans for meeting long-term energy needs, environmental initiatives and regulation, and merger, acquisition and divestiture opportunities.

Financing for Capital Expenditures through 2026 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

Current estimated financing plans of Xcel Energy for 2022 through 2026:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from operations [(a)]	$ 17,640
New debt [(b)]	7,110
Equity through the DRIP and benefit program	450
Other equity	800
Base capital expenditures 2021 - 2025	$ 26,000
Maturing Debt	$ 3,900

[(a)] Net of dividends and pension funding.
[(b)] Reflects a combination of short and long-term debt; net of refinancing.

Off-Balance Sheet Arrangements

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

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial condition, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. In February 2022, Xcel Energy announced an increase in the annual dividend of 12 cents per share, which represents an increase of 6.6%.

Xcel Energy's dividend policy balances the following:

- Projected cash generation.
- Projected capital investment.
- A reasonable rate of return on shareholder investment.
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places limits on the ability of public utilities within a holding company to declare dividends. Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants.

See Note 5 to the consolidated financial statements for further information.

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

Funded status and pension assumptions:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Fair value of pension assets	$ 3,670	$ 3,599
Projected pension obligation [(a)]	3,718	3,964
Funded status	$ (48)	$ (365)

[(a)] Excludes non-qualified plan of $43 million and $43 million at Dec. 31, 2021 and 2020, respectively.

Pension Assumptions	2021	2020
Discount rate	3.08 %	2.71 %
Expected long-term rate of return	6.49	6.49

Capital Sources

Short-Term Funding Sources — Xcel Energy generally funds short-term needs, through operating cash flows, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend on construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash and short-term investment accounts.

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

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

Xcel Energy Inc. repaid its $1.2 billion 364-Day Term Loan Agreement in the fourth quarter.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2021
Borrowing limit	$ 3,100
Amount outstanding at period end	1,005
Average amount outstanding	1,200
Maximum amount outstanding	1,774
Weighted average interest rate, computed on a daily basis	0.54 %
Weighted average interest rate at end of period	0.31

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2021	Year Ended Dec. 31, 2020
Borrowing limit	$ 3,100	$ 3,100
Amount outstanding at period end	1,005	584
Average amount outstanding	1,399	1,126
Maximum amount outstanding	2,054	2,080
Weighted average interest rate, computed on a daily basis	0.57 %	1.45 %
Weighted average interest rate at end of period	0.31	0.23

Credit Facility Agreements — Xcel Energy Inc., NSP-Minnesota, PSCo and SPS each have the right to request an extension of the revolving credit facility for two additional one-year periods beyond the June 2024 termination date. NSP-Wisconsin has the right to request an extension of the revolving credit facility for an additional year. All extension requests are subject to majority bank group approval.

As of Feb. 18, 2022, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,250	$ 757	$ 493	$ 2	$ 495
PSCo	700	26	674	22	696
NSP-Minnesota	500	11	489	13	502
SPS	500	235	265	3	268
NSP-Wisconsin	150	—	150	3	153
Total	$ 3,100	$ 1,029	$ 2,071	$ 43	$ 2,114

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

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2021 and 2020, Xcel Energy had approximately 544 million shares and 537 million shares of common stock outstanding, respectively.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC pursuant to which they may sell securities from time to time. These registration statements, which are uncapped, permit Xcel Energy Inc. and its utility subsidiaries to issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings, and in the case of our utility subsidiaries, subject to commission approval.

Planned Financing Activity — Xcel Energy's 2022 financing plans reflect 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.

Equity through DRIP and Benefits Program — Xcel Energy also plans to issue approximately $90 million of equity annually through the DRIP and benefit programs during the five-year forecast time period.

ATM Equity Offering — In November 2021, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $800 million of its common stock through an ATM program. As of Dec. 31, 2021, Xcel Energy Inc. issued 5.33 million shares of common stock with net proceeds of $347 million through the ATM program.

Long-Term Borrowings and Other Financing Instruments — See Note 5 to the consolidated financial statements for further information.

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.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See the "Derivatives, Risk Management and Market Risk" section in Item 7, incorporated by reference.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See Item 15-1 for an index of financial statements included herein.

See Note 15 to the consolidated financial statements for further information.

Management Report on Internal Control Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2021. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework (2013). Based on our assessment, we believe that, as of Dec. 31, 2021, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an attestation report on Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ ROBERT C. FRENZEL	/s/ BRIAN J. VAN ABEL
Robert C. Frenzel	Brian J. Van Abel
Chairman, President, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer
Feb. 23, 2022	Feb. 23, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Xcel Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Assets and Liabilities - Impact of Rate Regulation on the Financial Statements — Refer to Notes 4 and 12 to the consolidated financial statements.

Critical Audit Matter Description

The Company is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota, South Dakota, Wisconsin, Michigan, Colorado, New Mexico, and Texas. The Company is also subject to the jurisdiction of the Federal Energy Regulatory Commission for its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with North American Electric Reliability Corporation standards, asset transactions and mergers and natural gas transactions in interstate commerce, (collectively with state utility regulatory agencies, the “Commissions”). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant and equipment, regulatory assets and liabilities, operating revenues and expenses, and income taxes.

The Company is subject to regulatory rate setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the Company’s costs to provide utility service and a return on, and recovery of, the Company’s investment in assets required to deliver services to customers. Accounting for the Company’s regulated operations provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. The Commissions’ regulation of rates is premised on the full recovery of incurred costs and a reasonable rate of return on invested capital. Decisions by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. In the rate setting process, the Company’s rates result in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant, and 3) a refund due to customers. Given that management’s accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management’s controls over the recognition of regulatory assets or liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company, regulatory statutes, interpretations, procedural schedules and memorandums, filings made by intervenors, experts’ testimony and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions’ treatment of similar costs under similar circumstances. We also evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects. If the full recovery of project costs is being challenged by intervenors, we evaluated management’s assessment of the probability of a disallowance. We evaluated the external information and compared to the Company’s recorded regulatory assets and liabilities for completeness.
- We obtained management’s analysis and correspondence from counsel, as appropriate, regarding regulatory assets or liabilities not yet addressed in a regulatory order to assess management’s assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 23, 2022

We have served as the Company’s auditor since 2002.

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

	Year Ended Dec. 31		
	2021	2020	2019
Operating revenues			
Electric	$ 11,205	$ 9,802	$ 9,575
Natural gas	2,132	1,636	1,868
Other	94	88	86
Total operating revenues	13,431	11,526	11,529
Operating expenses			
Electric fuel and purchased power	4,733	3,512	3,510
Cost of natural gas sold and transported	1,081	689	918
Cost of sales — other	38	37	40
Operating and maintenance expenses	2,321	2,324	2,338
Conservation and demand side management expenses	304	288	285
Depreciation and amortization	2,121	1,948	1,765
Taxes (other than income taxes)	630	612	569
Total operating expenses	11,228	9,410	9,425
Operating income	2,203	2,116	2,104
Other income (expense), net	5	(6)	16
Earnings from equity method investments	62	40	39
Allowance for funds used during construction — equity	73	115	77
Interest charges and financing costs			
Interest charges — includes other financing costs of $29, $28 and $26, respectively	842	840	773
Allowance for funds used during construction — debt	(26)	(42)	(37)
Total interest charges and financing costs	816	798	736
Income before income taxes	1,527	1,467	1,500
Income tax (benefit) expense	(70)	(6)	128
Net income	$ 1,597	$ 1,473	$ 1,372
Weighted average common shares outstanding:			
Basic	539	527	519
Diluted	540	528	520
Earnings per average common share:			
Basic	$ 2.96	$ 2.79	$ 2.64
Diluted	2.96	2.79	2.64

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2021	2020	2019
Net income	$ 1,597	$ 1,473	$ 1,372
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of $—, $(2) and $—, respectively	—	(5)	—
Reclassification of losses to net income, net of tax of $3, $3 and $1, respectively	8	10	3
Derivative instruments:			
Net fair value increase (decrease), net of tax of $1, $(3) and $(8), respectively	4	(10)	(23)
Reclassification of losses to net income, net of tax of $2, $2 and $1, respectively	6	5	3
Total other comprehensive income (loss)	18	—	(17)
Total comprehensive income	$ 1,615	$ 1,473	$ 1,355

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2021	2020	2019
Operating activities			
Net income	$ 1,597	$ 1,473	$ 1,372
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	2,143	1,959	1,785
Nuclear fuel amortization	114	123	119
Deferred income taxes	(79)	(8)	143
Allowance for equity funds used during construction	(73)	(115)	(77)
Earnings from equity method investments	(62)	(40)	(39)
Dividends from equity method investments	42	42	40
Provision for bad debts	60	60	42
Share-based compensation expense	31	73	58
Net realized and unrealized hedging and derivative transactions	(57)	(27)	45
Changes in operating assets and liabilities:			
Accounts receivable	(164)	(154)	(20)
Accrued unbilled revenues	(149)	(3)	42
Inventories	(126)	(80)	(84)
Other current assets	(34)	(45)	25
Accounts payable	138	(33)	(12)
Net regulatory assets and liabilities	(973)	(144)	(66)
Other current liabilities	(1)	29	(15)
Pension and other employee benefit obligations	(135)	(125)	(135)
Other, net	(83)	(137)	40
Net cash provided by operating activities	2,189	2,848	3,263
Investing activities			
Capital/construction expenditures	(4,244)	(5,369)	(4,225)
Sale of MEC	—	684	—
Purchase of investment securities	(757)	(1,398)	(995)
Proceeds from the sale of investment securities	743	1,378	975
Other, net	(29)	(35)	(98)
Net cash used in investing activities	(4,287)	(4,740)	(4,343)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	421	(11)	(443)
Proceeds from issuances of long-term debt	2,710	2,940	2,920
Repayments of long-term debt, including reacquisition premiums	(417)	(1,001)	(949)
Proceeds from issuance of common stock	366	727	458
Dividends paid	(935)	(856)	(791)
Other, net	(10)	(26)	(14)
Net cash provided by financing activities	2,135	1,773	1,181
Net change in cash and cash equivalents	37	(119)	101
Cash, cash equivalents and restricted cash at beginning of period	129	248	147
Cash, cash equivalents and restricted cash at end of period	$ 166	$ 129	$ 248
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (788)	$ (758)	$ (698)
Cash (paid) received for income taxes, net	(4)	12	53
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 501	$ 400	$ 421
Inventory transfers to property, plant and equipment	87	275	88
Operating lease right-of-use assets	8	369	1,843
Allowance for equity funds used during construction	73	115	77
Issuance of common stock for reinvested dividends and/or equity awards	60	67	63

See Notes to Consolidated Financial Statements

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

	Dec. 31 2021	Dec. 31 2020
Assets		
Current assets		
Cash and cash equivalents	$ 166	$ 129
Accounts receivable, net	1,018	916
Accrued unbilled revenues	862	714
Inventories	631	535
Regulatory assets	1,106	640
Derivative instruments	123	49
Prepaid taxes	44	42
Prepayments and other	289	250
Total current assets	4,239	3,275
Property, plant and equipment, net	45,457	42,950
Other assets		
Nuclear decommissioning fund and other investments	3,628	3,096
Regulatory assets	2,738	2,737
Derivative instruments	67	30
Operating lease right-of-use assets	1,291	1,490
Other	431	379
Total other assets	8,155	7,732
Total assets	$ 57,851	$ 53,957
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 601	$ 421
Short-term debt	1,005	584
Accounts payable	1,409	1,237
Regulatory liabilities	271	311
Taxes accrued	569	578
Accrued interest	209	203
Dividends payable	249	231
Derivative instruments	69	53
Operating lease liabilities	205	214
Other	459	407
Total current liabilities	5,046	4,239
Deferred credits and other liabilities		
Deferred income taxes	4,894	4,746
Deferred investment tax credits	53	45
Regulatory liabilities	5,405	5,302
Asset retirement obligations	3,151	2,884
Derivative instruments	105	131
Customer advances	196	197
Pension and employee benefit obligations	306	666
Operating lease liabilities	1,146	1,344
Other	158	183
Total deferred credits and other liabilities	15,414	15,498
Commitments and contingencies		
Capitalization		
Long-term debt	21,779	19,645
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 544,025,269 and 537,438,394 shares outstanding at Dec. 31, 2021 and Dec. 31, 2020, respectively	1,360	1,344
Additional paid in capital	7,803	7,404
Retained earnings	6,572	5,968
Accumulated other comprehensive loss	(123)	(141)
Total common stockholders' equity	15,612	14,575
Total liabilities and equity	$ 57,851	$ 53,957

See Notes to Consolidated Financial Statements

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2018	514,036,787	$ 1,285	$ 6,168	$ 4,893	$ (124)	$ 12,222
Net income				1,372		1,372
Other comprehensive income					(17)	(17)
Dividends declared on common stock ($1.62 per share)				(846)		(846)
Issuances of common stock	10,507,943	26	468			494
Repurchases of common stock	(5,730)	—	—			—
Share-based compensation			20	(6)		14
Balance at Dec. 31, 2019	524,539,000	$ 1,311	$ 6,656	$ 5,413	$ (141)	$ 13,239
Net Income				1,473		1,473
Dividends declared on common stock ($1.72 per share)				(909)		(909)
Issuances of common stock	12,953,869	33	731			764
Repurchase of common stock	(54,475)	—	(4)			(4)
Share-based compensation			21	(7)		14
Adoption of ASC Topic 326				(2)		(2)
Balance at Dec. 31, 2020	537,438,394	$ 1,344	$ 7,404	$ 5,968	$ (141)	$ 14,575
Net income				1,597		1,597
Other comprehensive income					18	18
Dividends declared on common stock ($1.83 per share)				(989)		(989)
Issuances of common stock	6,586,875	16	387			403
Share-based compensation			12	(4)		8
Balance at Dec. 31, 2021	544,025,269	$ 1,360	$ 7,803	$ 6,572	$ (123)	$ 15,612

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

General — Xcel Energy Inc.’s utility subsidiaries are engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas.

Xcel Energy’s regulated operations include the activities of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in regulated operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipeline, storage and compression facilities.

Xcel Energy Inc.’s nonregulated subsidiaries include Eloigne, Capital Services, Venture Holdings and Nicollet Project Holdings. Eloigne invests in rental housing projects that qualify for low-income housing tax credits. Capital Services procures equipment for construction of renewable generation facilities at other subsidiaries. Venture Holdings invests in limited partnerships, including EIP funds with portfolios of investments in energy technology companies. Nicollet Project Holdings invests in nonregulated assets such as the MEC generating facility (through July 2020) and Minnesota community solar gardens. Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., Xcel Energy Transmission Holding Company, LLC, Nicollet Holdings Company, LLC, Xcel Energy Nuclear Services Holdings, LLC and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy’s consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. All intercompany transactions and balances are eliminated unless a different treatment is appropriate for rate regulated transactions. Xcel Energy uses the equity method of accounting for its investments in EIP funds and WYCO.

Xcel Energy has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy’s proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy’s proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income.

Xcel Energy’s consolidated financial statements are presented in accordance with GAAP. All of the utility subsidiaries’ underlying accounting records also conform to the FERC uniform system of accounts. Certain amounts in the consolidated financial statements or notes have been reclassified for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

Xcel Energy has evaluated events occurring after Dec. 31, 2021 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — Xcel Energy uses estimates based on the best information available in recording transactions and balances resulting from business operations.

Estimates are used for items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — Xcel Energy Inc.’s regulated utility subsidiaries account for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, the utility subsidiaries may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy’s results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities.

Xcel Energy uses rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries’ net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which would be refundable to utility customers over the remaining life of the related assets. Xcel Energy anticipates that a tax rate increase would result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Xcel Energy reports interest and penalties related to income taxes within other (expense) income or interest charges in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation in Regulated Operations — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Xcel Energy records depreciation expense using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs of Xcel Energy's utility subsidiaries are recovered in rates as authorized by the appropriate regulatory entities. The amount of removal costs is based on current factors used in existing depreciation rates. Accumulated removal costs are reflected in the consolidated balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.5% for 2021, 3.4% for 2020 and 3.3% for 2019.

See Note 3 for further information.

AROs — Xcel Energy accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 12 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility's expected service life, typically based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Notes 10 and 12 for further information.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 11 for further information.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 12 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. Xcel Energy recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

Xcel Energy does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. Xcel Energy presents its revenues net of any excise or sales taxes or fees. The utility subsidiaries recognize physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO are recorded on a net basis in cost of sales.

See Note 6 for further information.

Cash and Cash Equivalents — Xcel Energy considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

As of Dec. 31, 2021 and 2020, the allowance for bad debts was $106 million and $79 million, respectively.

Inventory — Inventory is recorded at average cost and consisted of the following:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Inventories		
Materials and supplies	$ 289	$ 275
Fuel	182	176
Natural gas	160	84
Total inventories	$ 631	$ 535

Equity Method Investments — The equity method of accounting is used for investments in WYCO and EIP funds, which results in Xcel Energy's recognition of its share of these investees' GAAP pretax earnings, based on Xcel Energy's proportional ownership interest. For investments in EIP funds, this includes Xcel Energy's share of fund expenses and realized gains and losses, as well as unrealized gains and losses resulting from valuations of the funds' investments in emerging energy technology companies.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements.

Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues and interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

See Note 10 for further information.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the consolidated statements of income.

Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 10 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling/sales true up and CIP/DSM programs) qualify as alternative revenue programs. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate or from other instances where the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs — Costs incurred for DSM and CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emission allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling costs. This method amortizes costs over the period between refueling outages consistent with rate recovery.

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. In certain jurisdictions, Xcel Energy reduces recoverable fuel and purchased power costs for the cost of RECs received. An inventory accounting model is used to account for RECs recognized on the consolidated balance sheets, however these assets are classified as regulatory assets if amounts are recoverable in future rates.

Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Cost of RECs that are utilized to support commodity trading activities are recorded in a similar manner as the associated commodities and are shown on a net basis in electric operating revenues in the consolidated statements of income.

2. Accounting Pronouncements

Recently Adopted

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

Xcel Energy implemented the guidance using a modified-retrospective approach, recognizing a cumulative effect charge of $2 million (after tax) to retained earnings on Jan. 1, 2020. Other than first-time recognition of an allowance for bad debts on accrued unbilled revenues, the Jan. 1, 2020, adoption of ASC Topic 326 did not have a significant impact on Xcel Energy's consolidated financial statements.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Property, plant and equipment, net		
Electric plant	$ 48,680	$ 47,104
Natural gas plant	7,758	7,135
Common and other property	2,602	2,503
Plant to be retired [a]	1,200	677
CWIP	1,969	1,877
Total property, plant and equipment	62,209	59,296
Less accumulated depreciation	(17,060)	(16,657)
Nuclear fuel	3,081	2,970
Less accumulated amortization	(2,773)	(2,659)
Property, plant and equipment, net	$ 45,457	$ 42,950

(a) Includes regulator-approved retirements of Comanche Units 1 and 2 and jointly owned Craig Unit 1 for PSCo, and Sherco Units 1, 2 and 3 and A.S. King for NSP-Minnesota. Also includes SPS' expected retirement of Tolk and conversion of Harrington to natural gas, and PSCo's planned retirement of jointly owned Craig Unit 2.

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2021:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
NSP-Minnesota			
Electric generation:			
Sherco Unit 3	$ 620	$ 451	59 %
Sherco common facilities	178	108	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	3	50
Huntley Wilmarth	48	1	50
CapX2020	952	127	51
Total NSP-Minnesota [a]	$ 1,814	$ 694	

(a) Projects additionally include $7 million in CWIP.

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
NSP-Wisconsin			
Electric transmission:			
La Crosse, WI to Madison, WI	$ 177	$ 15	37 %
CapX2020	169	28	80
Total NSP-Wisconsin [a]	$ 346	$ 43	

(a) Projects additionally include $2 million in CWIP.

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
PSCo			
Electric generation:			
Hayden Unit 1	$ 156	$ 99	76 %
Hayden Unit 2	151	78	37
Hayden common facilities	42	27	53
Craig Units 1 and 2	81	48	10
Craig common facilities	39	25	7
Comanche Unit 3	917	154	67
Comanche common facilities	28	2	82
Electric transmission:			
Transmission and other facilities	182	63	Various
Gas transmission:			
Rifle, CO to Avon, CO	22	8	60
Gas transmission compressor	8	2	50
Total PSCo [(a)]	$ 1,626	$ 506	

(a) Projects additionally include $4 million in CWIP.

Each company's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2021		Dec. 31, 2020	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	11	Various	$ 77	$ 944	$ 82	$ 1,268
Deferred natural gas, electric, steam energy/fuel costs		One to five years	504	543	14	18
Recoverable deferred taxes on AFUDC		Plant lives	—	289	—	283
Excess deferred taxes — TCJA	7	Various	14	219	16	229
Depreciation differences		One to 10 years	16	173	16	154
Environmental remediation costs	1, 12	Various	14	92	16	113
Texas revenue surcharges		One to two years	20	64	54	17
Sales true-up and revenue decoupling		One to two years	33	56	101	28
Benson biomass PPA termination and asset purchase		Eight years	10	55	10	65
Renewable resources and environmental initiatives		One to two years	170	48	129	12
PI extended power uprate		13 years	4	46	3	49
Purchased power contract costs		Term of related contract	9	45	7	54
Conservation programs [(a)]	1	One to two years	21	35	26	36
Losses on reacquired debt		Term of related debt	3	35	4	38
Contract valuation adjustments [(b)]	1, 10	Term of related contract	22	34	23	48
State commission adjustments		Plant lives	1	32	1	32
Laurentian biomass PPA termination		Two years	18	18	18	36
Nuclear refueling outage costs	1	One to two years	37	16	28	10
Property tax		Various	16	16	16	21
Gas pipeline inspection and remediation costs		One to two years	33	12	26	9
Net AROs [(c)]	1, 12	Various	—	(112)	—	139
Other		Various	84	78	50	78
Total regulatory assets			$ 1,106	$ 2,738	$ 640	$ 2,737

(a) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.
(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.
(c) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2021		Dec. 31, 2020	
Regulatory Liabilities			**Current**	**Noncurrent**	**Current**	**Noncurrent**
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 26	$ 3,230	$ 20	$ 3,368
Plant removal costs	1, 12	Various	—	1,655	—	1,520
Effects of regulation on employee benefit costs [(b)]		Various	—	235	—	221
Renewable resources and environmental initiatives		Various	1	101	5	59
ITC deferrals	1	Various	—	53	—	51
Revenue decoupling		One to two years	9	41	10	41
Contract valuation adjustments [(c)]	1, 10	One to three years	56	1	19	—
Deferred natural gas, electric, steam energy/fuel costs		Less than one year	50	—	84	—
Conservation programs [(d)]	1	Less than one year	42	—	49	—
DOE settlement		Less than one year	14	14	23	—
Other		Various	73	75	101	42
Total regulatory liabilities [(e)]			$ 271	$ 5,405	$ 311	$ 5,302

(a) Includes the revaluation of recoverable/regulated plant accumulated deferred income taxes and revaluation impact of non-plant accumulated deferred income taxes due to the TCJA.
(b) Includes regulatory amortization and certain 2018 TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset.
(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.
(d) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.
(e) Revenue subject to refund of $17 million for both 2021 and 2020 is included in other current liabilities.

At Dec. 31, 2021 and 2020, Xcel Energy’s regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, regulatory assets included $1,718 million and $812 million at Dec. 31, 2021 and 2020, respectively, of past expenditures not earning a return. Amounts are related to funded pension obligations, sales true-up and revenue decoupling, purchased natural gas and electric energy costs (including those related to Winter Storm Uri), various renewable resources and certain environmental initiatives.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Short-Term Debt — Xcel Energy meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities and term loan agreements.

Commercial paper and term loan borrowings outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2021	Year Ended Dec. 31		
		2021	2020	2019
Borrowing limit	$ 3,100	$ 3,100	$ 3,100	$ 3,600
Amount outstanding at period end	1,005	1,005	584	595
Average amount outstanding	1,200	1,399	1,126	1,115
Maximum amount outstanding	1,774	2,054	2,080	1,780
Weighted average interest rate, computed on a daily basis	0.54 %	0.57 %	1.45 %	2.72 %
Weighted average interest rate at period end	0.31	0.31	0.23	2.34

Term Loan Agreements — In the fourth quarter of 2021, Xcel Energy repaid its $1.2 billion 364-Day Term Loan Agreement.

Bilateral Credit Agreement — In April 2021, NSP-Minnesota's uncommitted bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of Dec. 31, 2021, NSP-Minnesota had $45 million outstanding letters of credit under the $75 million the Bilateral Credit Agreement.

Letters of Credit — Xcel Energy uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2021 and 2020, there were $19 million and $20 million of letters of credit outstanding under the credit facilities, respectively. Amounts approximate their fair value.

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

Terms of Credit Agreements — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements is $3.1 billion, with a swingline subfacility for Xcel Energy up to $75 million. The amended credit agreements mature in June 2024.

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio [(a)]		Amount Facility May Be Increased (millions of dollars)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
	2021	2020		
Xcel Energy Inc. [(c)]	60 %	59 %	$ 250	2
NSP-Wisconsin	49	46	N/A	1
NSP-Minnesota	47	47	100	2
SPS	47	48	50	2
PSCo	44	44	100	2

(a) Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.
(b) All extension requests are subject to majority bank group approval.
(c) The Xcel Energy Inc. credit facility has a cross-default provision that Xcel Energy Inc. would be in default on its borrowings under the facility if it or any of its subsidiaries (except NSP-Wisconsin as long as its total assets do not comprise more than 15% of Xcel Energy's consolidated total assets) default on indebtedness in an aggregate principal amount exceeding $75 million.

If Xcel Energy Inc. or its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2021, Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants.

Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available as of Dec. 31, 2021:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available
Xcel Energy Inc.	$ 1,250	$ 638	$ 612
PSCo	700	155	545
NSP-Minnesota	500	9	491
SPS	500	139	361
NSP-Wisconsin	150	83	67
Total	$ 3,100	$ 1,024	$ 2,076

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

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its utility subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2021 and 2020.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are subject to the liens of their first mortgage indentures. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long-term debt obligations for Xcel Energy Inc. and its utility subsidiaries as of Dec. 31 (in millions of dollars):

Xcel Energy Inc.

Financing Instrument	Interest Rate	Maturity Date	2021	2020
Unsecured senior notes	2.40 %	March 15, 2021	$ —	$ 400
Unsecured senior notes [(b)]	0.50	Oct. 15, 2023	500	500
Unsecured senior notes	3.30	June 1, 2025	250	250
Unsecured senior notes	3.30	June 1, 2025	350	350
Unsecured senior notes	3.35	Dec. 1, 2026	500	500
Unsecured senior notes [(a)]	1.75	March 15,2027	500	—
Unsecured senior notes	4.00	June 15, 2028	130	130
Unsecured senior notes	4.00	June 15, 2028	500	500
Unsecured senior notes	2.60	Dec. 1, 2029	500	500
Unsecured senior notes [(b)]	3.40	June 1, 2030	600	600
Unsecured senior notes [(a)]	2.35	Nov. 15, 2031	300	—
Unsecured senior notes	6.50	July 1, 2036	300	300
Unsecured senior notes	4.80	Sep. 15, 2041	250	250
Unsecured senior notes	3.50	Dec. 1, 2049	500	500
Unamortized discount			(8)	(7)
Unamortized debt issuance cost			(33)	(32)
Current maturities			—	(400)
Total long-term debt			$ 5,139	$ 4,341

(a) 2021 financing.
(b) 2020 financing.

NSP-Minnesota

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	2.15 %	Aug. 15, 2022	$ 300	$ 300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.125	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds [(a)]	2.25	April 1, 2031	425	—
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.125	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sep. 15, 2047	600	600
First mortgage bonds	2.90	March 1, 2050	600	600
First mortgage bonds [(b)]	2.60	June 1, 2051	700	700
First mortgage bonds [(a)]	3.20	April 1,2052	425	—
Other long-term debt			3	—
Unamortized discount			(44)	(42)
Unamortized debt issuance cost			(62)	(54)
Current maturities			(300)	—
Total long-term debt			$ 6,447	$ 5,904

(a) 2021 financing.
(b) 2020 financing.

NSP-Wisconsin

Financing Instrument	Interest Rate	Maturity Date	2021	2020
City of La Crosse resource recovery bond	6.00 %	Nov. 1, 2021	$ —	$ 19
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	6.375	Sept. 1, 2038	200	200
First mortgage bonds	3.70	Oct. 1, 2042	100	100
First mortgage bonds	3.75	Dec. 1, 2047	100	100
First mortgage bonds	4.20	Sept. 1, 2048	200	200
First mortgage bonds [(b)]	3.05	May 1, 2051	100	100
First mortgage bonds [(a)]	2.82	May 1, 2051	100	—
Other long-term debt			1	—
Unamortized discount			(4)	(4)
Unamortized debt issuance cost			(10)	(9)
Current maturities			—	(19)
Total long-term debt			$ 987	$ 887

(a) 2021 financing.
(b) 2020 financing.

PSCo

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	2.25 %	Sept. 15, 2022	$ 300	$ 300
First mortgage bonds	2.50	March 15, 2023	250	250
First mortgage bonds	2.90	May 15, 2025	250	250
First mortgage bonds	3.70	June 15, 2028	350	350
First mortgage bonds (b)	1.90	Jan. 15, 2031	375	375
First mortgage bonds (a)	1.875	June 15, 2031	750	—
First mortgage bonds	6.25	Sept. 1, 2037	350	350
First mortgage bonds	6.50	Aug. 1, 2038	300	300
First mortgage bonds	4.75	Aug. 15, 2041	250	250
First mortgage bonds	3.60	Sept. 15, 2042	500	500
First mortgage bonds	3.95	March 15, 2043	250	250
First mortgage bonds	4.30	March 15, 2044	300	300
First mortgage bonds	3.55	June 15, 2046	250	250
First mortgage bonds	3.80	June 15, 2047	400	400
First mortgage bonds	4.10	June 15, 2048	350	350
First mortgage bonds	4.05	Sept. 15, 2049	400	400
First mortgage bonds	3.20	March 1, 2050	550	550
First mortgage bonds (b)	2.70	Jan. 15, 2051	375	375
Unamortized discount			(33)	(30)
Unamortized debt issuance cost			(50)	(46)
Current maturities			(300)	—
Total long-term debt			$ 6,167	$ 5,724

(a) 2021 financing.
(b) 2020 financing.

SPS

Financing Instrument	Interest Rate	Maturity Date	2021	2020
First mortgage bonds	3.30 %	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds	4.40	Nov. 15, 2048	300	300
First mortgage bonds	3.75	June 15, 2049	300	300
First mortgage bonds (b)	3.15	May 1, 2050	350	350
First mortgage bonds (a)	3.15	May 1, 2050	250	—
Unamortized discount			(9)	(10)
Unamortized debt issuance cost			(28)	(26)
Total long-term debt			$ 3,013	$ 2,764

(a) 2020 financing re-opened in 2021.
(b) 2020 financing.

Other Subsidiaries

Financing Instrument	Interest Rate	Maturity Date	2021	2020
Various Eloigne affordable housing project notes	0.00% - 6.50%	2022 — 2055	$ 27	$ 27
Current maturities			(1)	(2)

Maturities of long-term debt:

(Millions of Dollars)	
2022	$ 601
2023	1,150
2024	552
2025	1,102
2026	501

Deferred Financing Costs — Deferred financing costs of approximately $184 million and $167 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2021 and 2020, respectively.

ATM Equity Offering — In November 2021, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $800 million of its common stock through an ATM program. As of Dec. 31, 2021, Xcel Energy Inc. had issued 5.33 million shares of common stock with net proceeds of $347 million through the ATM program.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2021 and 2020
Xcel Energy Inc.	7,000,000	$ 100	—
PSCo	10,000,000	0.01	—
SPS	10,000,000	1.00	—

Xcel Energy Inc. had the following common stock authorized/outstanding:

Common Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) as of Dec. 31, 2021	Common Stock Outstanding (Shares) as of Dec. 31, 2020
1,000,000,000	$ 2.50	544,025,269	537,438,394

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its utility subsidiaries to pay dividends. Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. Certain covenants also require Xcel Energy Inc. to be current on interest payments prior to dividend disbursements.

State regulatory commissions impose dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS, which are more restrictive than those imposed by the FERC. Requirements and actuals as of Dec. 31, 2021:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2021
NSP-Minnesota	47.2 %	57.6 %	52.9 %
NSP-Wisconsin	52.5	N/A	52.8
SPS (a)	45.0	55.0	54.5

(a) Excludes short-term debt.

Current maturities	(1)	(2)
Total long-term debt	$ 26	$ 25

(Amounts in Millions)	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1,558	$ 14,321	$ 15,332
NSP-Wisconsin (a)	11	2,091	N/A
SPS (b)	513	6,615	N/A

(a) Cannot pay annual dividends in excess of forecasted levels if its average equity-to-total capitalization ratio falls below the commission authorized level.
(b) May not pay a dividend that would cause a loss of its investment grade bond rating.

Issuance of securities by Xcel Energy Inc. is not generally subject to regulatory approval. However, utility financings and intra-system financings are subject to the jurisdiction of state regulatory commissions and/or the FERC. Xcel Energy may seek additional authorization as necessary.

Amounts authorized to issue as of Dec. 31, 2021:

(Millions of Dollars)	Long-Term Debt	Short-Term Debt
NSP-Minnesota	52.8% of total capitalization (a)	$ 2,300 (a)
NSP-Wisconsin	$ 150	150
SPS	—	600
PSCo	700 (b)	800

(a) NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization remains within the required range, and to issue short-term debt provided it does not exceed 15% of total capitalization.
(b) PSCo filed for additional long-term debt authorization in December 2021.

6. Revenues

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

	Year Ended Dec. 31, 2021			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,194	$ 1,222	$ 45	$ 4,461
C&I	5,050	640	30	5,720
Other	127	—	7	134
Total retail	8,371	1,862	82	10,315
Wholesale	1,540	—	—	1,540
Transmission	604	—	—	604
Other	61	148	—	209
Total revenue from contracts with customers	10,576	2,010	82	12,668
Alternative revenue and other	629	122	12	763
Total revenues	$ 11,205	$ 2,132	$ 94	$ 13,431

	Year Ended Dec. 31, 2020			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,066	$ 975	$ 42	$ 4,083
C&I	4,596	462	27	5,085
Other	125	—	6	131
Total retail	7,787	1,437	75	9,299
Wholesale	759	—	—	759
Transmission	579	—	—	579
Other	73	137	—	210
Total revenue from contracts with customers	9,198	1,574	75	10,847
Alternative revenue and other	604	62	13	679
Total revenues	$ 9,802	$ 1,636	$ 88	$ 11,526

	Year Ended Dec. 31, 2019			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,877	$ 1,127	$ 41	$ 4,045
C&I	4,844	567	29	5,440
Other	130	—	4	134
Total retail	7,851	1,694	74	9,619
Wholesale	737	—	—	737
Transmission	507	—	—	507
Other	49	120	—	169
Total revenue from contracts with customers	9,144	1,814	74	11,032
Alternative revenue and other	431	54	12	497
Total revenues	$ 9,575	$ 1,868	$ 86	$ 11,529

7. Income Taxes

Federal Loss Carryback Claims - In 2020, Xcel Energy identified certain expense related to tax years 2009 - 2011 that qualify for an extended carryback claim. As a result, a tax benefit of approximately $13 million was recognized in 2020.

Federal Audit — Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2014 - 2016	December 2022
2018	September 2022

Additionally, the statute of limitations related to the federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to the additional federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions and various other state income-based tax returns.

As of Dec. 31, 2021, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Year
Colorado	2014
Minnesota	2014
Texas	2016
Wisconsin	2016

- In April 2021, Texas began an audit of tax years 2016-2019. As of Dec. 31, 2021, no material adjustments have been proposed.
- In March 2021, Wisconsin began an audit of tax years 2016 - 2019. As of Dec. 31, 2021, no material adjustments have been proposed.
- In July 2020, Minnesota began an audit of tax years 2015 - 2018. As of Dec. 31, 2021, no material adjustments have been proposed.
- No other state income tax audits in progress for its major operating jurisdictions as of Dec. 31, 2021.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits - permanent vs. temporary:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	$ 47	$ 41
Unrecognized tax benefit — Temporary tax positions	11	11
Total unrecognized tax benefit	$ 58	$ 52

Changes in unrecognized tax benefits:

(Millions of Dollars)	2021	2020	2019
Balance at Jan. 1	$ 52	$ 44	$ 37
Additions based on tax positions related to the current year	5	9	10
Reductions based on tax positions related to the current year	—	(2)	(4)
Additions for tax positions of prior years	2	35	1
Reductions for tax positions of prior years	(1)	(34)	—
Balance at Dec. 31	$ 58	$ 52	$ 44

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	$ (36)	$ (31)

As the IRS progresses its review of the tax loss carryback claims and as state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $28 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2021	2020	2019
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (3)	$ —	$ —
Interest expense related to unrecognized tax benefits	—	(3)	—
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (3)	$ (3)	$ —

No penalties were accrued related to unrecognized tax benefits as of Dec. 31, 2021, 2020 or 2019.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31:

(Millions of Dollars)	2021	2020
Federal NOL carryforward	$ 765	$ —
Federal tax credit carryforwards	1,172	791
State NOL carryforwards	1,648	839
Valuation allowances for state NOL carryforwards	(3)	(4)
State tax credit carryforwards, net of federal detriment [(a)]	89	89
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(64)	(64)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2021 and 2020.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $17 million as of Dec. 31, 2021 and 2020.

Federal carryforward periods expire between 2031 and 2041 and state carryforward periods expire starting 2022.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2021	2020	2019
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	5.0	4.9	4.9
(Decreases) increases in tax from:			
Wind PTCs	(23.4)	(15.7)	(9.4)
Plant regulatory differences [(a)]	(6.2)	(7.6)	(5.8)
Other tax credits, net NOL & tax credit allowances	(1.1)	(1.2)	(1.7)
NOL Carryback	—	(0.9)	—
Change in unrecognized tax benefits	0.4	0.5	0.5
Other, net	(0.3)	(1.4)	(1.0)
Effective income tax rate	(4.6)%	(0.4)%	8.5 %

(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 and additional prepaid pension asset amortization.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2021	2020	2019
Current federal tax expense (benefit)	$ 15	$ (13)	$ (16)
Current state tax (benefit) expense	(2)	2	4
Current change in unrecognized tax expense	1	18	2
Deferred federal tax (benefit) expense	(183)	(89)	55
Deferred state tax expense	99	91	83
Deferred change in unrecognized tax expense (benefit)	5	(10)	5
Deferred ITCs	(5)	(5)	(5)
Total income tax (benefit) expense	$ (70)	$ (6)	$ 128

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2021	2020	2019
Deferred tax expense excluding items below	$ 148	$ 237	$ 344
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(221)	(247)	(206)
Tax (benefit) expense allocated to other comprehensive income, adoption of ASC Topic 326, and other	(6)	2	5
Deferred tax (benefit) expense	$ (79)	$ (8)	$ 143

Components of net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2021	2020 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 6,231	$ 5,810
Operating lease assets	351	400
Regulatory assets	598	603
Deferred fuel costs	262	(6)
Pension expense	175	176
Other	93	74
Total deferred tax liabilities	$ 7,710	$ 7,057
Deferred tax assets:		
Regulatory liabilities	$ 780	$ 806
Operating lease liabilities	351	400
Tax credit carryforward	1,261	880
NOL carryforward	247	37
NOL and tax credit valuation allowances	(64)	(64)
Other employee benefits	119	141
Deferred ITCs	15	13
Other	107	98
Total deferred tax assets	$ 2,816	$ 2,311
Net deferred tax liability	$ 4,894	$ 4,746

(a) Prior periods have been reclassified to conform to current year presentation.

8. Share-Based Compensation

Incentive Plan Including Share-Based Compensation — Xcel Energy has an incentive plan which includes share-based payment elements, the Amended and Restated 2015 Omnibus Incentive Plan with 7.0 million equity shares authorized.

Restricted Stock — The Amended and Restated 2015 Omnibus Incentive Plan allows certain employees to elect to receive shares of common or restricted stock. Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Restricted stock has a fair value equal to the market trading price of Xcel Energy stock at the grant date.

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2021	2020	2019
Granted shares	2	1	13
Grant date fair value	$ 61.54	$ 70.26	$ 53.46

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2021	15	$ 56.68
Granted	2	61.54
Forfeited	—	70.26
Vested	(9)	49.71
Dividend equivalents	—	66.73
Nonvested restricted stock at Dec. 31, 2021	8	67.26

Other Equity Awards — Xcel Energy‘s Board of Directors has granted equity awards under the Amended and Restated 2015 Omnibus Incentive Plan, which includes various vesting conditions and performance goals. At the end of the restricted period, such grants will be awarded if vesting conditions and/or performance goals are met.

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. A total of 0.2 million, 0.2 million, and 0.3 million time-based equity shares subject only to service conditions were granted annually in 2021, 2020 and 2019, respectively.

The performance conditions for a portion of the awards granted from 2019 to 2021 are based on relative TSR and environmental goals. Equity awards with performance conditions will be settled or forfeited after three years, with payouts ranging from zero to 200% depending on achievement.

Equity award units granted to employees (excluding restricted stock):

(Units in Thousands)	2021	2020	2019
Granted units	421	411	483
Weighted average grant date fair value	$ 66.03	$ 62.92	$ 49.67

Equity awards vested:

(Units in Thousands, Fair Value in Millions)	2021	2020	2019
Vested Units	392	442	464
Total Fair Value	$ 27	$ 29	$ 29

Changes in the nonvested portion of equity award units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2021	780	$ 55.68
Granted	421	66.03
Forfeited	(146)	61.76
Vested	(392)	48.91
Dividend equivalents	32	58.00
Nonvested Units at Dec. 31, 2021	695	64.59

Stock Equivalent Units — Non-employee members of Xcel Energy's Board of Directors may elect to receive their annual equity grant as stock equivalent units in lieu of common stock. Each unit's value is equal to one share of common stock. The annual equity grant is vested as of the date of each member's election to the Board of Directors; there is no further service or other condition. Directors may also elect to receive their cash fees as stock equivalent units in lieu of cash. Stock equivalent units are payable as a distribution of common stock upon a director's termination of service.

Stock equivalent units granted:

(Units in Thousands)	2021	2020	2019
Granted units	31	33	29
Weighted average grant date fair value	$ 68.15	$ 61.61	$ 58.44

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2021	630	$ 36.28
Granted	31	68.15
Units distributed	(73)	31.47
Dividend equivalents	16	66.98
Stock equivalent units at Dec. 31, 2021	604	39.27

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Amended and Restated 2015 Omnibus Incentive Plan. This plan allows Xcel Energy to attach various performance goals to the awards granted. The liability awards have been historically dependent on relative TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to a peer group of other utility companies. Potential payouts of the awards range from zero to 200%.

TSR liability awards granted:

(In Thousands)	2021	2020	2019
Awards granted	221	212	225

TSR liability awards settled:

(Units In Thousands, Settlement Amount in Millions)	2021	2020	2019
Awards settled	446	476	466
Settlement amount (cash, common stock and deferred amounts)	$ 27	$ 33	$ 25

TSR liability awards of $22 million were settled in cash in 2021.

Share-Based Compensation Expense — Other than for restricted stock, vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target. Additionally, approximately 0.2 million, 0.2 million, and 0.3 million of equity award units were granted in 2021, 2020, and 2019, respectively, with vesting subject only to service conditions of three years.

Generally, these instruments are considered to be equity awards as the award settlement determination (shares or cash) is made by Xcel Energy, not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement.

Grant date fair value of equity awards is expensed over the service period. TSR liability awards have been historically settled partially in cash, and do not qualify as equity awards, but rather are accounted for as liabilities. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the shares on the date the award is settled.

Compensation costs related to share-based awards:

(Millions of Dollars)	2021	2020	2019
Compensation cost for share-based awards [(a)]	$ 31	$ 73	$ 58
Tax benefit recognized in income	8	19	15

(a) Compensation costs for share-based payments are included in O&M expense.

There was approximately $28 million in 2021 and $51 million in 2020 of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the unrecognized amount over a weighted average period of 1.6 years.

9. Earnings Per Share

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

Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. has common stock equivalents related to forward equity agreements and certain equity awards in share-based compensation arrangements. Common stock equivalents include commitments to issue common stock related to time-based equity compensation awards.

Stock equivalent units granted to Xcel Energy's Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these. Restricted stock issued to employees under the Executive Annual Incentive Award Plan is included in common shares outstanding when granted.

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

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

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

(Shares in Millions)	2021	2020	2019
Basic	539	527	519
Diluted [(a)]	540	528	520

(a) Diluted common shares outstanding included common stock equivalents of 0.3 million, 1.1 million and 1.3 million shares for 2021, 2020 and 2019, respectively.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled fund investments may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third-party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the consolidated financial statements.

Non-Derivative Fair Value Measurements

Nuclear Decommissioning Fund

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

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

Unrealized gains for the nuclear decommissioning fund were $1.3 billion and $981 million as of Dec. 31, 2021 and 2020, respectively, and unrealized losses were $7 million and $5 million as of Dec. 31, 2021 and 2020, respectively.

Non-derivative instruments with recurring fair value measurements:

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

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

(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
	Dec. 31, 2020					
		Fair Value				
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 40	$ 40	$ —	$ —	$ —	$ 40
Commingled funds	787	—	—	—	1,041	1,041
Debt securities	528	—	572	13	—	585
Equity securities	446	1,109	2	—	—	1,111
Total	$ 1,801	$ 1,149	$ 574	$ 13	$ 1,041	$ 2,777

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $165 million of equity investments in unconsolidated subsidiaries and $154 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2021 and 2020, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2021:

(Millions of Dollars)	Due in 1 year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 years	Total
	Final Contractual Maturity				
Debt securities	$ 4	$ 149	$ 208	$ 314	$ 675

Rabbi Trusts

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

Cost and fair value of assets held in rabbi trusts:

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

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

(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
	Dec. 31, 2020				
		Fair Value			
Rabbi Trusts [(a)]					
Cash equivalents	$ 32	$ 32	$ —	$ —	$ 32
Mutual funds	60	70	—	—	70
Total	$ 92	$ 102	$ —	$ —	$ 102

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

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes, with changes in fair value prior to settlement recorded as other comprehensive income.

As of Dec. 31, 2021, accumulated other comprehensive loss related to settled interest rate derivatives included $5 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2021, Xcel Energy had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but may not be designated as qualifying hedging transactions. The classification of unrealized losses or gains on these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms.

As of Dec. 31, 2021, Xcel Energy had no commodity contracts designated as cash flow hedges.

Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [(a)(b)]	Dec. 31, 2021	Dec. 31, 2020
MWh of electricity	80	87
MMBtu of natural gas	156	175

(a) Not reflective of net positions in the underlying commodities.
(b) Notional amounts for options included on a gross basis but weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the consolidated balance sheets.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2021, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $83 million or 38% of this credit exposure, had investment grade credit ratings from S&P, Moody's Investor Services or Fitch Ratings. Three of the 10 most significant counterparties, comprising $44 million or 20% of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $38 million or 18% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income:

(Millions of Dollars)	2021	2020	2019
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (85)	$ (80)	$ (60)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	4	(10)	(23)
After-tax net realized losses on derivative transactions reclassified into earnings	6	5	3
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (75)	$ (85)	$ (80)

Impact of derivative activity:

	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2021		
Derivatives designated as cash flow hedges		
Interest rate	$ 5	$ —
Total	$ 5	$ —
Other derivative instruments		
Electric commodity	$ —	$ 32
Natural gas commodity	—	(4)
Total	$ —	$ 28
Year Ended Dec. 31, 2020		
Interest rate	$ (13)	$ —
Total	$ (13)	$ —
Other derivative instruments		
Electric commodity	$ —	$ (5)
Natural gas commodity	—	(13)
Total	$ —	$ (18)
Year Ended Dec. 31, 2019		
Interest rate	$ (30)	$ —
Total	$ (30)	$ —
Other derivative instruments		
Electric commodity	$ —	$ 8
Natural gas commodity	—	(9)
Total	$ —	$ (1)

	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Year Ended Dec. 31, 2021			
Derivatives designated as cash flow hedges			
Interest rate	$ 8 [(a)]	$ —	$ —
Total	$ 8	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 63 [(b)]
Electric commodity	—	(23) [(c)]	—
Natural gas commodity	—	5 [(d)]	(22) [(d)]
Total	$ —	$ (18)	$ 41
Year Ended Dec. 31, 2020			
Derivatives designated as cash flow hedges			
Interest rate	$ 7 [(a)]	$ —	$ —
Total	$ 7	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (1) [(b)]
Electric commodity	—	(3) [(c)]	—
Natural gas commodity	—	10 [(d)]	(13) [(d)]
Total	$ —	$ 7	$ (14)
Year Ended Dec. 31, 2019			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 [(a)]	$ —	$ —
Total	$ 4	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 2 [(b)]
Electric commodity	—	(5) [(c)]	—
Natural gas commodity	—	2 [(d)]	(7) [(d)]
Total	$ —	$ (3)	$ (5)

(a) Recorded to interest charges.
(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.
(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate.
(d) Settlement losses related to natural gas operations are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2021, 2020 and 2019.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase and normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. As of Dec. 31, 2021 and 2020, there were $3 million and $4 million of derivative instruments in a liability position with such underlying contract provisions, respectively. Certain contracts also contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under the other financing arrangements related to payment terms or other covenants.

As of Dec. 31, 2021 and 2020, there were approximately $64 million and $60 million of derivative instruments in a liability position with such underlying contract provisions, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. Provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2021 and 2020.

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

	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 22	$ 137	$ 21	$ 180	$ (134)	$ 46	$ 2	$ 67	$ 1	$ 70	$ (52)	$ 18
Electric commodity	—	—	57	57	(1)	56	—	—	20	20	(1)	19
Natural gas commodity	—	18	—	18	—	18	—	9	—	9	—	9
Total current derivative assets	$ 22	$ 155	$ 78	$ 255	$ (135)	120	$ 2	$ 76	$ 21	$ 99	$ (53)	46
PPAs (b)						3						3
Current derivative instruments						$ 123						$ 49
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 16	$ 63	$ 89	$ 168	$ (107)	$ 61	$ 8	$ 66	$ 8	$ 82	$ (62)	$ 20
Total noncurrent derivative assets	$ 16	$ 63	$ 89	$ 168	$ (107)	61	$ 8	$ 66	$ 8	$ 82	$ (62)	20
PPAs (b)						6						10
Noncurrent derivative instruments						$ 67						$ 30

	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 19	$ 148	$ 20	$ 187	$ (143)	$ 44	$ 4	$ 64	$ 17	$ 85	$ (58)	$ 27
Electric commodity	—	—	1	1	(1)	—	—	—	1	1	(1)	—
Natural gas commodity	—	8	—	8	—	8	—	9	—	9	—	9
Total current derivative liabilities	$ 19	$ 156	$ 21	$ 196	$ (144)	52	$ 4	$ 73	$ 18	$ 95	$ (59)	36
PPAs (b)						17						17
Current derivative instruments						$ 69						$ 53
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 18	$ 48	$ 127	$ 193	$ (128)	$ 65	$ 3	$ 58	$ 60	$ 121	$ (47)	$ 74
Total noncurrent derivative liabilities	$ 18	$ 48	$ 127	$ 193	$ (128)	65	$ 3	$ 58	$ 60	$ 121	$ (47)	74
PPAs (b)						40						57
Noncurrent derivative instruments						$ 105						$ 131

(a) Xcel Energy nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement and all derivative instruments and related collateral amounts were subject to master netting agreements as of Dec. 31, 2021 and 2020. At Dec. 31, 2021, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2020, derivative assets and liabilities include $15 million of obligations to return cash collateral. At Dec. 31, 2021 and 2020, derivative assets and liabilities include rights to reclaim cash collateral of $30 million and $6 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, contracts are no longer adjusted to fair value and the previous carrying value of these contracts is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

	Year Ended Dec. 31		
(Millions of Dollars)	2021	2020	2019
Balance at Jan. 1	$ (49)	$ 4	$ 29
Purchases	65	51	44
Settlements	(158)	(73)	(64)
Net transactions recorded during the period:			
Gains (losses) recognized in earnings [(a)]	49	(39)	(8)
Net gains recognized as regulatory assets and liabilities	112	8	3
Balance at Dec. 31	$ 19	$ (49)	$ 4

(a) Level 3 losses recognized in earnings are subject to offsetting gains of derivative instruments categorized as levels 1 and 2 in the income statement.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for Dec. 31, 2021, 2020 and 2019.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2021		2020	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 22,380	$ 25,232	$ 20,066	$ 24,412

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2021 and 2020, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

11. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits. The average annual interest crediting rates for these plans was 2.03, 1.89 and 2.82% in 2021, 2020, and 2019, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants.

The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows.

Obligations of the SERP and nonqualified plan as of Dec. 31, 2021 and 2020 were $43 million and $43 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2021 and $6 million in 2020.

Xcel Energy's investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as long-term projected return levels.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2021 were above the assumed level of 6.49%.
- Investment returns in 2020 were above the assumed level of 6.87%.
- Investment returns in 2019 were above the assumed level of 6.87%.
- In 2022, expected investment-return assumption is 6.49%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations consider many factors and generally result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

	Dec. 31, 2021 [(a)]					Dec. 31, 2020 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 133	$ —	$ —	$ —	$ 133	$ 209	$ —	$ —	$ —	$ 209
Commingled funds	1,324	—	—	1,143	2,467	1,462	—	—	1,115	2,577
Debt securities	—	959	5	—	964	—	714	4	—	718
Equity securities	67	—	—	—	67	77	—	—	—	77
Other	—	7	—	32	39	13	5	—	—	18
Total	$ 1,524	$ 966	$ 5	$ 1,175	$ 3,670	$ 1,761	$ 719	$ 4	$ 1,115	$ 3,599

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

For each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2021 [(a)]					Dec. 31, 2020 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 28	$ —	$ —	$ —	$ 28	$ 27	$ —	$ —	$ —	$ 27
Insurance contracts	—	52	—	—	52	—	50	—	—	50
Commingled funds	64	—	—	77	141	72	—	—	69	141
Debt securities	—	218	1	—	219	—	232	—	—	232
Other	—	2	—	—	2	—	2	—	—	2
Total	$ 92	$ 272	$ 1	$ 77	$ 442	$ 99	$ 284	$ —	$ 69	$ 452

(a) See Note 10 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2021 or 2020.

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2020 to Dec. 31, 2021, due primarily to benefit payments and increases in discount rates used in actuarial valuations. Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for Xcel Energy are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2021	2020	2021	2020
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,964	$ 3,701	$ 574	$ 547
Service cost	104	95	2	1
Interest cost	104	125	15	18
Plan amendments	5	—	—	—
Actuarial (gain) loss	(94)	328	(41)	50
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	2	1
Benefit payments [(a)]	(365)	(285)	(49)	(51)
Obligation at Dec. 31	$ 3,718	$ 3,964	$ 511	$ 574
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 3,599	$ 3,184	$ 452	$ 449
Actual return on plan assets	305	550	16	35
Employer contributions	131	150	15	11
Plan participants' contributions	—	—	8	8
Benefit payments	(365)	(285)	(49)	(51)
Fair value of plan assets at Dec. 31	$ 3,670	$ 3,599	$ 442	$ 452
Funded status of plans at Dec. 31	$ (48)	$ (365)	$ (69)	$ (122)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Noncurrent assets	$ 19	$ —	$ 33	$ 6
Current liabilities	—	—	(4)	(7)
Noncurrent liabilities	(67)	(365)	(98)	(121)
Net amounts recognized	$ (48)	$ (365)	$ (69)	$ (122)

(a) Includes approximately $197 million in 2021 and $0 million in 2020 of lump-sum benefit payments used in the determination of a settlement charge.

Significant Assumptions Used to Measure Benefit Obligations:	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate for year-end valuation	3.08 %	2.71 %	3.09 %	2.65 %
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	5.30 %	5.50 %
Health care costs trend rate — initial: Post-65	N/A	N/A	4.90 %	5.00 %
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50 %	4.50 %
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50 %	4.50 %
Years until ultimate trend is reached	N/A	N/A	4	5

Accumulated benefit obligation for the pension plan was $3,469 million and $3,693 million as of Dec. 31, 2021 and 2020, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income (expense) in the consolidated statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

(Millions of Dollars)	Pension Benefits 2021	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2021	Postretirement Benefits 2020	Postretirement Benefits 2019
Service cost	$ 104	$ 95	$ 86	$ 2	$ 1	$ 2
Interest cost	104	125	145	15	18	22
Expected return on plan assets	(206)	(208)	(203)	(18)	(19)	(21)
Amortization of prior service credit	(1)	(4)	(5)	(8)	(8)	(10)
Amortization of net loss	107	100	87	5	4	5
Settlement charge (a)	59	—	6	—	—	—
Net periodic pension cost (credit)	167	108	116	(4)	(4)	(2)
Effects of regulation	(46)	9	(1)	2	3	1
Net benefit cost (credit) recognized for financial reporting	$ 121	$ 117	$ 115	$ (2)	$ (1)	$ (1)
Significant Assumptions Used to Measure Costs:						
Discount rate	2.71 %	3.49 %	4.31 %	2.65 %	3.47 %	4.32 %
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	6.49	6.87	6.87	4.10	4.50	4.50

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2021 and 2019, as a result of lump-sum distributions during each plan year, Xcel Energy recorded a total pension settlement charge of $59 million and $6 million, respectively, the majority of which was not recognized due to the effects of regulation. A total of $7 million and $1 million was recorded in the consolidated statements of income in 2021 and 2019, respectively. There were no settlement charges recorded for the qualified pension plans in 2020.

(Millions of Dollars)	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 978	$ 1,333	$ 81	$ 126
Prior service credit	(9)	(11)	(7)	(15)
Total	$ 969	$ 1,322	$ 74	$ 111
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 74	$ 82	$ —	$ —
Noncurrent regulatory assets	846	1,181	90	125
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(19)	(18)
Deferred income taxes	13	15	1	1
Net-of-tax accumulated other comprehensive income	36	44	3	4
Total	$ 969	$ 1,322	$ 74	$ 111
Measurement date	Dec. 31, 2021	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2020

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2019 - 2022 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $50 million in January 2022.
- $131 million in 2021.
- $150 million in 2020.
- $154 million in 2019.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities.

Voluntary postretirement funding contributions:

- Expects to contribute approximately $9 million during 2022.
- $15 million during 2021.
- $11 million during 2020.
- $15 million during 2019.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Domestic and international equity securities	33 %	35 %	15 %	15 %
Long-duration fixed income securities	37	35	—	—
Short-to-intermediate fixed income securities	11	13	71	72
Alternative investments	17	15	8	9
Cash	2	2	6	4
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year.

Plan Amendments —

In 2019, the Pension Protection Act measurement concept was extended beyond 2019 for NSP bargaining terminations and retirements to Dec. 31, 2022.

There were no significant plan amendments made in 2020 which affected the postretirement benefit obligation.

In 2021, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

Projected Benefit Payments

Xcel Energy's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2022	$ 323	$ 42	$ 2	$ 40
2023	257	41	2	39
2024	253	40	2	38
2025	251	38	2	36
2026	245	37	2	35
2027-2031	1,156	165	13	152

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $43 million in 2021, $42 million in 2020 and $39 million in 2019.

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans.

Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

12. Commitments and Contingencies

Legal

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

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's consolidated financial statements. Legal fees are generally expensed as incurred.

Gas Trading Litigation — e prime is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing but has not engaged in natural gas trading or marketing activities since 2003. Multiple lawsuits involving multiple plaintiffs seeking monetary damages were commenced against e prime and its affiliates, including Xcel Energy, between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Cases were all consolidated in the U.S. District Court in Nevada.

One case remains active which includes a multi-district litigation matter consisting of a Wisconsin purported class (Arandell Corp.).

Arandell Corp. — The trial has been vacated and will be rescheduled after the court rules on the pending motions for reconsideration and for class certification. Xcel Energy has concluded that a loss is remote for the remaining lawsuit.

Breckenridge/Colorado — In February 2019, the MDL panel remanded Breckenridge back to the U.S. District Court in Colorado. Settlement of approximately $3 million was reached in February 2021. In July 2021, the settlement was approved.

Rate Matters and Other

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

Minnesota Winter Storm Uri Costs — In its Minnesota jurisdiction, NSP-Minnesota is participating in a contested case regarding the prudency of incremental natural gas costs incurred during Winter Storm Uri. Other parties to the case have recommended significant cost disallowances, and while ultimate resolution of the matter is uncertain, it is reasonably possible that the MPUC could disallow certain deferred costs, resulting in earnings losses. The OAG recommended the MPUC deny recovery of up to $179 million, the largest recommendation among the intervenor positions.

NSP-Minnesota 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 detailing its position that the disallowances recommended by other parties lack any merit in the prudency review given the pertinent facts regarding NSP-Minnesota's actions before, during and after the storm event. An MPUC decision is expected in the summer of 2022.

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

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

In April 2020, the Minnesota Supreme Court denied the insurers' petition for further review, ending the litigation.

In January 2021, the OAG and DOC recommended that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the FCA. NSP-Minnesota subsequently filed its response, asserting that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed $22 million of related costs and no additional refund or disallowance is appropriate. A final decision by the MPUC is pending. A loss related to this matter is deemed remote.

Westmoreland Arbitration — In November 2014, insurers of the Westmoreland Coal Company filed an arbitration demand against NSP-Minnesota, Southern Minnesota Municipal Power Agency and Western Fuels Association, seeking recovery of alleged $36 million of business losses due to a turbine failure at Sherco Unit 3. The Westmoreland insurers claim NSP-Minnesota's invocation of the force majeure clause to stop the supply of coal was improper because the incident was allegedly caused by NSP-Minnesota's failure to conform to industry maintenance standards.

NSP-Minnesota denies the claims asserted by the Westmoreland insurers and believes it properly stopped the supply of coal based upon the force majeure provision. A final hearing has been scheduled for October 2022. The parties are also required to participate in mediation, which has been scheduled for the first quarter of 2022. At this stage of the proceeding, a reasonable estimate of damages or range of damages cannot be determined.

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

In September 2016, the FERC issued an order (Opinion No. 551) granting a 10.32% base ROE effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C Circuit subsequently vacated and remanded Opinion No. 551.

In November 2019, the FERC issued an order (Opinion No. 569), which set the MISO base ROE at 9.88%, effective Sept. 28, 2016 and for the first complaint period. The FERC also dismissed the second complaint. In December 2019, MISO TOs filed a request for rehearing regarding the new ROE methodology announced in Opinion No. 569. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds.

In May 2020, the FERC issued an order (Opinion No. 569-A) which granted rehearing in part to Opinion 569 and further refined the FERC's ROE methodology, most significantly to incorporate the risk premium model (in addition to the discounted cash flow and capital asset pricing models), resulting in a new base ROE of 10.02%, effective Sept. 28, 2016 and for the first complaint period. The FERC also affirmed its decision in Opinion No. 569 to dismiss the second complaint.

In November 2020, the FERC issued an order (Opinion No. 569-B) in response to rehearing requests. The FERC corrected certain inputs to its ROE calculation model, did not change the ROE effective Sept. 28, 2016, and for the first MISO complaint period and upheld its decision to deny refunds for the second complaint period. NSP-Minnesota has recognized a liability for its best estimate of final refunds to customers. Each 10 basis point reduction in ROE for the first complaint period, second complaint period and subsequent period relative to amounts accrued would reduce Xcel Energy's net income by $1 million, $1 million and $2 million, respectively.

The MISO TOs and various parties have filed petitions for review of Opinion Nos. 569, 569-A and 569-B at the D.C. Circuit. Oral arguments were held in late 2021 and a decision is expected by the end of the third quarter of 2022.

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

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In August 2021, the D.C Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates. The timing of these refunds is uncertain.

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. FERC has asked that this appeal be stayed until early 2022, in order to provide FERC with time to issue an order on SPS' April 2018 rehearing request. FERC's order is expected in the first quarter of 2022. The D.C. Circuit appeal may resume after that FERC order is issued.

Wind Operating Commitments — PUCT and NMPRC orders related to the Hale and Sagamore wind projects included certain operating and savings minimums. In general, annual generation must exceed a net capacity factor of 48%. If annual generation is below the guaranteed level, SPS would be obligated to refund an amount equal to foregone PTCs and fuel savings. Additionally, retail customer savings must exceed project costs included in base rates over the first ten years of operations. SPS would be required to refund excess costs, if any, after ten years of operations. As of Dec. 31, 2021, the full-year net capacity factor was 48.4%, resulting in no refund liability for 2021.

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

Comanche Unit 3 Litigation — In February 2021, the joint owners of Comanche Unit 3 (CORE Electric Cooperative, formerly known as Intermountain Rural Electrical Association, and Holy Cross Electric) served PSCo with a notice of claim related to Comanche Unit 3's operation and availability.

In September 2021, CORE Electric Cooperative filed a lawsuit in Colorado state court seeking an unspecified amount of damages. CORE Electric Cooperative alleges PSCo breached ownership agreement terms by failing to operate Comanche Unit 3 in accordance with prudent utility practices. PSCo filed a Motion to Dismiss several of CORE's claims. In January 2022 the Court granted PSCo's Motion to Dismiss CORE's claim for damages for replacement power costs, claims for unjust enrichment and declaratory judgment. CORE's claims for breach of contract, breach of the duty of good faith and fair dealing, and waste remain pending.

In November 2021, PSCo resolved all differences with Holy Cross Electric related to their claim.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process.

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination.

Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to have sent wastes to that site.

Historical MGP, Landfill and Disposal Sites

Xcel Energy is currently investigating, remediating or performing post-closure actions at 16 historical MGP, landfill or other disposal sites across its service territories, excluding sites that are being addressed under current coal ash regulations (see below).

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

Environmental Requirements — Water and Waste

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

Xcel Energy is conducting groundwater sampling and monitoring and implementing assessment of corrective measures at certain CCR landfills and surface impoundments. In NSP-Minnesota, no results above the groundwater protection standards in the rule were identified. In PSCo, increases above background concentrations were detected at four locations. Based on further assessments, PSCo is evaluating options for corrective action at two locations, one of which indicates potential offsite impacts to groundwater. The total cost is uncertain, but could be up to $35 million. PSCo is continuing to assess the financial and regulatory impacts.

In August 2020, the EPA published its final rule to implement closure by April 2021 for all CCR impoundments affected by the August 2018 D.C. Circuit ruling. This final rule required Xcel Energy to expedite closure plans for two impoundments.

In October 2020, NSP-Minnesota completed construction and placed in service a new impoundment to replace the clay lined impoundment. With the new ash pond in service, NSP-Minnesota has initiated closure activities for the existing ash pond at an estimated cost of $4 million. NSP-Minnesota has five years to complete closure activities.

PSCo also built an alternative collection and treatment system to remove the Comanche Station bottom ash pond from service. The total cost of the alternate treatment system is approximately $25 million. PSCo worked expeditiously to meet the April 11, 2021 deadline, but was not able to remove the pond from service until June 18, 2021. PSCo expects to negotiate a compliance order with the EPA addressing the closure deadline as well as other potential issues. PSCo will also now proceed with closure of the pond, at an estimated cost of $3 million.

Closure costs for existing impoundments are included in the calculation of the ARO.

Federal CWA Waters of the U.S. Rule — Xcel Energy is monitoring ongoing changes to the definition of Waters of the U.S. under the CWA. Regardless of which definition is applicable in the states in which we operate, Xcel Energy does not anticipate that compliance costs will be material.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In October 2020, the EPA published a final rule revising the regulations.

The retirement of units affected by the final ELG rule is subject to regulatory approval. The exact total cost of ELG compliance is therefore uncertain but Xcel Energy does not anticipate that compliance costs will be material.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates the likely future cost for complying with impingement and entrainment requirements is approximately $39 million, to be incurred between 2022 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to $192 million. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. The regional haze first planning period requirements developed by Minnesota and Colorado were approved by the EPA in 2012 and implemented by 2014 and 2016, respectively. Texas' first regional haze plan has undergone federal review.

All states are now subject to a second round of regional haze planning/rulemaking, focusing on additional reductions to meet reasonable progress requirements. Any additional impacts to Xcel Energy facilities are expected to be minimal.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the D.C. Circuit that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking. The EPA reaffirmed the rule in August 2020 with minor changes.

The 2020 EPA Action has been challenged. All pending actions could be consolidated and may proceed in the Fifth Circuit or the D.C. Circuit, where a parallel challenge has been filed. The timing of final decisions is unclear.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule referenced above are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule.

Implementation of the NAAQS for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with one exception. The EPA issued final designations, which found the area near the SPS Harrington plant as "unclassifiable." The area near the Harrington plant was monitored for the three years ending in 2019 and the monitoring showed the area to be exceeding the standard.

To address this issue, SPS negotiated an order with the TCEQ providing for the end of coal combustion and the conversion of the Harrington plant to a natural gas fueled facility by Jan. 1, 2025.

Xcel Energy believes compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for Xcel Energy's assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning was $3.3 billion and $2.8 billion for 2021 and 2020, respectively.

Xcel Energy's AROs were as follows:

(Millions of Dollars)	Jan. 1, 2021	Amounts Incurred (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2021 (c)
Electric					
Nuclear	$ 1,957	$ —	$ 99	$ —	$ 2,056
Wind	360	101	17	—	478
Steam, hydro and other production	264	6	10	8	288
Distribution	46	—	1	—	47
Natural gas					
Transmission and distribution	252	—	10	9	271
Miscellaneous	3	—	—	5	8
Common					
Miscellaneous	1	—	—	—	1
Non-utility					
Miscellaneous	1	—	1	—	2
Total liability	$ 2,884	$ 107	$ 138	$ 22	$ 3,151

(a) Amounts incurred related to the wind farms placed in service in 2021 for NSP-Minnesota (Blazing Star 2, Mower and Freeborn) and removal of a utility scale battery asset in NSP-Minnesota.

(b) In 2021, AROs were revised for changes in timing and estimates of cash flows. Revisions in steam, hydro and other production AROs were primarily related to changes in cost estimates for remediation of ash containment facilities. Changes in gas transmission and distribution AROs were primarily related to changes in labor rates coupled with increased gas line mileage and number of services.

(c) There were no ARO amounts settled in 2021.

(Millions of Dollars)	Jan. 1, 2020	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2020
Electric						
Nuclear	$2,068	$ —	$ —	$ 105	$ (216)	$1,957
Steam, hydro and other production	202	—	(5)	9	58	264
Wind	146	149	(3)	8	60	360
Distribution	44	—	—	2	—	46
Natural gas						
Transmission and distribution	236	—	—	10	6	252
Miscellaneous	3	—	—	—	—	3
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,701	$ 149	$ (8)	$ 134	$ (92)	$2,884

(a) Amounts incurred related to the wind farms placed in service in 2020 for NSP-Minnesota (Blazing Star 1, Crowned Ridge 2, Jeffers and Community Wind North), PSCo (Cheyenne Ridge) and SPS (Sagamore).

(b) Amounts settled primarily related to closure of certain ash containment facilities, removal of wind facilities and asbestos abatement projects.

(c) In 2020, AROs were revised for changes in timing and estimates of cash flows. Revisions in the nuclear AROs were driven by reductions in spent fuel cooling time requirements in the nuclear triennial filing coupled with decreasing interest rates. Changes in wind AROs were driven by new dismantling studies. Revisions in steam, hydro and other production AROs were primarily related to changes in cost estimates for remediation of ash containment facilities.

Indeterminate AROs — Other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2021. Therefore, an ARO was not recorded for these facilities.

Nuclear

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $13.5 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.0 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to $138 million per reactor-incident for each of its three reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $21 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.8 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350 million, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage.

NSP-Minnesota could be subject to annual maximum assessments of $11 million for business interruption insurance and $33 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 47 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life. A CON for additional storage at the Monticello site has been filed with the MPUC, to support possible life extension. NSP-Minnesota expects a decision by year-end 2023.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. The cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%.

Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota had $3.3 billion of assets held in external decommissioning trusts at Dec. 31, 2021. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements as an ARO.

	Regulatory Basis	
(Millions of Dollars)	**2021**	**2020**
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	1,006	844
Estimated decommissioning cost obligation (in current dollars)	4,018	3,856
Effect of escalating costs to payment date	7,187	7,349
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 1.96% and 1.64% for 2021 and 2020, respectively)	(4,651)	(4,181)
Discounted decommissioning cost obligation	$ 6,554	$ 7,024
Assets held in external decommissioning trust	$ 3,256	$ 2,777
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	3,298	4,247

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	**2021**	**2020**
Discounted decommissioning cost obligation - regulated basis	$ 6,554	$ 7,024
Differences in discount rate and market risk premium	(2,209)	(2,628)
O&M costs not included for GAAP	(1,584)	(1,734)
ARO differences between 2020 and 2014 cost studies	(705)	(705)
Nuclear production decommissioning ARO - GAAP	$ 2,056	$ 1,957

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	**2021**	**2020**	**2019**
Annual decommissioning recorded as depreciation expense: [(a)] [(b)]	$ 22	$ 20	$ 20

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2021, 2020 and 2019 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2017 nuclear decommissioning filing, effective Jan. 1, 2019, has been approved by the MPUC. In March 2020, the MPUC approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2021. In December 2020, the MPUC verbally approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2022. In December 2021, NSP-Minnesota submitted a Petition for approval of the 2022 - 2024 Nuclear Decommissioning Study and Assumptions. Contemplated but not proposed in this filing, was the 10-year extension of the license to operate the Monticello Plant, moving the planned retirement date from 2030 to 2040. The 2019 Preferred Integrated Resource Plan Supplement does include a 10-year extension of the license. On Feb. 8, 2022, the MPUC approved the 10-year extension.

Leases

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

ROU assets represent Xcel Energy's rights to use leased assets. The present value of future operating lease payments is recognized in other current liabilities and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of Xcel Energy's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the applicable Xcel Energy subsidiary's estimated incremental borrowing rate (weighted average of 4.0%). Xcel Energy has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	**Dec. 31, 2021**	**Dec. 31, 2020**
PPAs	$ 1,656	$ 1,650
Other	225	212
Gross operating lease ROU assets	1,881	1,862
Accumulated amortization	(590)	(372)
Net operating lease ROU assets	$ 1,291	$ 1,490

ROU assets for finance leases are included in other noncurrent assets, and the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities.

Xcel Energy's most significant finance lease activities are related to WYCO, a joint venture with CIG, to develop and lease natural gas pipeline, storage and compression facilities. Xcel Energy Inc. has a 50% ownership interest in WYCO. WYCO leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage and transportation services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service and Front Range pipeline arrangements with CIG and WYCO, respectively, as finance leases. Xcel Energy Inc. eliminates 50% of the finance lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

Finance lease ROU assets:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Gas storage facilities	$ 201	$ 201
Gas pipeline	21	21
Gross finance lease ROU assets	222	222
Accumulated amortization	(97)	(90)
Net finance lease ROU assets	$ 125	$ 132

Components of lease expense:

(Millions of Dollars)	2021	2020	2019
Operating leases			
PPA capacity payments	$ 251	$ 238	$ 221
Other operating leases [a]	36	26	34
Total operating lease expense [b]	$ 287	$ 264	$ 255
Finance leases			
Amortization of ROU assets	$ 7	$ 7	$ 6
Interest expense on lease liability	17	18	19
Total finance lease expense	$ 24	$ 25	$ 25

(a) Includes short-term lease expense of $5 million for 2021, 2020 and 2019.

(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating and finance leases as of Dec. 31, 2021:

(Millions of Dollars)	PPA [a] [b] Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [c]
2022	$ 229	$ 27	$ 256	$ 12
2023	221	26	247	12
2024	209	22	231	12
2025	189	16	205	10
2026	146	12	158	9
Thereafter	416	81	497	187
Total minimum obligation	1,410	184	1,594	242
Interest component of obligation	(209)	(34)	(243)	(170)
Present value of minimum obligation	$ 1,201	150	1,351	72
Less current portion			(205)	(3)
Noncurrent operating and finance lease liabilities			$ 1,146	$ 69
Weighted-average remaining lease term in years			8.9	36.1

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2039.

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

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2033, contain minimum energy purchase commitments. Total energy payments on those contracts were $149 million, $112 million and $102 million in 2021, 2020 and 2019, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $69 million, $75 million and $86 million in 2021, 2020 and 2019, respectively.

Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

At Dec. 31, 2021, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [a]
2022	$ 75	$ 165
2023	77	169
2024	72	174
2025	29	53
2026	12	10
Thereafter	12	38
Total	$ 277	$ 609

(a) Excludes contingent energy payments for renewable energy PPAs.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire between 2022 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2021:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2022	$ 620	$ 89	$ 477	$ 292
2023	233	109	75	224
2024	147	82	4	172
2025	29	119	—	156
2026	31	29	—	149
Thereafter	34	309	—	571
Total	$ 1,094	$ 737	$ 556	$ 1,564

VIEs

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. Xcel Energy has determined that certain IPPs are VIEs. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance.

The utility subsidiaries had approximately 4,062 MW of capacity under long-term PPAs at both Dec. 31, 2021 and 2020 with entities that have been determined to be VIEs. These agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO Inc. under contracts that will expire in December 2022. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs.

SPS has determined that TUCO is a VIE, however it has concluded that SPS is not the primary beneficiary of TUCO because it does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing partnerships to be VIEs primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not align with the partners' proportional equity ownership.

Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance. Therefore, Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements. Xcel Energy's risk of loss for these partnerships is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be, provided to the limited partnerships by Eloigne or NSP-Wisconsin.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Current assets	$ 7	$ 7
Property, plant and equipment, net	37	38
Other noncurrent assets	1	1
Total assets	$ 45	$ 46
Current liabilities	$ 7	$ 8
Mortgages and other long-term debt payable	27	25
Other noncurrent liabilities	1	1
Total liabilities	$ 35	$ 34

Other

Technology Agreements — Xcel Energy has several contracts for information technology services that extend through 2022. The contracts are cancelable, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $103 million, $110 million and $101 million associated with these contracts in 2021, 2020 and 2019, respectively.

Committed minimum payments under these obligations are $15 million in 2022.

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

As of Dec. 31, 2021 and 2020, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements. Guarantees and bond indemnities issued and outstanding for Xcel Energy were $60 million and $62 million at Dec. 31, 2021 and 2020 respectively.

Other Indemnification Agreements — Xcel Energy Inc. and its subsidiaries provide indemnifications through various contracts. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

13. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31:

	2021		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (85)	$ (56)	$ (141)
Other comprehensive loss before reclassifications (net of taxes of $1 and $—, respectively)	4	—	4
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $2 and $—, respectively)	6 (a)	—	6
Amortization of net actuarial loss (net of taxes of $— and $3, respectively)	—	8 (b)	8
Net current period other comprehensive income	10	8	18
Accumulated other comprehensive loss at Dec. 31	$ (75)	$ (48)	$ (123)

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

(Millions of Dollars)	2020 Gains and Losses on Cash Flow Hedges		2020 Defined Benefit Pension and Postretirement Items		2020 Total
Accumulated other comprehensive loss at Jan. 1	$ (80)		$ (61)		$ (141)
Other comprehensive loss before reclassifications (net of taxes of $(3) and $(2), respectively)	(10)		(5)		(15)
Losses reclassified from net accumulated other comprehensive loss:					
Interest rate derivatives (net of taxes of $2 and $—, respectively)	5	(a)	—		5
Amortization of net actuarial loss (net of taxes of $— and $3, respectively)	—		10	(b)	10
Net current period other comprehensive (loss) income	(5)		5		—
Accumulated other comprehensive loss at Dec. 31	$ (85)		$ (56)		$ (141)

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

14. Segment Information

Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided, including the regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments:

- **Regulated Electric** — The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations.
- **Regulated Natural Gas** — The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Xcel Energy also presents All Other, which includes operating segments with revenues below the necessary quantitative thresholds. Those operating segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel, investments in rental housing projects that qualify for low-income housing tax credits and the operations of MEC until July 2020.

Xcel Energy had equity method investments of $208 million and $165 million as of Dec. 31, 2021 and 2020, respectively, included in the natural gas utility and all other segments.

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

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

Xcel Energy's segment information:

(Millions of Dollars)	2021	2020	2019
Regulated Electric			
Operating revenues — external	$ 11,205	$ 9,802	$ 9,575
Intersegment revenue	2	2	1
Total revenues	$ 11,207	$ 9,804	$ 9,576
Depreciation and amortization	1,855	1,673	1,535
Interest charges and financing costs	568	534	500
Income tax (benefit) expense	(96)	1	125
Net income	1,478	1,407	1,288
Regulated Natural Gas			
Operating revenues — external	$ 2,132	$ 1,636	$ 1,868
Intersegment revenue	2	1	2
Total revenues	$ 2,134	$ 1,637	$ 1,870
Depreciation and amortization	254	252	219
Interest charges and financing costs	75	71	69
Income tax expense	54	17	48
Net income	231	190	195
All Other			
Total revenues	$ 94	$ 88	$ 86
Depreciation and amortization	12	23	11
Interest charges and financing costs	173	193	167
Income tax benefit	(28)	(24)	(45)
Net loss	(112)	(124)	(111)
Consolidated Total			
Total revenues	$ 13,435	$ 11,529	$ 11,532
Reconciling eliminations	(4)	(3)	(3)
Total operating revenues	$ 13,431	$ 11,526	$ 11,529
Depreciation and amortization	2,121	1,948	1,765
Interest charges and financing costs	816	798	736
Income tax (benefit) expense	(70)	(6)	128
Net income	1,597	1,473	1,372

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of Dec. 31, 2021, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter ended Dec. 31, 2021 that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level.

During the year and in preparation for issuing its report for the year ended Dec. 31, 2021 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in Xcel Energy's Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

ITEM 9B — OTHER INFORMATION

None.

ITEM 9C — DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10 — DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is expected to occur on April 5, 2022, incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

ITEM 11 — EXECUTIVE COMPENSATION

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item (aggregate fees billed to us by our principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34)) is contained in Xcel Energy Inc.'s Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

ITEM 15 — EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

1	Consolidated Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2021.
	Report of Independent Registered Public Accounting Firm — Financial Statements and Internal Controls Over Financial Reporting
	Consolidated Statements of Income — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
	Consolidated Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
	Consolidated Statements of Cash Flows — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
	Consolidated Balance Sheets — As of Dec. 31, 2021 and 2020.
	Consolidated Statements of Common Stockholders' Equity — For each of the three years ended Dec. 31, 2021, 2020, and 2019.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2021, 2020, and 2019.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc. Form 8-K dated May 16, 2012	3.01
3.02*	Bylaws of Xcel Energy Inc. as Amended on April 3, 2020	Xcel Energy Inc. Form 8-K dated April 3, 2020	3.01
4.01*	Description of Securities	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	4.01

4.02*	Indenture dated Dec. 1, 2000 between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	4.01
4.03*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 6, 2006	4.01
4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	4.01
4.05*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	4.03
4.06*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	4.01
4.07*	Supplemental Indenture No. 8, dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 1, 2015	4.01
4.08*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	4.01
4.09*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 25, 2018	4.01
4.10*	Supplemental Indenture No. 12, dated as of Nov. 7, 2019 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating 2.60% Senior Notes, Series due Dec 1. 2029 and 3.50% Senior Notes, Series due Dec. 1, 2049	Xcel Energy Inc. Form 8-K dated Nov. 7, 2019	4.01
4.11*	Supplemental Indenture No. 13, dated as of April 1, 2020 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association as Trustee creating $600 million principal amount of 3.40% Senior Notes, Series due June 1, 2030	Xcel Energy Inc. Form 8-K dated April 1, 2020	4.01
4.12*	Supplemental Indenture No. 14, dated as of Sept. 25, 2020 between Xcel Energy Inc. and Wells Fargo Bank, National Association as Trustee, creating $500 million principal amount of 0.50% Senior Notes, Series due Oct. 15, 2023	Xcel Energy Inc. Form 8-K dated Sept. 25, 2020	4.01
4.13*	Supplemental Indenture No. 15, dated as of Nov. 3, 2021 between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $500 million principal amount of 1.75% Senior Notes, Series due March 15, 2027 and $300 million principal amount of 2.35% Senior Notes, Series due Nov. 15, 2031	Xcel Energy Inc. Form 8-K dated Nov. 3, 2021	4.01
10.01*	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.05
10.03*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.18
10.04*+	Fifth Amendment to Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	10.01
10.05*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	10.01
10.06*+	Eighth Amendment to Exhibit 10.02 dated March 31, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2020	10.02
10.07*+	Ninth Amendment to Exhibit 10.02 dated May 22, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2020	10.01
10.08*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.17
10.09*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	Appendix A
10.10*+	First Amendment to Exhibit 10.09 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	10.01
10.11*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	10.08
10.12*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.07
10.13*+	First Amendment to Exhibit 10.12 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.17
10.14*+	Second Amendment to Exhibit 10.12 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	10.22
10.15*+	Third Amendment to Exhibit 10.12 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	10.01
10.16*+	Fourth Amendment to Exhibit 10.12 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	10.1
10.17*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.34
10.18*+	Form of Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan for Awards of Restricted Stock Units and/or Performance Share Units	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.35
10.19*+	Form of Award Agreement for Restricted Stock Units and/or Performance Share Units under the Xcel Energy Inc. 2015 Omnibus Incentive Plan for awards since 2020	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	10.32
10.20*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	Appendix A
10.21*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	10.02
10.22*+	Summary of Non-Employee Director Compensation, effective as of Oct. 1, 2021	Xcel Energy Inc. Form 10-Q for the quarter ended September 30, 2021	10.01
10.23*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.36
10.24*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	H-1

10.25*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.01
10.26*	364-Day Term Loan Agreement dated as of February 18, 2021 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and U.S. Bank National Association, as Administrative Agent.	Xcel Energy Inc. Form 8-K dated February 18, 2021	10.01
10.27*+	Form of Award Agreement for Retention-Based Restricted Stock Units under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated December 10, 2021	10.01
NSP-Minnesota			
4.14*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(3)
4.15*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due July 1, 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.11
4.16*	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due March 1, 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.12
4.17*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.51
4.18*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(7)
4.19*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.63
4.20*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	4.01
4.21*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	4.01
4.22*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	4.01
4.23*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and the Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	4.01
4.24*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.95% First Mortgage Bonds, Series due Aug. 15, 2015 and $250 principal amount of 4.85% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	4.01
4.25*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	4.01
4.26*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due May 15, 2023	NSP-Minnesota Form 8-K dated May 20, 2013	4.01
4.27*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044	NSP-Minnesota Form 8-K dated May 13, 2014	4.01
4.28*	Supplemental Trust Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and the Bank of New York Mellon Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due Aug. 15, 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due Aug. 15, 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	4.01
4.29*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and the Bank of NY Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.60% First Mortgage Bonds, Series due May 15, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	4.01
4.31*	Supplemental Trust Indenture dated as of Sept. 1, 2019 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 2.90% First Mortgage Bonds, Series due March 1, 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	4.01
4.32*	Supplemental Indenture dated as of June 8, 2020 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $700 million principal amount of 2.60% First Mortgage Bonds, Series due June 1, 2051	NSP-Minnesota 8-K dated June 15, 2020	4.01
4.33*	Supplemental Indenture dated as of March 1, 2021 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $425 million principal amount of 2.25% First Mortgage Bonds, Series due April 1, 2031 and $425 million principal amount of 3.20% First Mortgage Bonds, Series due April 1, 2052	NSP-Minnesota 8-K dated March 30, 2021	4.01
10.28*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.29*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.02
NSP-Wisconsin			
4.34*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust Company, providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(c)(3)
4.35*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	4.01

4.36*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	4.01
4.37*	Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.70% First Mortgage Bonds, Series due Oct. 1, 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	4.01
4.38*	Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30% First Mortgage Bonds, Series due June 1, 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	4.01
4.39*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.75% First Mortgage Bonds, Series due Dec. 1, 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	4.01
4.40*	Supplemental Indenture dated as of Sept. 1, 2018 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 4.20% First Mortgage Bonds, Series due Sept. 1, 2048	NSP-Wisconsin Form 8-K dated Sept. 12, 2018	4.01
4.41*	Supplemental Indenture dated as of May 18, 2020 between NSP-Wisconsin and U.S. Bank National Association, as Trustee, creating $100 million principal amount of 3.05% First Mortgage Bonds, Series due May 1, 2051	NSP-Wisconsin Form 8-K dated May 26, 2020	4.01
4.42*	Supplemental Indenture dated as of July 19, 2021 between NSP-Wisconsin and U.S. Bank National Association, as Trustee, creating $100 million principal amount of 2.82% First Mortgage Bonds, Series due May 1, 2051	NSP-Wisconsin Form 8-K dated July 20, 2021	4.01
10.30*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.31*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.05
10.32*	Bond Purchase Agreement, dated July 19, 2021, among NSP-Wisconsin and the several purchasers listed in Schedule B thereto	NSP-Wisconsin Form 8-K dated July 20, 2021	1.01
PSCo			
4.43*	Indenture, dated as of Oct. 1, 1993 between PSCo and Morgan Guaranty Trust Company of New York, as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(d)(3)
4.44*	Supplemental Indenture, dated Aug. 1, 2007 between PSCo and U.S. Bank Trust National Association, as successor Trustee	PSCo Form 8-K dated Aug. 8, 2007	4.01
4.45*	Supplemental Indenture dated as of Aug. 1, 2008 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80% First Mortgage Bonds, Series due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series due 2038	PSCo Form 8-K dated Aug. 6, 2008	4.01
4.46*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75% First Mortgage Bonds, Series due 2041	PSCo Form 8-K dated Aug. 9, 2011	4.01
4.47*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series due 2042	PSCo Form 8-K dated Sept. 11, 2012	4.01
4.48*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50% First Mortgage Bonds, Series due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series due 2043	PSCo Form 8-K dated March 26, 2013	4.01
4.49*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30% First Mortgage Bonds, Series due 2044	PSCo Form 8-K dated March 10, 2014	4.01
4.50*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.90% First Mortgage Bonds, Series due 2025	PSCo Form 8-K dated May 12, 2015	4.01
4.51*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 3.55% First Mortgage Bonds, Series due 2046	PSCo Form 8-K dated June 13, 2016	4.01
4.52*	Supplemental Indenture dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.80% First Mortgage Bonds, Series due 2047	PSCo Form 8-K dated June 19, 2017	4.01
4.53*	Supplemental Indenture dated as of June 1, 2018 between PSCo and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70% First Mortgage Bonds, Series due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series due 2048	PSCo Form 8-K dated June 21, 2018	4.01
4.54*	Supplemental Indenture dated as of March 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 4.05% First Mortgage Bonds, Series due 2049	PSCo Form 8-K dated March 13, 2019	4.01
4.55*	Supplemental Indenture dated as of Aug. 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $550 million principal amount of 3.20% First Mortgage Bonds, Series due 2050	PSCo Form 8-K dated August 13, 2019	4.01
4.56*	Supplemental Indenture dated as of May 1, 2020 between PSCo and U.S. Bank National Association, as successor Trustee, creating $375 million principal of 2.70% First Mortgage Bonds, Series No. 35 due 2051 and $375 million principal amount of 1.90% First Mortgage Bonds, Series No. 36 due 2031	PSCo Form 8-K dated May 15, 2020	4.01
4.57*	Supplemental Indenture dated as of February 1, 2021 between PSCo and U.S. Bank National Association, as successor Trustee, creating $750 million principal of 1.875% First Mortgage Bonds, Series No. 37 due 2031	PSCo Form 8-K dated March 1, 2021	4.01
10.33*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	99.02
10.34*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.03
SPS			
4.58*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	99.2
4.59*	Supplemental Indenture dated Oct. 1, 2003 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6% due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	4.04
4.60*	Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee, creating $200 million principal amount of 5.6% Series E Notes due 2016 and $250 million principal amount of 6% Series F Notes due 2036	SPS Form 8-K dated Oct. 3, 2006	4.01

4.61*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	4.01

4.62*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series due 2041	SPS Form 8-K dated Aug. 10, 2011	4.02
4.63*	Supplemental Indenture dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	SPS Form 8-K dated June 9, 2014	4.02
4.64*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series due 2046	SPS Form 8-K dated Aug. 12, 2016	4.02
4.65*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series due 2047	SPS Form 8-K dated Aug 9. 2017	4.02
4.66*	Supplemental Indenture dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 4.40% First Mortgage Bonds, Series due 2048	SPS Form 8-K dated Nov. 5, 2018	4.02
4.67*	Supplemental Indenture dated as of June 1, 2019 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.75% First Mortgage Bonds, Series due 2049	SPS Form 8-K dated June 18, 2019	4.02
4.68*	Supplemental Indenture No. 8, dated as of May 1, 2020 between SPS and U.S. Bank National Association, as Trustee, creating $600 million principal amount of 3.15% First Mortgage Bonds, Series due 2050	SPS Form 8-K dated May 18, 2020	4.02
10.35*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.04

Xcel Energy Inc.	
21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm
24.01	Powers of Attorney
31.01	Principal Executive Officer’s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.02	Principal Financial Officer’s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH	Inline XBRL Schema
101.CAL	Inline XBRL Calculation
101.DEF	Inline XBRL Definition
101.LAB	Inline XBRL Label
101.PRE	Inline XBRL Presentation
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

SCHEDULE I

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2021	2020	2019
Income			
Equity earnings of subsidiaries	$ 1,744	$ 1,646	$ 1,505
Total income	1,744	1,646	1,505
Expenses and other deductions			
Operating expenses	21	43	23
Other income	3	(4)	(9)
Interest charges and financing costs	173	198	173
Total expenses and other deductions	197	237	187
Income before income taxes	1,547	1,409	1,318
Income tax benefit	(50)	(64)	(54)
Net income	$ 1,597	$ 1,473	$ 1,372
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $ 1, $1 and $1, respectively	$ 8	$ 5	$ 3
Derivative instruments, net of tax of $3, $(1) and $(7), respectively	10	(5)	(20)
Other comprehensive income (loss)	18	—	(17)
Comprehensive income	$ 1,615	$ 1,473	$ 1,355
Weighted average common shares outstanding:			
Basic	539	527	519
Diluted	540	528	520
Earnings per average common share:			
Basic	$ 2.96	$ 2.79	$ 2.64
Diluted	2.96	2.79	2.64

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2021	2020	2019
Operating activities			
Net cash provided by operating activities	$ 1,147	$ 2,377	$ 1,389
Investing activities			
Capital contributions to subsidiaries	(1,661)	(2,553)	(1,594)
Net return (investments) in the utility money pool	57	(18)	39
Other, net	—	(1)	—
Net cash used in investing activities	(1,604)	(2,572)	(1,555)
Financing activities			
Proceeds (repayment of) from short-term borrowings, net	638	(500)	12
Proceeds from issuance of long-term debt	791	1,089	1,120
Repayment of long-term debt	(400)	(300)	(550)
Proceeds from issuance of common stock	366	727	458
Repurchase of common stock	—	(4)	—
Dividends paid	(935)	(856)	(791)
Other	(16)	(17)	(14)
Net cash provided by financing activities	444	139	235
Net change in cash, cash equivalents, and restricted cash	(13)	(56)	69
Cash, cash equivalents and restricted cash at beginning of period	14	70	1
Cash, cash equivalents and restricted cash at end of period	$ 1	$ 14	$ 70

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2021	2020
Assets		
Cash and cash equivalents	$ 1	$ 14
Accounts receivable from subsidiaries	430	424
Other current assets	6	6
Total current assets	437	444
Investment in subsidiaries	21,167	19,102
Other assets	71	40
Total other assets	21,238	19,142
Total assets	$ 21,675	$ 19,586
Liabilities and Equity		
Current portion of long-term debt	—	400
Dividends payable	249	231
Short-term debt	638	—
Other current liabilities	29	21
Total current liabilities	916	652
Other liabilities	10	17
Total other liabilities	10	17
Commitments and contingencies		
Capitalization		
Long-term debt	5,137	4,342
Common stockholders' equity	15,612	14,575
Total capitalization	20,749	18,917
Total liabilities and equity	$ 21,675	$ 19,586

See Notes to Condensed Financial Statements

Notes to Condensed Financial Statements

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and other comprehensive income in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Guarantees and Indemnifications

Xcel Energy Inc. provides guarantees and bond indemnities under specified agreements or transactions, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. limit the exposure to a maximum stated amount. As of Dec. 31, 2021 and 2020, Xcel Energy Inc. had no assets held as collateral related to guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding as of Dec. 31, 2021:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of loan for Hiawatha Collegiate High School [(a)]	Xcel Energy Inc.	$ 1	—	[(c)]
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries [(b)]	Xcel Energy Inc.	59	[(e)]	[(d)]

(a) The term of this guarantee expires the earlier of 2024 or full repayment of the loan.
(b) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.
(c) Nonperformance and/or nonpayment.
(d) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.
(e) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. provides indemnifications through contracts entered into in the normal course of business. Indemnifications are primarily against adverse litigation outcomes in connection with underwriting agreements, breaches of representations and warranties, including corporate existence, transaction authorization and certain income tax matters. Obligations under these agreements may be limited in terms of duration or amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Related Party Transactions — Xcel Energy Inc. presents related party receivables net of payables. Accounts receivable net of payables with affiliates at Dec. 31:

(Millions of Dollars)	2021	2020
NSP-Minnesota	$ 104	$ 81
NSP-Wisconsin	25	9
PSCo	91	98
SPS	58	55
Xcel Energy Services Inc.	125	159
Other subsidiaries of Xcel Energy Inc.	27	22
	$ 430	$ 424

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $1,344 million, $2,527 million and $2,987 million for the years ended Dec. 31, 2021, 2020 and 2019, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

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

Money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2021
Loan outstanding at period end	$ —
Average loan outstanding	—
Maximum loan outstanding	—
Weighted average interest rate, computed on a daily basis	N/A
Weighted average interest rate at end of period	N/A
Money pool interest income	$ —

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2021	Year Ended Dec. 31, 2020	Year Ended Dec. 31, 2019
Loan outstanding at period end	$ —	$ 57	$ 39
Average loan outstanding	16	104	47
Maximum loan outstanding	439	350	250
Weighted average interest rate, computed on a daily basis	0.08 %	0.60 %	2.15 %
Weighted average interest rate at end of period	N/A	0.07 %	1.63
Money pool interest income	$ —	$ 1	$ 1

See notes to the consolidated financial statements in Part II, Item 8.

SCHEDULE II

Xcel Energy Inc. and Subsidiaries Valuation and Qualifying Accounts Years Ended Dec. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2021	2020	2019	2021	2020	2019
Balance at Jan. 1	$ 79	$ 55	$ 55	$ 64	$ 67	$ 79
Additions charged to costs and expenses	60	60	42	5	6	9
Additions charged to other accounts	14 [(a)]	12 [(a)]	16 [(a)]	—	—	—
Deductions from reserves	(47) [(b)]	(48) [(b)]	(58) [(b)]	(5) [(d)]	(9) [(c)]	(21) [(d)]
Balance at Dec. 31	$ 106	$ 79	$ 55	$ 64	$ 64	$ 67

(a) Recovery of amounts previously written-off.
(b) Deductions related primarily to bad debt write-offs.
(c) Primarily the reduction of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability forecasted to be used prior to expiration along with valuation allowances that expired.
(d) Primarily reductions to valuation allowances due to additional NOLs and tax credits forecasted to be used prior to expiration.

ITEM 16 — FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 23, 2022	By:	/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Senior Vice President, Controller (Principal Accounting Officer)
*	Lynn Casey	Director
*	Netha N. Johnson	Director
*	Patricia L. Kampling	Director
*	George J. Kehl	Director
*	Richard T. O’Brien	Director
*	Charles Pardee	Director
*	Christopher J. Policinski	Director
*	James Prokopanko	Director
*	David A. Westerlund	Director
*	Kim Williams	Director
*	Timothy V. Wolf	Director
*	Daniel Yohannes	Director
*By:	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Attorney-in-Fact