Northern States Power Company
Before the
Minnesota Public Utilities Commission

Application for Authority to
Increase Gas Rates in Minnesota
Docket No. G002/GR-23-413

November 1, 2023

Volume 3

Required Information

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REQUIRED INFORMATION
Volume 3

REQUIRED INFORMATION
Volume 3 (continued)

Northern States Power Company
Gas Operations - State of Minnesota

DEFINITIONS

As required by Minnesota Rules, Part 7825.3800, the following information shall be supplied as a part of the utility's notice of a change in rates. Information requirements Parts 7825.3900, 7825.4000, item A; 7825.4100, item A; 7825.4200, item A; and 7825.4300, items A and B, as defined herein, shall be supplied by all gas and electric utilities and all other information requirements prescribed by Parts 7825.3800 to 7825.4400 shall be supplied where applicable to the utility.

For purposes of complying with the Financial Information requirements prescribed by Parts 7825.3900, 7825.4000, 7825.4100, 7825.4200, 7825.4300, 7825.4400, and 7825.4500, the following definitions have been used by Northern States Power Company (Minnesota) in this filing:

Most Recent Fiscal Year

This information represents actual financial information for the calendar year ended December 31, 2022.

Projected Fiscal Year

The projected fiscal year is the fiscal year immediately following the most recent fiscal year (2023). For the purposes of this filing, this information represents projected financial information for the calendar year ending December 31, 2023.

Proposed Test Year

The proposed test year information represents the budgets developed for the 2024 calendar year and includes the effects of ratemaking adjustments.

Unadjusted Financial Information

Unadjusted financial information consists of financial data before ratemaking adjustments.

Northern States Power Company
Gas Operations - State of Minnesota

DEFINITIONS (Continued)

Adjusted Financial Information

Adjusted financial information consists of financial data prepared with ratemaking adjustments included.

Note on Rounding:

The cost of service study on which these supporting schedules are based rounds numbers to the nearest thousand for display purposes. However, the subtotals and subsequent totals in the cost of service study are based on actual values resulting in occasional differences in the totals displayed and the sum of the line items. These supporting schedules were prepared using individual line items with subtotals and totals calculated on each schedule. This results in occasional differences between the subtotals and totals on the cost of service study and those on supporting schedules.

JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
(PART 7825.3900)

A jurisdictional financial summary schedule as required by parts 7825.3800 and 7825.3900 shall be filed showing:

A. the proposed rate base, operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the test year;

B. the actual unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the most recent fiscal year; and

C. the projected unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income under present rates, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the projected fiscal year.

Northern States Power Company
Gas Operations - State of Minnesota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule A-1

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2022 (A)	Adjusted (1) Projected Fiscal Year 2023 (B)	Adjusted (1) Proposed Test Year 2024 (C)
1	Average Rate Base	$1,017,964	$1,165,341	$1,267,863
2	Operating Income	$50,818	$56,725	$50,099
3	Allowance for funds used during construction	$3,200	$2,317	$2,677
4	Total Available for Return	$54,018	$59,042	$52,776
5	Overall Rate of Return (Line 4 / Line 1)	5.31%	5.07%	4.16%
6	Required Rate of Return	7.36%	7.44%	7.48%
7	Required Operating Income (Line 1 x Line 6)	$74,922	$86,701	$94,836
8	Income Deficiency (Line 7 - Line 4)	$20,904	$27,660	$42,060
9	Gross Revenue Conversion Factor	1.403351	1.403351	1.403351
10	Revenue Deficiency (Line 8 x Line 9)	$29,336	$38,816	$59,026
11	Retail Related Revenues Under Present Rates			$617,806
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)			9.55%

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule A-2

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2022 (A)	Unadjusted (1) Projected Fiscal Year 2023 (B)	Unadjusted (1) Proposed Test Year 2024 (C)
1	Average Rate Base	$1,021,670	$1,168,684	$1,285,033
2	Operating Income	$49,289	$55,799	$47,776
3	Allowance for funds used during construction	$3,200	$2,317	$2,677
4	Total Available for Return	$52,489	$58,116	$50,453
5	Overall Rate of Return (Line 4 / Line 1)	5.14%	4.97%	3.93%
6	Required Rate of Return	7.36%	7.44%	7.48%
7	Required Operating Income (Line 1 x Line 6)	$75,195	$86,950	$96,120
8	Income Deficiency (Line 7 - Line 4)	$22,706	$28,834	$45,667
9	Gross Revenue Conversion Factor	1.403351	1.403351	1.403351
10	Revenue Deficiency (Line 8 x Line 9)	$31,865	$40,464	$64,087
11	Retail Related Revenues Under Present Rates			$621,192
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)			10.32%

(1) Revenues and expenses for riders have been included where applicable

RATE BASE SCHEDULES
(PART 7825.4000)

The following rate base schedules as required by parts 7825.3800 and 7825.4000 shall be filed:

A. A rate base summary schedule by major rate base component (e.g. plant in service, construction work in progress, and plant held for future use) showing the proposed rate base, the unadjusted average rate base for the most recent fiscal year and unadjusted average rate base for the projected fiscal year. The totals for this schedule shall agree with the rate base amounts included in the financial summary.

B. A comparison of total utility and Minnesota jurisdictional rate base amounts by detailed rate base component showing:

   1) total utility and the proposed jurisdictional rate base amounts for the test year including the adjustments, if any, used in determining the proposed rate base;

   2) the unadjusted average total utility and jurisdictional rate base amounts for the most recent fiscal year and the projected fiscal year.

C. Adjustment schedules, if any, showing the title, purpose, and description and the summary calculations of each adjustment used in determining the proposed jurisdictional rate base.

D. A summary by rate base component of the assumptions made and the approaches used in determining average unadjusted rate base for the projected fiscal year. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.

E. For multi-jurisdictional utilities only, a summary by rate base component of the jurisdictional allocation factors used in allocating the total utility rate base amount to the Minnesota jurisdiction. This summary shall be supported by a schedule showing for each allocation factor the total utility and jurisdictional statistics used in determining the proposed rate base and the Minnesota jurisdictional rate base for the most recent fiscal year and the projected fiscal year.

Northern States Power Company **Docket No. G002/GR-23-413**
Gas Operations - State of Minnesota **Financial Information**
RATE BASE SCHEDULES **Schedule A-1**
RATE BASE SUMMARY
($000's)

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2022 (A)	Adjusted (1) Projected Fiscal Year 2023 (B)	Adjusted (1) Proposed Test Year 2024 (C)
1	Utility Plant in Service	$1,810,858	$2,019,700	$2,187,742
2				
3	Less: Reserve for Depreciation	$684,961	$730,469	$785,328
4				
5	Net Utility Plant in Service	$1,125,897	$1,289,232	$1,402,415
6				
7	Utility Plant Held for Future Use	0	0	0
8				
9	Construction Work in Progress	53,382	36,357	34,124
10				
11	Less: Accumulated Deferred Income Taxes	205,940	208,797	214,540
12				
13	Other Rate Base Items			
14	Cash Working Capital	(13,602)	(7,497)	(9,998)
15	Materials and Supplies	$1,786	$2,318	$2,318
16	Gas In Storage	44,180	43,755	43,755
17	Non-Plant Assets & Liabilities	10,052	8,153	7,968
18	Prepayments	71	(195)	(195)
19	Customer Advances	(161)	(153)	(153)
20	Other Working Capital	2,299	2,168	2,168
21	Regulatory Amortizations	0	0	0
22				
23	Total Other Rate Base Items	$44,626	$48,549	$45,864
24				
25	Total Average Rate Base	$1,017,964	$1,165,341	$1,267,863

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
RATE BASE SCHEDULES
RATE BASE SUMMARY
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule A-2

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2022 (A)	Unadjusted (1) Projected Fiscal Year 2023 (B)	Unadjusted (1) Proposed Test Year 2024 (C)
1	Utility Plant in Service	$1,815,490	$2,024,270	$2,209,344
2				
3	Less: Reserve for Depreciation	$685,232	$730,807	$784,714
4				
5	Net Utility Plant in Service	$1,130,258	$1,293,462	$1,424,630
6				
7	Utility Plant Held for Future Use	0	0	0
8				
9	Construction Work in Progress	53,382	36,357	34,124
10				
11	Less: Accumulated Deferred Income Taxes	206,310	209,236	215,469
12				
13	Other Rate Base Items			
14	Cash Working Capital	(13,886)	(7,946)	(14,114)
15	Materials and Supplies	$1,786	$2,318	$2,318
16	Gas In Storage	44,180	43,755	43,755
17	Non-Plant Assets & Liabilities	10,052	8,153	7,968
18	Prepayments	71	(195)	(195)
19	Customer Advances	(161)	(153)	(153)
20	Other Working Capital	2,299	2,168	2,168
21	Regulatory Amortizations	0	0	0
22				
23	Total Other Rate Base Items	$44,342	$48,100	$41,748
24				
25	Total Average Rate Base	$1,021,670	$1,168,684	$1,285,033

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule B-1

		Proposed Test Year 2024					
		Total Utility			Minnesota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (1) (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (1) (F) (D) + (E)
	Gas Plant as Booked						
1	Gas Manufactured Plant	$86,718	$0	$86,718	$75,274	$0	$75,274
2	Gas Storage	108,434	0	108,434	94,123	0	94,123
3	Gas Transmission	144,750	(6,320)	138,430	140,744	(6,320)	134,424
4	Gas Distribution	1,841,105	(15,282)	1,825,823	1,626,921	(15,282)	1,611,639
5	General	168,375	0	168,375	148,766	0	148,766
6	Common	139,797	0	139,797	123,517	0	123,517
7	TOTAL Utility Plant in Service	$2,489,179	($21,602)	$2,467,577	$2,209,344	($21,602)	$2,187,742
8							
9	Reserve for Depreciation						
10	Gas Manufactured Plant	$22,875	$0	$22,875	$19,856	$0	$19,856
11	Gas Storage	$52,880	0	$52,880	45,901	0	45,901
12	Gas Transmission	$34,848	(163)	$34,686	33,030	(163)	32,868
13	Gas Distribution	$630,097	2,037	$632,135	563,315	2,037	565,353
14	General	$68,965	(1,427)	$67,538	60,933	(1,261)	59,672
15	Common	69,808	0	69,808	61,678	0	61,678
16	TOTAL Reserve for Depreciation	$879,473	$447	$879,920	$784,714	$613	$785,328
17							
18	Net Utility Plant in Service						
19	Gas Manufactured Plant	$63,844	$0	$63,844	$55,418	$0	$55,418
20	Gas Storage	55,554	0	55,554	48,223	0	48,223
21	Gas Transmission	109,902	(6,157)	103,744	107,713	(6,157)	101,556
22	Gas Distribution	1,211,008	(17,319)	1,193,689	1,063,605	(17,319)	1,046,286
23	General	99,410	1,427	100,837	87,833	1,261	89,094
24	Common	69,989	0	69,989	61,838	0	61,838
25	Net Utility Plant in Service	$1,609,706	($22,049)	$1,587,657	$1,424,630	($22,215)	$1,402,415
26							
27	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
28							
29	Construction Work in Progress	$38,717	$0	$38,717	$34,124	$0	$34,124
30							
31	Less: Accumulated Deferred Income T	$238,680	($882)	$237,797	$215,469	($930)	$214,540
32							
33	Other Rate Base Items:						
34	Cash Working Capital	($15,137)	$4,193	($10,945)	($14,114)	$4,116	($9,998)
35	Materials and Supplies	$2,624	$0	$2,624	$2,318	$0	$2,318
36	Gas In Storage	$49,763	0	$49,763	$43,755	0	43,755
37	Non-Plant Assets & Liabilities	$9,017	0	$9,017	$7,968	0	7,968
38	Prepayments	($1,755)	0	($1,755)	($195)	0	(195)
39	Customer Advances	($173)	0	($173)	($153)	0	(153)
40	Other Working Capital	$2,455	0	$2,455	$2,168	0	2,168
41	Regulatory Amortizations	0	985	985	0	0	0
42							
43	Total Other Rate Base Items	$46,793	$5,178	$51,971	$41,748	$4,116	$45,864
44							
45	Total Average Rate Base	$1,456,537	($15,989)	$1,440,548	$1,285,033	($17,170)	$1,267,863

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule B-1 (2)

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2022 Total Utility (A)	Minnesota Jurisdiction (B)	Adjusted (1) Projected Fiscal Year 2023 Total Utility (C)	Minnesota Jurisdiction (D)
	Gas Plant as Booked				
1	Gas Manufactured Plant	$41,298	$36,091	$65,367	$56,741
2	Gas Storage	78,525	68,625	92,346	80,159
3	Gas Transmission	118,093	114,162	129,266	125,293
4	Gas Distribution	1,592,606	1,418,043	1,724,686	1,531,094
5	General	102,597	90,855	136,440	120,550
6	Common	93,819	83,082	119,816	105,863
7	TOTAL Utility Plant in Service	$2,026,938	$1,810,858	$2,267,922	$2,019,700
8					
9	Reserve for Depreciation				
10	Gas Manufactured Plant	$16,210	$14,166	$19,142	$16,615
11	Gas Storage	50,301	43,959	51,090	44,348
12	Gas Transmission	31,489	29,782	33,126	31,360
13	Gas Distribution	574,109	513,581	600,976	537,490
14	General	48,435	42,891	56,671	50,071
15	Common	45,826	40,581	57,252	50,584
16	TOTAL Reserve for Depreciation	$766,370	$684,961	$818,257	$730,469
17					
18	Net Utility Plant in Service				
19	Gas Manufactured Plant	$25,088	$21,925	$46,226	$40,125
20	Gas Storage	28,224	24,665	41,256	35,811
21	Gas Transmission	86,603	84,380	96,140	93,933
22	Gas Distribution	1,018,497	904,462	1,123,710	993,605
23	General	54,163	47,964	79,769	70,479
24	Common	47,993	42,500	62,565	55,279
25	Net Utility Plant in Service	$1,260,568	$1,125,897	$1,449,665	$1,289,232
26					
27	Utility Plant Held for Future Use	$0	$0	$0	$0
28					
29	Construction Work in Progress	$60,187	$53,382	$41,339	$36,357
30					
31	Less: Accumulated Deferred Income Taxes	$227,020	$205,940	$230,863	$208,797
32					
33	Other Rate Base Items:				
34	Cash Working Capital	($14,423)	($13,602)	($7,634)	($7,497)
35	Materials and Supplies	2,017	1,786	$2,624	2,318
36	Gas In Storage	50,382	44,180	$49,763	43,755
37	Non-Plant Assets & Liabilities	11,347	10,052	$9,223	8,153
38	Prepayments	(1,394)	71	($1,755)	(195)
39	Customer Advances	(182)	(161)	($173)	(153)
40	Other Working Capital	2,603	2,299	$2,455	2,168
41	Regulatory Amortizations	1,105	0	1,045	0
42					
43	Total Other Rate Base Items	$51,455	$44,626	$55,548	$48,549
44					
45	Total Average Rate Base	$1,145,190	$1,017,964	$1,315,689	$1,165,341

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule B-2

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2022 Total Utility (A)	Minnesota Jurisdiction (B)	Unadjusted (1) Projected Fiscal Year 2023 Total Utility (C)	Minnesota Jurisdiction (D)
	Gas Plant as Booked				
1	Gas Manufactured Plant	$41,298	$36,091	$65,367	$56,741
2	Gas Storage	78,525	68,625	92,346	80,159
3	Gas Transmission	122,725	118,794	133,897	129,925
4	Gas Distribution	1,592,606	1,418,043	1,724,624	1,531,032
5	General	102,597	90,855	136,440	120,550
6	Common	93,819	83,082	119,816	105,863
7	TOTAL Utility Plant in Service	$2,031,570	$1,815,490	$2,272,491	$2,024,270
8					
9	Reserve for Depreciation				
10	Gas Manufactured Plant	$16,210	$14,166	$19,142	$16,615
11	Gas Storage	50,301	43,959	51,090	44,348
12	Gas Transmission	31,760	30,053	33,471	31,705
13	Gas Distribution	574,109	513,581	600,969	537,483
14	General	48,435	42,891	56,671	50,071
15	Common	45,826	40,581	57,252	50,584
16	TOTAL Reserve for Depreciation	$766,641	$685,232	$818,596	$730,807
17					
18	Net Utility Plant in Service				
19	Gas Manufactured Plant	$25,088	$21,925	$46,226	$40,125
20	Gas Storage	28,224	24,665	41,256	35,811
21	Gas Transmission	90,964	88,741	100,426	98,220
22	Gas Distribution	1,018,497	904,462	1,123,654	993,548
23	General	54,163	47,964	79,769	70,479
24	Common	47,993	42,500	62,565	55,279
25	Net Utility Plant in Service	$1,264,929	$1,130,258	$1,453,896	$1,293,462
26					
27	Utility Plant Held for Future Use	$0	$0	$0	$0
28					
29	Construction Work in Progress	$60,187	$53,382	$41,339	$36,357
30					
31	Less: Accumulated Deferred Income Taxes	$227,390	$206,310	$231,302	$209,236
32					
33	Other Rate Base Items:				
34	Cash Working Capital	($14,748)	($13,886)	($8,142)	($7,946)
35	Materials and Supplies	2,017	1,786	2,624	2,318
36	Gas In Storage	50,382	44,180	49,763	43,755
37	Non-Plant Assets & Liabilities	11,347	10,052	9,223	8,153
38	Prepayments	(1,394)	71	(1,755)	(195)
39	Customer Advances	(182)	(161)	(173)	(153)
40	Other Working Capital	2,603	2,299	2,455	2,168
41	Regulatory Amortizations	1,105	0	0	0
42					
43	Total Other Rate Base Items	$51,130	$44,342	$53,995	$48,100
44					
45	Total Average Rate Base	$1,148,856	$1,021,670	$1,317,928	$1,168,684

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2024 Test Year walk forward to Final Adjusted Test Year
($000s)

Docket No. G002/GR-23-413
Financial Information
Schedule C.1 - 2024 Test Year

Line No.		Bridge - Unadjusted				Adjustments			Rider Removals	Secondary Calculations		
		ADIT Prorate for IRS	Cash Working Capital	Base	Total Unadjusted	Black Dog Pipeline	Depreciation Study	New Business CIAC	GUIC Rider Removal	ADIT Prorate for IRS	Cash Working Capital	Total
1												
2	Plant as booked											
3	Gas Manufactured Plant			75,274	75,274							75,274
4	Gas Storage			94,123	94,123							94,123
5	Gas Transmission			140,744	140,744	(4,632)			(1,688)			134,424
6	Gas Distribution			1,626,921	1,626,921			(29)	(15,253)			1,611,639
7	General			148,766	148,766							148,766
8	Common			123,517	123,517							123,517
9	Total Utility Plant in Service			2,209,344	2,209,344	(4,632)		(29)	(16,942)			2,187,742
10												
11	Reserve for Depreciation											
12	Gas Manufactured Plant			19,856	19,856							19,856
13	Gas Storage			45,901	45,901							45,901
14	Gas Transmission			33,030	33,030	(423)	108		153			32,868
15	Gas Distribution			563,315	563,315		1,231	(1)	807			565,353
16	General			60,933	60,933		(1,261)					59,672
17	Common			61,678	61,678							61,678
18	Total Reserve for Depreciation			784,714	784,714	(423)	78	(1)	960			785,328
19												
20	Net Utility Plant											
21	Gas Manufactured Plant			55,418	55,418							55,418
22	Gas Storage			48,223	48,223							48,223
23	Gas Transmission			107,713	107,713	(4,208)	(108)		(1,841)			101,556
24	Gas Distribution			1,063,605	1,063,605		(1,231)	(27)	(16,061)			1,046,286
25	General			87,833	87,833		1,261					89,094
26	Common			61,838	61,838							61,838
27	Net Utility Plant in Service			1,424,630	1,424,630	(4,208)	(78)	(27)	(17,902)			1,402,415
28												
29	Utility Plant Held for Future Use											
30												
31	Construction Work in Progress			34,124	34,124							34,124
32												
33	Less: Accumulated Deferred Income Taxes	(252)		215,721	215,469	(490)	(9)	(0)	(468)	37		214,540
34												
35	Other Rate Base Items											
36	Cash Working Capital		(14,114)		(14,114)						4,116	(9,998)
37	Materials and Supplies			2,318	2,318							2,318
38	Fuel Inventory			43,755	43,755							43,755
39	Non Plant Assets and Liabilities			7,968	7,968							7,968
40	Customer Advances			(195)	(195)							(195)
41	Customer Deposits			(153)	(153)							(153)
42	Prepayments			2,168	2,168							2,168
43	Regulatory Amortizations											
44	Total Other Rate Base		(14,114)	55,862	41,748						4,116	45,864
45												
46	Total Average Rate Base	252	(14,114)	1,298,895	1,285,033	(3,718)	(69)	(27)	(17,434)	(37)	4,116	1,267,863

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2024 Test Year walk forward to Final Adjusted Test Year

Docket No. G002/GR-23-413
Financial Information
Schedule C - 2024 Test Year

ADJUSTMENT TYPE	ADJUSTMENT	ADJUSTMENT DESCRIPTION
Adjustment	Black Dog Pipeline	Remove costs that exceed main and service extension justifications
Adjustment	Depreciation Study	Reflects the modified depreciation rates, remaining life updates, and modified salvage rates in the test year
Adjustment	New Business CIAC	Remove instances where new business CIAC that would have been justified was not collected
Rider Removals	GUIC Rider Removal	Removes costs and revenues related to items being recovered in rate riders

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2023 Bridge Year walk forward to Adjusted Bridge Year

Docket No. G002/GR-23-413
Financial Information
Schedule C.2 - 2023 Bridge Year

($000s)

		Bridge - Unadjusted				Adjustments		Rider Removals	Secondary Calculations		
		ADIT Prorate for IRS	Cash Working Capital	Base	Total Unadjusted	Black Dog Pipeline	New Business CIAC	GUIC Rider Removal	ADIT Prorate for IRS	Cash Working Capital	Total
1											
2	Plant as booked										
3	Gas Manufactured Plant			56,741	56,741						56,741
4	Gas Storage			80,159	80,159						80,159
5	Gas Transmission			129,925	129,925	(4,632)					125,293
6	Gas Distribution			1,531,032	1,531,032		(14)	77			1,531,094
7	General			120,550	120,550						120,550
8	Common			105,863	105,863						105,863
9	Total Utility Plant in Service			2,024,270	2,024,270	(4,632)	(14)	77			2,019,700
10											
11	Reserve for Depreciation										
12	Production										
13	Transmission										
14	Gas Manufactured Plant			16,615	16,615						16,615
15	Gas Storage			44,348	44,348						44,348
16	Gas Transmission			31,705	31,705	(345)					31,360
17	Gas Distribution			537,483	537,483		(0)	7			537,490
18	General			50,071	50,071						50,071
19	Common			50,584	50,584						50,584
20	Total Reserve for Depreciation			730,807	730,807	(345)	(0)	7			730,469
21											
22	Net Utility Plant										
23	Production										
24	Transmission										
25	Distribution										
26	Gas Manufactured Plant			40,125	40,125						40,125
27	Gas Storage			35,811	35,811						35,811
28	Gas Transmission			98,220	98,220	(4,287)					93,933
29	Gas Distribution			993,548	993,548		(14)	70			993,605
30	General			70,479	70,479						70,479
31	Common			55,279	55,279						55,279
32	Net Utility Plant in Service			1,293,462	1,293,462	(4,287)	(14)	70			1,289,232
33											
34	Utility Plant Held for Future Use										
35											
36	Construction Work in Progress			36,357	36,357						36,357
37											
38	Less: Accumulated Deferred Income Taxes	(207)		209,443	209,236	(434)	(0)	(7)	2		208,797
39											

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2023 Bridge Year walk forward to Adjusted Bridge Year

Docket No. G002/GR-23-413
Financial Information
Schedule C.2 - 2023 Bridge Year

($000s)

		Bridge - Unadjusted				Adjustments		Rider Removals	Secondary Calculations		
		ADIT Prorate for IRS	Cash Working Capital	Base	Total Unadjusted	Black Dog Pipeline	New Business CIAC	GUIC Rider Removal	ADIT Prorate for IRS	Cash Working Capital	Total
40	Other Rate Base Items										
41	Cash Working Capital		(7,946)		(7,946)					450	(7,497)
42	Materials and Supplies			2,318	2,318						2,318
43	Fuel Inventory			43,755	43,755						43,755
44	Non Plant Assets and Liabilities			8,153	8,153						8,153
45	Customer Advances			(195)	(195)						(195)
46	Customer Deposits			(153)	(153)						(153)
47	Prepayments			2,168	2,168						2,168
48	Regulatory Amortizations										
49	Total Other Rate Base		(7,946)	56,046	48,100					450	48,549
50											
51	Total Average Rate Base	207	(7,946)	1,176,423	1,168,684	(3,852)	(14)	77	(2)	450	1,165,341

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2023 Bridge Year walk forward to Final Adjusted Bridge Year

Docket No. G002/GR-23-413
Financial Information
Schedule C.2 - 2023 Bridge Year

ADJUSTMENT TYPE	ADJUSTMENT	ADJUSTMENT DESCRIPTION
Adjustment	Black Dog Pipeline	Remove costs that exceed main and service extension justifications
Adjustment	New Business CIAC	Remove instances where new business CIAC that would have been justified was not collected
Rider Removals	GUIC Rider Removal	Removes costs and revenues related to items being recovered in rate riders

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2022 Actual Year walk forward to Adjusted Actual Year

Docket No. G002/GR-23-413
Financial Information
Schedule C.3 - 2022 Actual Year

($000s)

Line No.		Bridge - Unadjusted					Adjustments	Secondary Calculations	Total
		ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Base	Total Unadjusted	Black Dog Pipeline	Cash Working Capital	
1									
2	Plant as booked								
3	Gas Manufactured Plant				36,091	36,091			36,091
4	Gas Storage				68,625	68,625			68,625
5	Gas Transmission				118,794	118,794	(4,632)		114,162
6	Gas Distribution				1,418,043	1,418,043			1,418,043
7	General				90,855	90,855			90,855
8	Common				83,082	83,082			83,082
9	Total Utility Plant in Service				1,815,490	1,815,490	(4,632)		1,810,858
10									
11	Reserve for Depreciation								
12	Gas Manufactured Plant				14,166	14,166			14,166
13	Gas Storage				43,959	43,959			43,959
14	Gas Transmission				30,053	30,053	(271)		29,782
15	Gas Distribution				513,581	513,581			513,581
16	General				42,891	42,891			42,891
17	Common				40,581	40,581			40,581
18	Total Reserve for Depreciation				685,232	685,232	(271)		684,961
19									
20	Net Utility Plant								
21	Gas Manufactured Plant				21,925	21,925			21,925
22	Gas Storage				24,665	24,665			24,665
23	Gas Transmission				88,741	88,741	(4,361)		84,380
24	Gas Distribution				904,462	904,462			904,462
25	General				47,964	47,964			47,964
26	Common				42,500	42,500			42,500
27	Net Utility Plant in Service				1,130,258	1,130,258	(4,361)		1,125,897
28									
29	Utility Plant Held for Future Use								
30									
31	Construction Work in Progress				53,382	53,382			53,382
32									
33	Less: Accumulated Deferred Income Taxes			658	205,653	206,310	(371)		205,940
34									

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2022 Actual Year walk forward to Adjusted Actual Year
($000s)

Docket No. G002/GR-23-413
Financial Information
Schedule C.3 - 2022 Actual Year

Line No.		Bridge - Unadjusted					Adjustments	Secondary Calculations	Total
		ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Base	Total Unadjusted	Black Dog Pipeline	Cash Working Capital	
35	Other Rate Base Items								
36	Cash Working Capital		(13,886)			(13,886)		284	(13,602)
37	Materials and Supplies				1,786	1,786			1,786
38	Fuel Inventory				44,180	44,180			44,180
39	Non Plant Assets and Liabilities				10,052	10,052			10,052
40	Customer Advances				71	71			71
41	Customer Deposits				(161)	(161)			(161)
42	Prepayments				2,299	2,299			2,299
43	Regulatory Amortizations								
44	Total Other Rate Base		(13,886)		58,227	44,342		284	44,626
45									
46	Total Average Rate Base		(13,886)	(658)	1,036,214	1,021,670	(3,990)	284	1,017,964

Northern States Power Company
State of Minnesota Gas Jurisdiction
RATE BASE ADJUSTMENTS SCHEDULE
Unadjusted 2022 Actual Year walk forward to Final Adjusted Actual Year

Docket No. G002/GR-23-413
Financial Information
Schedule C.3 - 2022 Actual Year

ADJUSTMENT TYPE	ADJUSTMENT	ADJUSTMENT DESCRIPTION
Adjustment	Black Dog Pipeline	Remove costs that exceed main and service extension justifications

PLANT IN SERVICE

Plant in Service represents facilities that are used and useful in providing utility service, including facilities currently in service, capital projects completed but not classified, and property held for future use. Plant in Service represents historical and projected additions and retirements to NSP's gas utility. Plant additions represent plant that is already in use (capitalized) or will become useful in the future, but has not become part of the official plant accounting records of the Company. Plant retirements represent plant taken out of service.

The gas utility plant is functionalized according to its use into the following areas: production, storage, transmission, distribution, general, and common use. Plant in Service investment for each function is calculated using a beginning-of-year and end-of-year average. The historical plant balances for the gas utility correspond directly to the Company's books and records. Actual additions and retirements through June 30, 2023, are used as a starting point for the projected year-end amounts for both the projected 2023 fiscal year and the 2024 proposed test year. Projected additions and retirements are then developed using the Company's construction budget. Additions and retirements are developed on a monthly basis and are used to compute the Plant in Service amounts for the projected fiscal year for the gas utility.

ACCUMULATED PROVISION FOR DEPRECIATION

The Accumulated Provision for Depreciation represents the recovery of the amount invested in Plant in Service. The balances in this account include the historical and projected retirements and net salvage of NSP's gas utility Plant in Service by function.

Accumulated Provision for Depreciation is functionalized on the same basis as Plant in Service. Accumulated Provision for Depreciation for the projected year is calculated using a beginning-of-year and end-of-year average. The historical and projected Accumulated Provisions for Depreciation are based upon the annual straight line depreciation rates that are developed for each functional class and certified by the Minnesota Public Utilities Commission.

HELD FOR FUTURE USE

Property Held for Future Use includes land, land rights and plant acquired but never used in providing utility service, and plant removed from service but held pending its reuse in the future under a definite plan of action.

Property Held for Future Use balances are shown by function. The projected fiscal year amount reflects an average of the beginning-of-year and end-of-year amounts.

CONSTRUCTION WORK IN PROGRESS

Construction Work in Progress consists of projects that have not been completed, or have been completed, but have not yet been classified to Plant in Service.

Construction Work in Progress balances are shown by function. The projected fiscal year amount reflects an average of the beginning-of-year and end-of-year amounts. When a project has been completed and is ready to be capitalized to Plant in Service, the capital budget system reflects the lag that actually occurs before a project is recorded as Plant in Service.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes represent the accumulated annual net provision for deferred income taxes relating to liberalized depreciation, repair allowance, and other capitalized items including property tax, payroll tax, sales tax, and pensions. Accumulated Deferred Income Taxes reflect timing differences between book and tax depreciation lives, and other non-plant book/tax timing differences.

The balance in this account is functionalized on the same basis as Plant in Service. NSP maintains its plant investments, both historical and projected, at a level of detail such that an accurate calculation of book depreciation and tax depreciation may be made. The Accumulated Deferred Income Taxes for the projected year are calculated using a beginning-of-year and end-of-year average and are deducted from net Plant in Service.

CASH WORKING CAPITAL

Cash Working Capital represents the cash investment requirement to pay for operating expenses, to maintain compensating cash balances, and to provide for other cash needs, such as employee advances.

Cash Working Capital for the projected fiscal year is determined using a lead/lag study on projected fiscal year revenues (assuming proposed level of rates) and projected fiscal year expenses. The revenue lead versus the expense lag is measured and the difference is applied to the projected fiscal year expense categories.

MATERIALS AND SUPPLIES

Materials and Supplies reflect balances from gas transmission and distribution and meter accounts. Materials and Supplies are used to maintain and repair existing plant and in the construction of new facilities.

The amount included in Materials and Supplies for the projected year represents a thirteen-month average of the projected balances in the above-mentioned accounts.

GAS IN STORAGE

Gas in Storage represents the Liquid Petroleum Gas (LPG), Liquid Natural Gas (LNG), and natural gas in underground storage. Gas in Storage is used to meet peak fuel requirements of customers in excess of contract pipeline entitlements and as a base source of supply.

Northern States Power Company
Gas Operations - State of Minnesota
RATE BASE SCHEDULES
ASSUMPTIONS AND APPROACHES USED
IN DETERMINING AVERAGE UNADJUSTED
RATE BASE FOR THE PROJECTED FISCAL YEAR

Docket No. G002/GR-23-413
Financial Information
Schedule D
Page 4 of 5

NON-PLANT ASSETS AND LIABILITIES

The balance in this account represents accrued liabilities for:
Pension - The amount of internal pension accrual which is an increase to rate base.
Accrued Vacation Reserve - This item represents the liability for earned vacation not taken. The amount is a decrease to rate base.
SFAS 106 - This item represents the test year average post-retirement benefits expense (excluding pension costs) to be accrued and collected in accordance with SFAS 106, but not paid. Until the benefits are actually paid or remitted to a plan trustee, the accrued expenses represent a source of cash provided by the Company's customers, and as such, are reflected as a reduction to rate base.
SFAS 112 - This item represents the test year average post-employment expense to be accrued and collected in accordance with SFAS 112, but not paid. Until the benefits are actually paid, the accrued expenses represent as source of cash and thus reflected as a reduction of rate base.
All Other Adjustments - This item represents the test year average of all other non-plant assets and liabilities not specifically identified above. The amount represents a source of cash and is being reflected as a reduction of rate base.

PREPAYMENTS

Prepayments include payments made in prior periods for such items as prepaid insurance, postage, rent, gas reservation fee, gas imbalance fee, regulatory fee, VEBA trust, workers compensation and taxes.

Prepayments for the projected year are based upon the most recent thirteen-month historical period.

NEW BUSINESS CIAC

This item represents removing expenses that will be charged as a contribution in aid of construction based on a proposed change in rate design.

CUSTOMER ADVANCES/DEPOSITS

This liability account represents a non-investor source of capital. The amount in this account represents balances that may be refunded to customers who have advanced funds as a deposit or for construction of facilities beyond NSP's service extension policy. Customer advances are a negative adjustment to rate base.

OTHER WORKING CAPITAL

Other Working Capital consist of various asset and liability accounts that have been allocated or assigned to the gas utility. The inclusion of these items reflects additional sources (or uses) of investor and non-investor supplied funds.

Other Working Capital included in the test year reflect the thirteen-month average of historical balances for these items.

Northern States Power Company
Gas Utility - State of Minnesota
Rate Base Jurisdictional Allocation Factors

Financial Information
Schedule E, Page 1 of 2

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine Minnesota jurisdictional rate base amounts for all of the years presented in these schedules.	
	The following allocation factors are used to compute North Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress:	
1	Production (LPG Production)	Design Day Demand
2	Storage (LNG Storage)	Design Day Demand
3	General	
	Production	Design Day Demand
	Other	Customers
4	Common	
	Production	Design Day Demand
	Other	Customers
	In addition, the following allocation factors are used to compute Minnesota jurisdictional amounts:	
5	Other Rate Base:	
	Materials & Supplies	Customers
	Gas in Storage	Design Day Demand
	Gas in Storage-Underground	Load Dispatch
	Non-Plant Assets & Liabilities	Customers and Load Dispatch
	Prepayments	Customers

Northern States Power Company
Gas Utility - State of Minnesota
Rate Base Jurisdictional Allocation Factors

Financial Information
Schedule E, Page 2 of 2

		Most Recent Fiscal Year 2022			Projected Fiscal Year 2023			Proposed Test Year 2024 (Adjusted & Unadjusted)		
Line No.	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor
1	**Design Day Demand**	874,955	764,644	**87.3923%**	897,827	779,336	**86.8025%**	897,827	779,336	**86.8025%**
2	Design Day Demand	874,955	764,644	87.3923%	897,827	779,336	86.8025%	897,827	779,336	86.8025%
	MCF	128,216,697	112,875,569	88.0350%	133,116,539	118,778,662	89.2291%	133,116,539	118,778,662	89.2291%
	Load Dispatch			**87.7137%**			**88.0158%**			**88.0158%**
3	**Customers**	542,836	480,711	**88.5554%**	555,347	490,673	**88.3543%**	555,347	490,673	**88.3543%**

OPERATING INCOME SCHEDULES
(PART 7825.4100)

The following operating income schedules as required by parts 7825.3800 and 7825.4100 shall be filed:

A. A summary schedule of jurisdictional operating income statements which reflect proposed test year operating income, and unadjusted jurisdictional operating income for the most recent fiscal year and the projected fiscal year calculated using present rates.

B. For multi-jurisdictional utilities only, a schedule showing the comparison of total utility and unadjusted jurisdictional operating income statement for the test year, for the most recent fiscal year and the projected fiscal year. In addition, the schedule shall provide the proposed adjustments, if any, to jurisdictional operating income for the test year together with the proposed operating income statement.

C. For investor-owned utilities only, a summary schedule showing the computation of total utility and allocated Minnesota jurisdictional federal and state income tax expense and deferred income taxes for the test year, the most recent fiscal year, and the projected fiscal year. This summary schedule shall be supported by a detailed schedule, showing the development of the combined federal and state income tax rates.

D. A summary schedule of adjustments, if any, to jurisdictional test year operating income and detailed schedules for each adjustment providing an adjustment title, purpose and description of the adjustment, and summary calculations.

E. A schedule summarizing the assumptions made and the approaches used in projecting each major element of operating income. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.

OPERATING INCOME SCHEDULES (Continued)
(PART 7825.4100)

F. For multi-jurisdictional utilities only, a schedule providing, by operating income element, the factor or factors used in allocating total utility operating income to Minnesota jurisdiction. This schedule shall be supported by a schedule which sets forth the statistics used in determining each jurisdictional allocation factor for the test year, the most recent fiscal year, and the projected fiscal year.

Northern States Power Company | **Docket No. G002/GR-23-413**
Gas Operations - State of Minnesota | **Financial Information**
OPERATING INCOME SCHEDULES | **Schedule A-1**
JURISDICTIONAL STATEMENT OF OPERATING INCOME
($000's)

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2022 (A)	Adjusted (1) Projected Fiscal Year 2023 (B)	Adjusted (1) Proposed Test Year 2024 (C)
	Operating Revenues			
1	Retail	$861,496	$693,216	$610,396
2	Weather Impact Net Margin Adjustment	-	-	-
3	Other Operating	11,191	10,063	11,640
4	**Total Operating Revenues**	$872,687	$703,279	$622,037
5				
6	**Expenses**			
7	Operating Expenses:			
8	Purchased Gas	$636,394	$447,735	$350,434
9	Gas Production and Storage	8,594	8,949	7,927
10	Gas Transmission	1,021	746	623
11	Gas Distribution	35,757	37,179	39,553
12	Customer Accounting	11,909	11,870	12,887
13	Customer Service and Information	29,517	20,747	29,720
14	Sales, Econ Dev, & Other	64	(45)	50
15	Administrative and General	23,081	24,573	27,550
16	Total Operating Expenses	$746,338	$551,754	$468,744
17				
18	Depreciation	$52,940	$63,352	$73,521
19	Amortizations	($9,638)	($156)	$926
20				
21	Taxes:			
22	Property	$19,769	$18,490	$18,633
23	Deferred Income Tax & ITC	4,130	5,610	5,681
24	Federal & State Income Tax	5,758	4,439	1,006
25	Payroll & Other	2,572	3,065	3,427
26	Total Taxes	$32,229	$31,604	$28,747
27				
28	**Total Expenses**	$821,869	$646,554	$571,938
29				
30	AFUDC	$3,200	$2,317	$2,677
31				
32	**Total Operating Income**	$54,018	$59,042	$52,776

(1) Revenues and expenses for riders have been included where applicable
Note: Revenues reflect calendar month sales.

Northern States Power Company | **Docket No. G002/GR-23-413**
Gas Operations - State of Minnesota | **Financial Information**
OPERATING INCOME SCHEDULES | **Schedule A-2**
JURISDICTIONAL STATEMENT OF OPERATING INCOME
($000's)

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2022 (A)	Unadjusted (1) Projected Fiscal Year 2023 (B)	Unadjusted (1) Proposed Test Year 2024 (C)
	Operating Revenues			
1	Retail	$861,496	$693,825	$613,782
2	Weather Impact Net Margin Adjustment	-	-	-
3	Other Operating	11,191	10,063	10,496
4	**Total Operating Revenues**	$872,687	$703,888	$624,278
5				
6	**Expenses**			
7	Operating Expenses:			
8	Purchased Gas	$636,394	$447,735	$350,434
9	Gas Production and Storage	8,594	8,949	7,927
10	Gas Transmission	1,021	1,299	2,169
11	Gas Distribution	35,757	37,252	39,446
12	Customer Accounting	11,909	11,870	12,641
13	Customer Service and Information	29,522	20,748	29,720
14	Sales, Econ Dev, & Other	57	(54)	38
15	Administrative and General	25,179	25,665	28,741
16	Total Operating Expenses	$748,434	$553,463	$471,116
17				
18	Depreciation	$53,010	$63,423	$73,715
19	Amortizations	($9,638)	$0	$0
20				
21	Taxes:			
22	Property	$19,769	$18,484	$22,686
23	Deferred Income Tax & ITC	4,199	5,677	6,666
24	Federal & State Income Tax	5,040	3,974	(1,112)
25	Payroll & Other	2,584	3,068	3,431
26	Total Taxes	$31,592	$31,203	$31,671
27				
28	**Total Expenses**	$823,398	$648,089	$576,502
29				
30	AFUDC	$3,200	$2,317	$2,677
31				
32	**Total Operating Income**	$52,489	$58,116	$50,453

Note: Revenues reflect calendar month sales.

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule B-1

Line No.	Description	Adjusted (1) Most Recent Fiscal 2022 Total Utility (A)	Adjusted (1) Most Recent Fiscal 2022 Minnesota Jurisdiction (B)	Adjusted (1) Projected Fiscal 2023 Total Utility (C)	Adjusted (1) Projected Fiscal 2023 Minnesota Jurisdiction (D)	Adjusted (1) Proposed Test Year 2024 Total Utility (E)	Adjusted (1) Proposed Test Year 2024 Minnesota Jurisdiction (F)
	Operating Revenues						
1	Retail	$999,804	$861,496	$803,619	$693,216	$691,362	$610,396
2	Weather Impact Net Margin Adjustment	0	0	0	0	0	0
3	Other Operating	13,440	11,191	$10,434	$10,063	$12,110	$11,640
4	**Total Operating Revenues**	$1,013,244	$872,687	$814,053	$703,279	$703,472	$622,037
5							
6	**Expenses**						
7	Operating Expenses:						
8	Purchased Gas	$746,193	$636,394	$525,746	$447,735	$400,150	$350,434
9	Gas Production and Storage	10,223	8,594	11,041	8,949	8,978	7,927
10	Gas Transmission	1,164	1,021	850	746	714	623
11	Gas Distribution	41,017	35,757	42,636	37,179	44,835	39,553
12	Customer Accounting	13,350	11,909	13,379	11,870	14,205	12,887
13	Customer Service and Information	29,657	29,517	20,876	20,747	29,872	29,720
14	Sales, Econ Dev, & Other	74	64	(52)	(45)	55	50
15	Administrative and General	26,235	23,081	27,962	24,573	31,019	27,550
16	Total Operating Expenses	$867,915	$746,338	$642,439	$551,754	$529,827	$468,744
17							
18	Depreciation	$59,513	$52,940	$71,399	$63,352	$82,832	$73,521
19	Amortizations	($9,578)	($9,638)	$27	($156)	$1,230	$926
20							
21	Taxes:						
22	Property	$21,259	19,769	$20,281	$18,490	$20,653	$18,633
23	Deferred Income Tax & ITC	5,237	4,130	$6,713	$5,610	$6,978	$5,681
24	Federal & State Income Tax	6,729	5,758	$5,036	$4,439	$844	$1,006
25	Payroll & Other	2,911	2,572	3,459	3,065	3,823	3,427
26	Total Taxes	$36,135	$32,229	$35,489	$31,604	$32,298	$28,747
27							
28	**Total Expenses**	$953,985	$821,869	$749,354	$646,554	$646,187	$571,938
29							
30	Allowance for Funds Used During Constru	$3,467	$3,200	$2,697	$2,317	$2,995	$2,677
31							
32	**Total Operating Income**	$62,726	$54,018	$67,397	$59,042	$60,280	$52,776

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule B-2

Line No.	Description	Unadjusted (1) Most Recent Fiscal 2022 Total Utility (A)	Unadjusted (1) Most Recent Fiscal 2022 Minnesota Jurisdiction (B)	Unadjusted (1) Projected Fiscal 2023 Total Utility (C)	Unadjusted (1) Projected Fiscal 2023 Minnesota Jurisdiction (D)	Unadjusted (1) Proposed Test Year 2024 Total Utility (E)	Unadjusted (1) Proposed Test Year 2024 Minnesota Jurisdiction (F)
	Operating Revenues						
1	Retail	$999,804	$861,496	$804,229	$693,825	$694,748	$613,782
2	Weather Impact Net Margin Adjustment	0	0	0	0	0	0
3	Other Operating	13,440	11,191	10,434	10,063	10,965	10,496
4	**Total Operating Revenues**	$1,013,244	$872,687	$814,663	$703,888	$705,713	$624,278
5							
6	**Expenses**						
7	Operating Expenses:						
8	Purchased Gas	$746,193	$636,394	$525,746	$447,735	$400,150	$350,434
9	Gas Production and Storage	10,223	8,594	11,041	8,949	8,978	7,927
10	Gas Transmission	1,164	1,021	1,475	1,299	2,464	2,169
11	Gas Distribution	41,017	35,757	42,710	37,252	44,728	39,446
12	Customer Accounting	13,350	11,909	13,379	11,870	13,959	12,641
13	Customer Service and Information	29,663	29,522	20,896	20,748	29,912	29,720
14	Sales, Econ Dev, & Other	68	57	(61)	(54)	43	38
15	Administrative and General	28,545	25,179	29,151	25,665	32,334	28,741
16	Total Operating Expenses	$870,223	$748,434	$644,339	$553,463	$532,568	$471,116
17							
18	Depreciation	$59,583	$53,010	$71,470	$63,423	$83,358	$73,715
19	Amortizations	($9,578)	($9,638)	$0	$0	$0	$0
20							
21	Taxes:						
22	Property	$21,259	$19,769	$20,275	$18,484	$24,706	$22,686
23	Deferred Income Tax & ITC	5,307	4,199	6,780	5,677	7,861	6,666
24	Federal & State Income Tax	5,949	5,040	4,558	3,974	(1,302)	(1,112)
25	Payroll & Other	2,923	2,584	3,463	3,068	3,827	3,431
26	Total Taxes	$35,438	$31,592	$35,075	$31,203	$35,092	$31,671
27							
28	**Total Expenses**	$955,666	$823,398	$750,884	$648,089	$651,017	$576,502
29							
30	Allowance for Funds Used During Constru	$3,467	$3,200	$2,697	$2,317	$2,995	$2,677
31							
32	**Total Operating Income**	$61,045	$52,489	$66,476	$58,116	$57,691	$50,453

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule C-1

		Adjusted (1) Most Recent Fiscal 2022		Adjusted (1) Projected Fiscal 2023		Adjusted (1) Proposed Test Year 2024	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (E)	Minnesota Jurisdiction (F)
	Income Before Taxes						
1	Total Operating Revenues	$1,013,244	$ 872,687	$ 814,053	$ 703,279	$ 703,472	$ 622,037
2	less: Total Operating Expenses	(867,915)	(746,338)	(642,439)	(551,754)	(529,827)	(468,744)
3	Book Depreciation & Amortization	(49,935)	(43,302)	(71,425)	(63,196)	(84,062)	(74,447)
4	Taxes Other Than Income	(29,407)	(26,471)	(30,453)	(27,165)	(31,453)	(27,741)
5	**Total Before Tax Book Income**	**$ 65,988**	**$ 56,576**	**$ 69,735**	**$61,164**	**$ 58,129**	**$ 51,105**
6							
7	**Tax Additions**						
8	Book Depreciation	$59,513	$52,940	$71,399	$63,352	$82,832	$73,521
9	Deferred Income Taxes and ITC	5,237	4,130	6,713	5,610	6,978	5,681
10	Avoided Tax Interest	1,743	1,625	1,454	1,237	1,557	1,382
11	Other Book Additions	60	-	60	-	60	-
12	**Total Tax Additions**	**$66,553**	**$58,695**	**$79,626**	**$70,199**	**$91,426**	**$80,584**
13							
14	**Tax Deductions**						
15	Tax Depreciation and Removal Expense	$85,749	$76,031	$106,446	$93,437	$118,516	$103,482
16	Debt Interest Expense	22,789	20,257	27,366	24,239	30,540	26,879
17	Deferred Gas Costs	0	0	0	0	0	0
18	Meals and FAS 106	0	0	0	0	0	0
19	Other Tax/Book Timing Differences	(7,478)	(6,618)	(3,004)	(2,655)	(3,470)	(3,069)
20	NOL Utilized / (Generated)	6,730	4,401	0	0	0	0
21	Net Preferred Stock Deduction	0	0	0	0	0	0
22	**Total Tax Deductions**	**$107,790**	**$94,072**	**$130,808**	**$115,022**	**$145,585**	**$127,292**
23							
24	**State Taxable Income**	**$24,750**	**$21,200**	**$ 18,553**	**$16,341**	**$ 3,971**	**$4,397**
25							
26	State Income Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
27							
28	**State Taxes before Credits**	**$2,426**	**$2,078**	**$ 1,818**	**$1,601**	**$ 389**	**$431**
29							
30	State R&E Credit	(52)	(43)	(61)	(53)	(61)	(53)
31							
32	**Total State Income Taxes**	**$ 2,373**	**$ 2,035**	**$ 1,757**	**$ 1,549**	**$ 328**	**$ 378**
33							
34	**Federal Taxable Income**	**22,377**	**19,165**	**16,796**	**14,793**	**3,642**	**4,019**
35							
36	Federal Income Tax Rate	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
37							
38	**Federal Taxes before Credits**	**$ 4,699**	**$ 4,025**	**$ 3,527**	**$ 3,106**	**$ 765**	**$ 844**
39							
40	Federal Tax Credits	(344)	(302)	(249)	(216)	(249)	(216)
41							
42	**Total Federal Income Taxes**	**$ 4,355**	**$ 3,723**	**$ 3,278**	**$ 2,891**	**$ 516**	**$ 628**
43							
44	**Total State and Federal Income Taxes**	**$ 6,729**	**$ 5,758**	**$ 5,036**	**$ 4,439**	**$ 844**	**$ 1,006**

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule C-2

		Unadjusted (1) Most Recent Fiscal 2022		Unadjusted (1) Projected Fiscal 2023		Unadjusted (1) Proposed Test Year 2024	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (E)	Minnesota Jurisdiction (F)
	Income Before Taxes						
1	Total Operating Revenues	$ 1,013,244	$ 872,687	$ 814,663	$ 703,888	$ 705,713	$ 624,278
2	less: Total Operating Expenses	(870,223)	(748,434)	(644,339)	(553,463)	(532,568)	(471,116)
3	Book Depreciation & Amortization	(50,004)	(43,372)	(71,470)	(63,423)	(83,358)	(73,715)
4	Taxes Other Than Income	(29,489)	(26,553)	(30,517)	(27,228)	(36,393)	(32,782)
5	**Total Before Tax Book Income**	**$ 63,527**	**$ 54,328**	**$ 68,337**	**$59,773**	**$ 53,394**	**$ 46,665**
6							
7	**Tax Additions**						
8	Book Depreciation	$59,583	$53,010	$71,470	$63,423	$83,358	$73,715
9	Deferred Income Taxes and ITC	5,307	4,199	6,780	5,677	7,861	6,666
10	Avoided Tax Interest	1,743	1,625	1,478	1,260	1,676	1,501
11	Other Book Additions	60	-	-	-	-	-
12	**Total Tax Additions**	**$66,692**	**$58,835**	**$79,727**	**$70,360**	**$92,895**	**$81,882**
13							
14	**Tax Deductions**						
15	Tax Depreciation and Removal Expense	$86,065	$76,348	$106,765	$93,756	$122,378	$107,344
16	Debt Interest Expense	22,862	20,331	27,413	24,309	30,879	27,243
17	Deferred Gas Costs	0	0	0	0	0	0
18	Meals and FAS 106	0	0	0	0	0	0
19	Other Tax/Book Timing Differences	(7,478)	(6,618)	(3,004)	(2,655)	(3,470)	(3,069)
20	NOL Utilized / (Generated)	6,730	4,401	0	0	0	0
21	Net Preferred Stock Deduction	0	0	0	0	0	0
22	**Total Tax Deductions**	**$108,180**	**$94,462**	**$131,173**	**$115,410**	**$149,786**	**$131,518**
23							
24	**State Taxable Income**	**$22,040**	**$18,701**	**$ 16,891**	**$14,723**	**$ (3,496)**	**($2,971)**
25							
26	State Income Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
27							
28	**State Taxes before Credits**	**$2,160**	**$1,833**	**$ 1,655**	**$1,443**	**$ (343)**	**($291)**
29							
30	State R&E Credit	(52)	(43)	(61)	(53)	(61)	(53)
31							
32	**Total State Income Taxes**	**$2,108**	**$1,790**	**$1,594**	**$1,390**	**($403)**	**($344)**
33							
34	**Federal Taxable Income**	**19,932**	**16,911**	**15,296**	**13,333**	**(3,093)**	**(2,627)**
35							
36	Federal Income Tax Rate	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
37							
38	**Federal Taxes before Credits**	**$ 4,186**	**$ 3,551**	**$ 3,212**	**$ 2,800**	**$ (649)**	**$ (552)**
39							
40	Federal Tax Credits	(344)	(302)	(249)	(216)	(249)	(216)
41							
42	**Total Federal Income Taxes**	**$ 3,842**	**$ 3,250**	**$ 2,963**	**$ 2,584**	**$ (898)**	**$ (768)**
43							
44	**Total State and Federal Income Taxes**	**$ 5,949**	**$ 5,040**	**$ 4,558**	**$ 3,974**	**$ (1,302)**	**$ (1,112)**

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF DEFERRED INCOME TAXES
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule C-3

		Adjusted (1) Most Recent Fiscal Year 2022		Adjusted (1) Projected Fiscal Year 2023		Adjusted (1) Proposed Test Year 2024	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (C)	Minnesota Jurisdiction (D)
	Provision for Deferred Income Taxes from Liberalized Depreciation						
1	Production	($77)	($67)	($164)	($143)	$277	$240
2	Storage	492	430	925	803	690	599
3	Transmission	590	598	365	370	673	681
4	Distribution	3,130	2,624	3,545	2,767	1,900	1,117
5	General	873	774	1,765	1,560	3,170	2,801
6	Common	(401)	(355)	247	219	269	238
7	Net Operating Loss (NOL)	(3,915)	1,316	0	0	0	0
8	Amortizations	0	0	0	0	0	0
9	Non-Plant Related	(1,244)	(1,081)	137	141	105	112
10	TOTAL Deferred Income Taxes	($552)	$4,237	$6,820	$5,717	$7,085	$5,788

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company
Gas Operations - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF DEFERRED INCOME TAXES
($000's)

Docket No. G002/GR-23-413
Financial Information
Schedule C-4

		Unadjusted (1) Most Recent Fiscal Year 2022		Unadjusted (1) Projected Fiscal Year 2023		Unadjusted (1) Proposed Test Year 2024	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (C)	Minnesota Jurisdiction (D)
	Provision for Deferred Income Taxes from Liberalized Depreciation						
1	Production	($77)	($67)	($164)	($143)	$277	$240
2	Storage	492	430	925	803	690	599
3	Transmission	659	667	423	428	916	923
4	Distribution	3,130	2,624	3,553	2,775	3,417	2,634
5	General	873	774	1,765	1,560	2,294	2,027
6	Common	(401)	(355)	247	219	269	238
7	Net Operating Loss (NOL)	(3,613)	1,316	0	0	0	0
8	Amortizations	0	0	0	0	0	0
9	Non-Plant Related	(1,244)	(1,081)	137	141	105	112
10	TOTAL Deferred Income Taxes	($181)	$4,306	$6,887	$5,784	$7,967	$6,773

(1) Revenues and expenses for riders have been included where applicable

Northern States Power Company **Docket No. G002/GR-23-413**
Gas Operations - State of Minnesota **Financial Information**
OPERATING INCOME SCHEDULES **Schedule C-5**
DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES
Most Recent Fiscal Year 2022
Proposed Test Year 2023
Unadjusted Test Year 2024

Let: F=Federal Income Tax = 21.00%
M=Minnesota State Income Tax Rate = 9.80%
D=North Dakota State Income Tax Rate = 4.31%
S=South Dakota State Income Tax Rate = 0%
N=Net Income After Interest Deductions but Before Income Taxes

Jurisdictional:

Only Minnesota and Federal Income Taxes

M=	9.80%	(N)
F=	18.94%	(N)
M+F=	28.74%	(N)

Only North Dakota and Federal Income Taxes

D=	4.31%	(N)
F=	20.09%	(N)
D+F=	24.40%	(N)

Only South Dakota and Federal Income Taxes

S=	0.00%	(N)
F=	21.00%	(N)
S+F=	21.00%	(N)

Composite:

Northern States Power Company (Minnesota): Combined Minnesota, North Dakota, South Dakota and Federal Income Taxes:

M + D + S + F 27.97% (N)

Notes:
1. Investment tax credits and surtax credits are ignored.
2. State income taxes are deductible from federal taxable income. Federal income tax is deductible only from North Dakota's taxable income.
3. Net income is defined at each jurisdictional level.
4. Composite income tax rates are determined by the Income Tax Department based upor apportionment laws (unitary and nonunitary) for each state involved.

Northern States Power Company
State of Minnesota Gas Jurisdiction
INCOME STATEMENT ADJUSTMENT SCHEDULE
Unadjusted 2024 Test Year walk forward to Final Adjusted Test Year
($000s)

Docket No. G002/GR-23-413
Financial Information
Schedule D.1 - 2024 Test Year

		Bridge - Unadjusted				Precedential	Adjustment				
Line No.		ADIT Prorate for IRS	Cash Working Capital	Base	Total Unadjusted	Precedential Adjustments	Bad Debt Expense	Black Dog Pipeline	Depreciation Study	Participant Compensation	LTI-Environmental
1	Operating Revenues										
2	Retail Revenue			613,782	613,782						
3	Interdepartmental			7,410	7,410						
4	Other Operating			3,086	3,086						
5	Total Revenue			624,278	624,278						
6											
7	Expenses										
8	Operating Expenses										
9	Base Cost of Gas			350,434	350,434						
12	Gas Production and Storage			7,927	7,927						
13	Gas Transmission			2,169	2,169						
14	Gas Distribution			39,446	39,446						
15	Customer Accounting			12,641	12,641		246				
16	Customer Service and Information			29,720	29,720						
17	Sales, Econ Dev, & Other			38	38	12					
18	Administrative and General			28,741	28,741	(1,871)				85	125
19	Total Operating Expenses			471,116	471,116	(1,858)	246			85	125
20											
21	Depreciation			73,715	73,715			(78)	156		
22	Amortization										
23											
24	Taxes										
25	Property			22,686	22,686						
26	Deferred Income Tax and ITC			6,666	6,666			(54)	(17)		
27	Federal and State Income Tax	(1)	79	(561)	(484)	535	(71)	99	0	(25)	(36)
28	Payroll and Other			3,431	3,431	(4)					
29	Total Taxes	(1)	79	32,221	32,299	531	(71)	45	(17)	(25)	(36)
30											
31	Total Expenses	(1)	79	577,052	577,130	(1,327)	175	(34)	139	61	89
32											
33	Allowance for Funds Used During Construction			2,677	2,677						
34											
35	Net Income	1	(79)	49,903	49,825	1,327	(175)	34	(139)	(61)	(89)
36											
37	Calculation of Revenue Requirements										
38	Rate Base	252	(14,114)	1,298,895	1,285,033			(3,718)	(69)		
39	Required Operating Income	18	(984)	90,533	89,567			(259)	(5)		
40	Operating Income	1	(79)	49,903	49,825	1,327	(175)	34	(139)	(61)	(89)
41	Income Deficiency	16	(905)	40,630	39,742	(1,327)	175	(293)	134	61	89
42	**Revenue Deficiency**	**23**	**(1,270)**	**57,018**	**55,771**	**(1,862)**	**246**	**(411)**	**188**	**85**	**125**

Northern States Power Company
State of Minnesota Gas Jurisdiction
INCOME STATEMENT ADJUSTMENT SCHEDULE
Unadjusted 2024 Test Year walk forward to Final Adjusted Test Year
($000s)

Docket No. G002/GR-23-413
Financial Information
Schedule D.1 - 2024 Test Year

Line No.						Amortization	Rider Removals	Secondary Calculations			
		LTI-Time Based	New Area Surcharge	New Business CIAC	Property Tax Adjustment	Rate Case Expenses	GUIC Rider Removal	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Total
1	Operating Revenues										
2	Retail Revenue						(3,386)				610,396
3	Interdepartmental										7,410
4	Other Operating		1,144								4,230
5	Total Revenue		1,144				(3,386)				622,037
6											
7	Expenses										
8	Operating Expenses										
9	Base Cost of Gas										350,434
12	Gas Production and Storage										7,927
13	Gas Transmission						(1,546)				623
14	Gas Distribution						107				39,553
15	Customer Accounting										12,887
16	Customer Service and Information										29,720
17	Sales, Econ Dev, & Other										50
18	Administrative and General	469									27,550
19	Total Operating Expenses	469					(1,439)				468,744
20											
21	Depreciation			(1)			(270)				73,521
22	Amortization					926					926
23											
24	Taxes										
25	Property				(4,049)		(4)				18,633
26	Deferred Income Tax and ITC			(0)			(913)				5,681
27	Federal and State Income Tax	(135)	329	1	1,164	(266)	537	0	(23)	(619)	1,006
28	Payroll and Other										3,427
29	Total Taxes	(135)	329	0	(2,885)	(266)	(381)	0	(23)	(619)	28,747
30											
31	Total Expenses	334	329	(1)	(2,885)	660	(2,090)	0	(23)	(619)	571,938
32											
33	Allowance for Funds Used During Construction										2,677
34											
35	Net Income	(334)	815	1	2,885	(660)	(1,296)	(0)	23	619	52,776
36											
37	Calculation of Revenue Requirements										
38	Rate Base			(27)			(17,434)	(37)	4,116		1,267,863
39	Required Operating Income			(2)			(1,215)	(3)	287	6,466	94,836
40	Operating Income	(334)	815	1	2,885	(660)	(1,296)	(0)	23	619	52,776
41	Income Deficiency	334	(815)	(2)	(2,885)	660	80	(2)	264	5,847	42,060
42	**Revenue Deficiency**	**469**	**(1,144)**	**(3)**	**(4,049)**	**926**	**113**	**(3)**	**370**	**8,205**	**59,026**

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ADJUSTMENT TYPE	ADJUSTMENT	ADJUSTMENT DESCRIPTION
Precedential	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
Precedential	Dues: Professional Associations	Traditional adjustment made for Association Dues to adjust to allowed level of recovery
Precedential	Aviation	Traditional adjustment made to remove Aviation expenses from recovery
Precedential	Dues: Chamber of Commerce	Traditional adjustment made for Chamber of Commerce dues to adjust to allowed level of recovery
Precedential	Customer Deposits Expense	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Precedential	Foundation and Other Donations	Traditional adjustment made for donations to adjust to allowed level of recovery
Precedential	Economic Development Admin	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Precedential	Economic Development Donations	Traditional adjustment made for economic development donations to adjust to allowed level of recovery
Precedential	Employee Expenses	Traditional adjustment to exclude items not eligible for recovery
Precedential	Foundation Admin	Traditional adjustment removes 100% of Foundation Administration O&M costs
Precedential	AIP over Cap	Removal of AIP over 25% of base salary
Precedential	Long Term Incentive Compensation	Removal long term incentive except for Environmental and Time-Based portions
Precedential	Pension: Non Qualified	Traditional adjustment excludes from recovery non-qualified restoration
Adjustment	Bad Debt	Adjustment bad debt expense for proposed revenue deficiency
Adjustment	Black Dog Pipeline	Remove costs that exceed main and service extension justification
Adjustment	Depreciation Study	Reflects the modified depreciation rates, remaining life updates, and modified salvage rates in the test year
Adjustment	Participant Compensation	Includes participant compensation costs related to Minn. Stat. § 216B.631 (Participant Compensation Statute effective as of May 24, 2023) in the test year.
Adjustment	LTI-Environmental	Include LTI associated with reduced carbon emissions in line with state policy goals.
Adjustment	LTI-Time Based	Include time-based LTI, which is used to ensure eligible employees engage in long-term planning
Adjustment	New Area Surcharge	Remove expenditures that will be collected through the new area surcharge
Adjustment	New Business CIAC	Remove instances where new business CIAC that would have been justified was not collected
Adjustment	Property Tax Adjustment	Incorporate update to property tax forecast
Amortizations	Rate Case Expenses	Amortize rate case expenses
Rider Removal	Rider: GUIC	Removes revenue and expense that will continue to be collected through the GUIC rider

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		Bridge - Unadjusted				Precedential	Adjustment				
Line No.		Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Total Unadjusted	Precedential Adjustments	Bad Debt Expense	Black Dog Pipeline	Depreciation Study	Participant Compensation	LTI-Environmental
1	Operating Revenues										
2	Retail Revenue	693,825			693,825						
3	Interdepartmental	7,369			7,369						
4	Other Operating	2,694			2,694						
5	Total Revenue	703,888			703,888						
6											
7	Expenses										
8	Operating Expenses										
9	Base Cost of Gas	447,735			447,735						
10	Gas Production and Storage	8,949			8,949						
11	Gas Transmission	1,299			1,299						
12	Gas Distribution	37,252			37,252						
13	Customer Accounting	11,870			11,870						
14	Customer Service and Information	20,748			20,748	(0)					
15	Sales, Econ Dev, & Other	(54)			(54)	9					
16	Administrative and General	25,665			25,665	(1,564)					118
17	Total Operating Expenses	553,463			553,463	(1,555)					118
18											
19	Depreciation	63,423			63,423			(78)			
20	Amortization										
21											
22	Taxes										
23	Property	18,484			18,484						
24	Deferred Income Tax and ITC	5,677			5,677			(58)			
25	Federal and State Income Tax	4,368	(1)	45	4,411	448		103			(34)
26	Payroll and Other	3,068			3,068	(3)					
27	Total Taxes	31,596	(1)	45	31,639	445		45			(34)
28											
29	Total Expenses	648,482	(1)	45	648,526	(1,110)		(33)			84
30											
31	Allowance for Funds Used During Construction	2,317			2,317						
32											
33	Net Income	57,723	1	(45)	57,680	1,110		33			(84)
34											
35	Calculation of Revenue Requirements										
36	Rate Base	1,176,423	207	(7,946)	1,168,684			(3,852)			
37	Required Operating Income	81,997	14	(553)	81,458			(269)			
38	Operating Income	57,723	1	(45)	57,680	1,110		33			(84)
39	Income Deficiency	24,274	13	(509)	23,778	(1,110)		(301)			84
40	**Revenue Deficiency**	**34,065**	**19**	**(714)**	**33,369**	**(1,558)**		**(423)**			**118**

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						Amortization	Rider Removals	Secondary Calculations			
Line No.		LTI-Time Based	New Area Surcharge	New Business CIAC	Property Tax Adjustment	Rate Case Expenses	GUIC Rider Removal	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Total
1	Operating Revenues										
2	Retail Revenue						(609)				693,216
3	Interdepartmental										7,369
4	Other Operating										2,694
5	Total Revenue						(609)				703,279
6											
7	Expenses										
8	Operating Expenses										
9	Base Cost of Gas										447,735
10	Gas Production and Storage										8,949
11	Gas Transmission						(552)				746
12	Gas Distribution						(73)				37,179
13	Customer Accounting										11,870
14	Customer Service and Information										20,747
15	Sales, Econ Dev, & Other										(45)
16	Administrative and General	354									24,573
17	Total Operating Expenses	354					(626)				551,754
18											
19	Depreciation			(1)			8				63,352
20	Amortization					(156)					(156)
21											
22	Taxes										
23	Property						6				18,490
24	Deferred Income Tax and ITC			(0)			(9)				5,610
25	Federal and State Income Tax	(102)		0		45	6	0	(3)	(435)	4,439
26	Payroll and Other										3,065
27	Total Taxes	(102)		0		45	3	0	(3)	(435)	31,604
28											
29	Total Expenses	252		(1)		(111)	(615)	0	(3)	(435)	646,554
30											
31	Allowance for Funds Used During Construction										2,317
32											
33	Net Income	(252)		1		111	6	(0)	3	435	59,042
34											
35	Calculation of Revenue Requirements										
36	Rate Base			(14)			77	(2)	450		1,165,341
37	Required Operating Income			(1)			5	(0)	31	5,477	86,701
38	Operating Income	(252)		1		111	6	(0)	3	435	59,042
39	Income Deficiency	252		(2)		(111)	(0)	(0)	29	5,042	27,660
40	**Revenue Deficiency**	**354**		**(2)**		**(156)**	**(0)**	**(0)**	**40**	**7,075**	**38,816**

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ADJUSTMENT TYPE	ADJUSTMENT	ADJUSTMENT DESCRIPTION
Precedential	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
Precedential	Dues: Professional Associations	Traditional adjustment made for Association Dues to adjust to allowed level of recovery
Precedential	Aviation	Traditional adjustment made to remove Aviation expenses from recovery
Precedential	Dues: Chamber of Commerce	Traditional adjustment made for Chamber of Commerce dues to adjust to allowed level of recovery
Precedential	Customer Deposits Expense	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Precedential	Foundation and Other Donations	Traditional adjustment made for donations to adjust to allowed level of recovery
Precedential	Economic Development Admin	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Precedential	Economic Development Donations	Traditional adjustment made for economic development donations to adjust to allowed level of recovery
Precedential	Employee Expenses	Traditional adjustment to exclude items not eligible for recovery
Precedential	Foundation Admin	Traditional adjustment removes 100% of Foundation Administration O&M costs
Precedential	AIP over Cap	Removal of AIP over 25% of base salary
Precedential	Long Term Incentive Compensation	Removal long term incentive except for Environmental and Time-Based portions
Precedential	Pension: Non Qualified	Traditional adjustment excludes from recovery non-qualified restoration
Adjustment	Bad Debt	Adjustment bad debt expense for proposed revenue deficiency
Adjustment	Black Dog Pipeline	Remove costs that exceed main and service extension justification
Adjustment	Depreciation Study	Reflects the modified depreciation rates, remaining life updates, and modified salvage rates in the test year
Adjustment	Participant Compensation	Includes participant compensation costs related to Minn. Stat. § 216B.631 (Participant Compensation Statute effective as of May 24, 2023) in the test
Adjustment	LTI-Environmental	Include LTI associated with reduced carbon emissions in line with state policy goals.
Adjustment	LTI-Time Based	Include time-based LTI, which is used to ensure eligible employees engage in long-term planning
Adjustment	New Area Surcharge	Remove expenditures that will be collected through the new area surcharge
Adjustment	New Business CIAC	Remove instances where new business CIAC that would have been justified was not collected
Adjustment	Property Tax Adjustment	Adjust property tax to last actual year
Amortizations	Rate Case Expenses	Amortize rate case expenses
Rider Removal	Rider: GUIC	Removes revenue and expense that will continue to be collected through the GUIC rider

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ADJUSTMENT TYPE	ADJUSTMENT	ADJUSTMENT DESCRIPTION
Precedential	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
Precedential	Dues: Professional Associations	Traditional adjustment made for Association Dues to adjust to allowed level of recovery
Precedential	Aviation	Traditional adjustment made to remove Aviation expenses from recovery
Precedential	Dues: Chamber of Commerce	Traditional adjustment made for Chamber of Commerce dues to adjust to allowed level of recovery
Precedential	Customer Deposits Expense	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Precedential	Foundation and Other Donations	Traditional adjustment made for donations to adjust to allowed level of recovery
Precedential	Economic Development Admin	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Precedential	Economic Development Donations	Traditional adjustment made for economic development donations to adjust to allowed level of recovery
Precedential	Employee Expenses	Traditional adjustment to exclude items not eligible for recovery
Precedential	Foundation Admin	Traditional adjustment removes 100% of Foundation Administration O&M costs
Precedential	AIP over Cap	Removal of AIP over 25% of base salary
Precedential	Long Term Incentive Compensation	Removal long term incentive except for Environmental and Time-Based portions
Precedential	Pension: Non Qualified	Traditional adjustment excludes from recovery non-qualified restoration
Adjustment	Bad Debt	Adjustment bad debt expense for proposed revenue deficiency
Adjustment	Black Dog Pipeline	Remove costs that exceed main and service extension justification
Adjustment	Depreciation Study	Reflects the modified depreciation rates, remaining life updates, and modified salvage rates in the test year
Adjustment	Participant Compensation	Includes participant compensation costs related to Minn. Stat. § 216B.631 (Participant Compensation Statute effective as of May 24, 2023) in the test year.
Adjustment	LTI-Environmental	Include LTI associated with reduced carbon emissions in line with state policy goals.
Adjustment	LTI-Time Based	Include time-based LTI, which is used to ensure eligible employees engage in long-term planning
Adjustment	New Area Surcharge	Remove expenditures that will be collected through the new area surcharge
Adjustment	New Business CIAC	Remove instances where new business CIAC that would have been justified was not collected
Adjustment	Property Tax Adjustment	Incorporate update to property tax forecast
Amortizations	Rate Case Expenses	Amortize rate case expenses
Rider Removal	Rider: GUIC	Removes revenue and expense that will continue to be collected through the GUIC rider

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Schedule D.3 - 2022 Actual Year

		Bridge - Unadjusted				Precedential			Calculations		
Line No.		Base	Cash Working Capital	Net Operating Loss	Total Unadjusted	Black Dog Pipeline	Precedential Adjustments	XES Allocation on Labor Hours	Cash Working Capital	Change in Cost of Capital	Total
1	Operating Revenues										
2	Retail Revenue	861,496			861,496						861,496
3	Interdepartmental	8,769			8,769						8,769
4	Other Operating	2,422			2,422						2,422
5	Total Revenue	872,687			872,687						872,687
6											
7	Expenses										
8	Operating Expenses										
9	Base Cost of Gas	636,394			636,394						636,394
10	Gas Production and Storage	8,594			8,594						8,594
11	Gas Transmission	1,021			1,021						1,021
12	Gas Distribution	35,757			35,757						35,757
13	Customer Accounting	11,909			11,909						11,909
14	Customer Service and Information	29,522			29,522		(5)				29,517
15	Sales, Econ Dev, & Other	57			57		7				64
16	Administrative and General	25,179			25,179		(1,713)	(384)			23,081
17	Total Operating Expenses	748,434			748,434		(1,711)	(384)			746,338
18											
19	Depreciation	53,010			53,010	(70)					52,940
20	Amortization	(9,638)			(9,638)						(9,638)
21											
22	Taxes										
23	Property	19,769			19,769						19,769
24	Deferred Income Tax and ITC	2,884		1,316	4,199	(69)					4,130
25	Federal and State Income Tax	6,306	79	(1,346)	5,040	114	493	113	(2)		5,758
26	Payroll and Other	2,584			2,584		(3)	(9)			2,572
27	Total Taxes	31,543	79	(30)	31,592	44	490	104	(2)		32,229
28											
29	Total Expenses	823,349	79	(30)	823,398	(25)	(1,221)	(281)	(2)		821,869
30											
31	Allowance for Funds Used During Construction	3,200			3,200						3,200
32											
33	Net Income	52,538	(79)	30	52,489	25	1,221	281	2		54,018
34											
35	Calculation of Revenue Requirements										
36	Rate Base	1,036,214	(13,886)	(658)	1,021,670	(3,990)			284		1,017,964
37	Required Operating Income	72,846	(976)	(46)	71,823	(281)			20	3,359	74,922
38	Operating Income	52,538	(79)	30	52,489	25	1,221	281	2		54,018
39	Income Deficiency	20,308	(897)	(76)	19,335	(306)	(1,221)	(281)	18	3,359	20,904
40	**Revenue Deficiency**	**28,499**	**(1,258)**	**(107)**	**27,133**	**(429)**	**(1,714)**	**(394)**	**26**	**4,714**	**29,336**

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ADJUSTMENT TYPE	ADJUSTMENT	ADJUSTMENT DESCRIPTION
Precedential	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
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Precedential	Aviation	Traditional adjustment made to remove Aviation expenses from recovery
Precedential	Dues: Chamber of Commerce	Traditional adjustment made for Chamber of Commerce dues to adjust to allowed level of recovery
Precedential	Customer Deposits Expense	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Precedential	Foundation and Other Donations	Traditional adjustment made for donations to adjust to allowed level of recovery
Precedential	Economic Development Admin	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Precedential	Economic Development Donations	Traditional adjustment made for economic development donations to adjust to allowed level of recovery
Precedential	Employee Expenses	Traditional adjustment to exclude items not eligible for recovery
Precedential	Foundation Admin	Traditional adjustment removes 100% of Foundation Administration O&M costs
Precedential	AIP over Cap	Removal of AIP over 25% of base salary
Precedential	Long Term Incentive Compensation	Removal long term incentive except for Environmental and Time-Based portions
Precedential	Pension: Non Qualified	Traditional adjustment excludes from recovery non-qualified restoration
Adjustment	Black Dog Pipeline	Remove costs that exceed main and service extension justification
Adjustment	XES Allocation on Labor Hours	Assign Service Company costs using employee counts instead of labor hours

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Descriptions of Assumptions and Approaches Used in Developing the Projected Year

This Schedule provides a list of assumptions used to develop the projected year and meets the requirements of Minn. Rules pt. 7825.4000 (D) and (E), related to the rate base, and pt. 7825.4100 (E) and (F), related to the operating income.

GAS DKT SALES

The methodologies used in preparation of the sales forecast are described fully in the testimony of Company witness John M. Goodenough. The following provides the assumptions and approaches used in developing the projected year sales forecast, used by Company witness Goodenough to develop the test year sales forecast. The sales forecast for the projected year is based primarily on projected changes, but also relies on any known changes for the largest customers.

The preparation of the gas Dkt sales and customer forecast is coordinated by the Energy Forecasting area with inputs from applicable operating areas. The sales and customer forecasts are jointly developed, as discussed below, and are reviewed by management before they are included in the forecast updates.

Xcel Energy's Energy Forecasting area uses a combination of forecasting techniques to develop the sales forecast for each customer class as further explained in Company witness Goodenough's testimony. The forecast is developed for the following customer classes, which is more granular than the rate classes:

Residential
Small Commercial
Large Commercial
Small Demand
Large Demand
Small Volume - Interruptible
Medium Volume - Interruptible

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Large Volume - Interruptible
Interdepartmental Sales
Generation Sales
Firm Transportation
Interruptible Transportation
Negotiated Transportation
Interdepartmental Transportation

Ordinary Least Squares ("OLS") multiple regression models provide the foundation of the sales forecasts for the Residential, Small Commercial, Large Commercial, Small Volume-Interruptible, and Medium Volume-Interruptible customer classes. These relationships are determined on a statistical basis and developed for the Minnesota State jurisdiction. Historical sales and customer data used in the development of the regression equations are reviewed for consistency. For the remaining classes, a historical analysis adjusted to reflect any known changes is used.

Customer Growth Forecasts

The number of customers by customer class is forecasted using state-level demographic data in OLS regression models and other statistical techniques. Historical number of customers by class is derived from the billing system.

Dkt Sales by Customer Class

An extensive discussion of the assumptions and approaches used to calculate gas Dkt sales for the test year by each customer class of service is embodied in the testimony of Company witness John M. Goodenough in Volume 2A.

External Data Sources

IHS Markit provided economic and demographic data series, both historical and forecast. Historical weather data was obtained from the National Oceanic and Atmospheric Administration ("NOAA") as measured at its Minneapolis-St. Paul weather station. Forecast weather is presumed to be normal, expressed in terms of twenty-year averaged heating degree days.

Unbilled Sales

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Xcel Energy reads its customers' meters each working day according to a meter reading schedule based on twenty-one billing cycles. The "revenue month" sales recorded for the current month reflect consumption that has occurred in both the previous month and the current month. Revenue month sales lag approximately fifteen days behind the calendar month.

Unbilled sales are the consumption that occurred during the current (calendar) month not yet recorded due to the constraints of the meter reading schedule. Test year monthly calendar budget sales are calculated, by class, by estimating the daily revenue month-based sales components (base load and weather influenced load) and then multiplying these amounts by the number of days in the calendar month. Please refer to Company witness Goodenough's testimony for specifics regarding these calculations.

OPERATING EXPENSES

Purchased Gas Expense

The annual forecast of purchased gas expense is a projected expense prepared using a computer model. The data inputs for the model include the Company's monthly sales forecast, a "lost and unaccounted for" factor, pipeline transportation and storage contracts, and supply contracts. The model uses the monthly sales projections and the "lost and unaccounted for" factor to project monthly sales volumes. The model then satisfies monthly projected required sales volumes by drawing on supply and storage contracts via transportation contracts described in detail within the model. The contract provisions and physical restrictions determine the monthly availability within the model of term gas supply contracts, as well as Xcel Energy liquefied natural gas and propane-air peak shaving supplies. The model then assumes spot market gas is readily available to satisfy any remaining monthly projected required sales volumes not met by the modeled term or storage resource portfolio.

Once the volume requirements are met, the model then projects the purchased gas expense for both fixed and variable costs. The fixed costs are modeled to reflect transportation demand, storage reservation, and gas supply demand fees. Interstate pipeline transportation and storage costs are set by FERC approved tariffs or defined in specific agreements. In the model, the costs correspond to and are associated with each resource (i.e. transportation/storage resource or gas supply resource).

The variable costs for pipeline transportation and storage services are set by FERC approved tariffs and are used to calculate the variable transport costs for the model. These pipeline variable costs include volumetric pipeline commodity costs, fuel, and ACA surcharges.

The variable costs for gas supply, also known as "commodity charges," are typically tied to price indices published in various gas industry publications. In the Purchased Gas Expense model, the company uses a combination of market indicators such as NYMEX and various long-term price forecasts published by highly respected, industry-leading sources such as Wood Mackenzie and S&P Global. The forecast is NYMEX based for the first few years, and then it transitions into blending the NYMEX curve with the vendor forecasts to develop a composite forecast. The company used the following weightings for each component at various time intervals: Balance of the year plus two years is 100% NYMEX, years 3 and beyond is a weighted average of NYMEX (25%), Wood Mackenzie (37.5%), and S&P Global (37.5%). The resulting prices are applied to the respective forecasted volumes to calculate the gas supply expense portion of the model.

Xcel Energy operates its Minnesota/North Dakota gas system in an integrated fashion. Purchasing, dispatching, and monitoring decisions are made with the entire system in mind. The total system costs are then allocated between the two states based on total system sales forecasts for commodity costs, and projected design day demand for fixed costs.

Business Area Operating Expense

The budget process is described in detail in volume 5. The budgets used in the development of the 2024 test year cost of service are based on a combination of projected expenses and known changes to expense levels developed as part of the 2024 annual budget process. The projected changes are determined using the below described factors. Wherever there was a known change in the business, a projected amount was included in the budget to reflect that known change. The budgets for both O&M and Capital Expenditures are developed within each business area of Xcel Energy.

Business area operating expense budgets are prepared by each of the responsible managers of Xcel Energy. Operating expense budgets are prepared for each applicable Xcel Energy legal entity. Business areas prepare a separate budget for NSP-Minnesota, each of the other Xcel Energy utility companies and Xcel Energy Services Inc. (the Service Company).

Expenses are categorized as either Operating Labor or Operating Non-Labor. Managers are responsible for creating the annual budget for their organization. Each manager uses the best information available including historical cost trends, vendor cost quotes, project estimates, etc., as well as information provided from Corporate, which includes contracted wage increases for union employees, estimated wage increases for non-union employees, transportation rates, purchasing and warehousing rates, overall inflation/escalation factors, etc. As part of the process, each area assigns the expenses to the proper business unit, cost element, and internal order (where appropriate). The combination of those items determines the assignment to the appropriate legal entity, utility (electric or gas), and FERC account to which the expenses are recorded.

As noted above, business areas are responsible for assigning the appropriate costs to NSP-Minnesota and appropriately to the electric and gas utilities. Once the forecasts are developed in total for NSP-Minnesota and by utility, the revenue requirements area assigns those costs to the proper jurisdictions. The assumptions and approaches used to develop the jurisdictional assignments are described in the Direct Testimony of Company witnesses Nicole L. Doyle and Benjamin C. Halama.

As noted above, there are two primary components of the O&M forecast:

1) Labor Expenses
2) Non-Labor Expenses

Labor

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Operating Labor includes productive labor dollars plus a corporate average labor additive component to cover non-productive time. Employee-related expenses such as pension costs, medical and group life insurance, and worker's compensation are the responsibility of the Shared Services business area and are included in Administrative and General Expenses.

Preparation of the operating labor forecast begins with a determination of employee needs for the coming year. The labor costs are developed by entering individual employee wage information, applying the contractual wage increase for union employees and an estimated wage increase for all other employees, determined by the Shared Services business area and determining productive hours/dollars, then adding a corporate average labor additive component to cover expenses associated with non-productive time (vacation, sick leave, other/injury, inclement weather, holidays).

Each business area is responsible for entering the forecast of labor dollars into the on-line budget system and assigning the labor to the appropriate business unit, labor cost element, and internal order (where appropriate). The combination of these items determines the costs applicable to legal entity, utility, and FERC account (including capital labor assignment).

Pension, medical, and workers compensation costs are projected costs forecast by the Shared Services business area with the assistance of an independent actuarial service. Payroll taxes for the most recent twelve month actuals are used in the budget year and the projected labor costs. These costs are applied to labor through a loading factor, which accomplishes assigning the appropriate amount of labor-related benefits to operating labor and capital labor.

The Shared Services business area is also responsible for forecasting the incentive compensation costs to be included in the budget. Incentive compensation costs associated with NSP-Minnesota employees are included in the operating labor budget as a part of Administrative and General costs. Labor costs assigned to NSP-Minnesota from the Service Company include incentive compensation as a portion of the labor overhead allocation and therefore, are included as costs in the same FERC account as the assigned labor costs.

Non-Labor

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ASSUMPTIONS AND APPROACHES USED
IN PROJECTING EACH MAJOR ELEMENT OF OPERATING INCOME

Non-labor expenses include the costs associated with helping employees complete their tasks, such as materials, transportation, supplies, and other expenses. As noted above, business area managers are responsible for projecting non-labor costs using the best information available. Any known business changes for the budget year are incorporated using the best cost projections available at the time the budget is created.

As with labor costs, each business area is responsible for assigning the non labor costs to the appropriate business unit, cost element, and internal order (where appropriate). The combination of these items determines the costs applicable to legal entity, utility, and FERC account (including capital labor assignment). The FERC number is used as the basis to develop electric or gas costs of service studies.

Other Expenses

Depreciation and Amortization

Book depreciation expense is a projected expense based on projected average monthly plant in service by functional class multiplied times one-twelfth of the annual straight-line depreciation rate developed for each functional guideline class. The depreciation lives and rates used are those approved by the Commission in Docket E,G002/D-19-723 and Docket E,G002/D-21-584 and proposed by the Company in Docket E,G002/D-22-299. The depreciation reserve is initialized from Company records from the most recent end-of-year. This reserve, plus the estimate of monthly net changes such as provision and retirements, provides each new end of year balance. Book Depreciation and other plant-related items are provided by the Capital Asset Accounting business area.

Income Taxes (Current/Deferred)

The Capital Asset Accounting business area is responsible for the calculation of plant-related items such as tax depreciation, investment tax credit flow through, and deferred income taxes, all of which are projected expenses. Deferred income taxes and accumulated deferred tax balances are developed for each functional guideline class for each vintage of property addition based on the difference between tax depreciation and straight line depreciation using the most recent certified and Commission approved book depreciation lives. Income tax depreciation is also calculated on a property vintage basis using the appropriate depreciation methods as defined in the Internal Revenue Code Sections 167 and 168 and supporting Regulations. Historical actual balances for the tax depreciation reserve and accumulated deferred taxes are incorporated into the forecast process along with forecast plant addition and retirement information to produce the forecast expenses, deductions, and balances. The Corporate Income Tax business area provides additional tax expense and deferred tax information for various non-plant related items.

Property Taxes

NSP-Minnesota's gas utility plant in service, including the allocated portion of common plant, is assessed property taxes based on the value of its property and is a projected expense. The level of expense for the budget year is projected by the corporate Property Tax area based on historical property tax assessments updated with projected changes to the market value of the taxed property and projected changes to the state and local tax rates. The corporate Property Tax area monitors activity in the state legislature and local taxing authorities on an ongoing basis and uses the most recent information available when the budget is created.

COST ALLOCATIONS AND ASSIGNMENTS

Company witness Nicole L. Doyle's testimony explains in detail the assumptions and approaches used to assign and allocate costs to the business areas in developing the projected year. The testimony also provides the Service Agreement used to assign and allocate Service Company costs and the NSP-Minnesota Cost Assignment and Allocation Manual (CAAM) which explain the assumptions and approaches used to assign and allocate costs. Costs are assigned or allocated between regulated and unregulated businesses, between the gas and electric utilities, and between jurisdictions. Company witness Benjamin C. Halama provides the Minnesota jurisdictional cost study.

Business areas with Service Company employees and expenses are responsible for assigning the Service Company costs to the appropriate Xcel Energy operating company or affiliate based on the services provided, and in accordance with the FERC and Minnesota Commission approved Service Agreement. Costs from the Service Company are direct assigned to legal entities where possible. Costs that are not directly attributable to a specific legal entity are allocated to the appropriate legal entity through use of approved allocation factors based on the type of service being performed.

CAPITAL EXPENDITURES

The capital budgeting process is explained in Volume 5. Each business area is responsible for forecasting capital expenditures by project. The capital expenditures for known individual projects reflect actual projected costs. The expenditures for general maintenance, new business, and government-ordered relocates are based on historical trends, economic forecasts, estimated new meters (which is based on customer growth expectations discussed above, as well as any nondiscretionary work (known relocates)). The capital expenditure budgets are entered by the business areas into the on-line budget system with the appropriate information to enable calculation of the plant-related information discussed above. The capital expenditure information is interfaced to the plant system for the calculations to be performed.

JURISDICTIONAL ASSIGNMENT

The Revenue Requirements area is responsible for the assignment of the O&M and capital expenditure amounts to the jurisdictions that NSP-Minnesota serves. The assumptions and approaches used to make the jurisdictional assignment is detailed in the NSPM CAAM and described in the testimonies of Company witnesses Nicole L. Doyle and Benjamin C. Halama.

Northern States Power Company
Gas Utility - State of Minnesota
Operating Income Jurisdictional Allocation Factors

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Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine Minnesota jurisdictional O&M expense amounts for all of the years presented in these schedules.	
1	Production	Design Day Demand
2	Transmission	Load Dispatch
3	Distribution	Customers/Direct Assigned
4	Customer Accounting	Customers
5	Customer Service & Information	Customers
6	Sales, Econ Dvlp & Other	Customers
7	Administrative & General	Customers

Northern States Power Company
Gas Utility - State of Minnesota
Operating Income Jurisdictional Allocation Factors
OPERATING INCOME JURISDICTIONAL ALLOCATION FACTORS

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		Most Recent Fiscal Year 2022			Projected Fiscal Year 2023			Proposed Test Year 2024 (Adjusted & Unadjusted)		
Line No.	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor
1	**Design Day Demand**	874,955	764,644	**87.3923%**	897,827	779,336	**86.8025%**	897,827	779,336	**86.8025%**
2	Design Day Demand	874,955	764,644	87.3923%	897,827	779,336	86.8025%	897,827	779,336	86.8025%
	MCF	128,216,697	112,875,569	88.0350%	133,116,539	118,778,662	89.2291%	133,116,539	118,778,662	89.2291%
	Load Dispatch			**87.7137%**			**88.0158%**			**88.0158%**
3	**Customers**	542,836	480,711	**88.5554%**	555,347	490,673	**88.3543%**	555,347	490,673	**88.3543%**

RATE OF RETURN COST OF CAPITAL SCHEDULES
(PART 7825.4200)

The following rate of return cost of capital schedules as required by parts 7825.3800 and 7825.4200 shall be filed:

A. A rate of return cost of capital summary schedule showing the calculation of the weighted cost of capital using the average capital structures for the most recent fiscal year the projected fiscal year and projected test year. This information shall be provided for the unconsolidated parent and subsidiary corporations, and for the consolidated parent corporation.

   See Tab A. Rate of Return Summary Schedules.

B. Supporting schedules showing the 12 month average balance calculation of the embedded cost of long-term debt, if any, and the embedded cost of preferred stock, if any, the end of the most recent fiscal year, the projected fiscal year and projected test year

   See Tab B. Long Term Debt for information regarding long-term debt.

   See Tab E. Preferred Equity for information regarding preferred equity. As noted, there are no Preferred Equity Balances.

C. Schedule showing average short-term securities for the proposed test year, most recent fiscal year, and the projected fiscal year.

   See Tab C. Short Term Debt.

Additionally, See Tab D. Common Equity, for schedules showing the 13 month average of Common Equity Balances for the most recent fiscal year, proposed fiscal year, and proposed test year.

   See Tab D. Common Equity

Northern States Power Company, a Minnesota Corporation
Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Cost of Capital

PROPOSED TEST YEAR 2024 COST OF CAPITAL

Capitalization:	**($000's) Amount**	**Percent of Total Capitalization**	**Cost of Capital**	**Weighted Cost of Capital**
Long-Term Debt	$7,716,611	46.87%	4.46%	2.09%
Short-Term Debt	$104,439	0.63%	5.01%	0.03%
Total Debt	$7,821,050	47.50%		2.12%
Net Common Equity	$8,643,779	52.50%	10.20%	5.36%
Total Capitalization	$16,464,830	100.00%		7.48%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

Northern States Power Company (Minnesota)
Regulated Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
SUMMARY SCHEDULES
($000's)

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Capitalization:	Amount (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
ADJUSTED MOST RECENT FISCAL YEAR 2022				
Long-Term Debt	$6,840,842	47.16%	4.18%	1.97%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$31,917	0.22%	6.92%	0.02%
Total Short-Term Debt	$31,917	0.22%		0.02%
Long-Term and Short-Term Debt	$6,872,759	47.38%		1.99%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$7,632,145	52.62%	10.20%	5.37%
Total Equity	$7,632,145	52.62%		5.37%
Total Capitalization	$14,504,904	100.00%		7.36%
ADJUSTED PROJECTED FISCAL YEAR 2023				
Long-Term Debt	$7,169,779	46.42%	4.36%	2.02%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$159,412	1.03%	5.50%	0.06%
Total Short-Term Debt	$159,412	1.03%		0.06%
Long-Term and Short-Term Debt	$7,329,191	47.45%		2.08%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$8,117,479	52.55%	10.20%	5.36%
Total Equity	$8,117,479	52.55%		5.36%
Total Capitalization	$15,446,670	100.00%		7.44%
ADJUSTED "PROPOSED" TEST YEAR 2024				
Long-Term Debt	$7,716,611	46.87%	4.46%	2.09%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$104,439	0.63%	5.01%	0.03%
Total Short-Term Debt	$104,439	0.63%		0.03%
Long-Term and Short-Term Debt	$7,821,050	47.50%		2.12%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$8,643,779	52.50%	10.20%	5.36%
Total Equity	$8,643,779	52.50%		5.36%
Total Capitalization	$16,464,829	100.00%		7.48%

All are average balances; long term and short term debt based on 12 month averages, common equity based on 13 month averages.

Northern States Power Company (Minnesota)
Consolidated - Unadjusted
RATE OF RETURN COST OF CAPITAL SCHEDULES
SUMMARY SCHEDULES
($000's)

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Capitalization:	Amount (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
UNADJUSTED MOST RECENT FISCAL YEAR 2022				
Long-Term Debt	$6,840,842	47.16%	4.18%	1.97%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$31,917	0.22%	6.92%	0.02%
Total Short-Term Debt	$31,917	0.22%		0.02%
Long-Term and Short-Term Debt	$6,872,759	47.38%		1.99%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$7,633,781	52.62%	10.20%	5.37%
Total Equity	$7,633,781	52.62%		5.37%
Total Capitalization	$14,506,540	100.00%		7.36%
UNADJUSTED PROJECTED FISCAL YEAR 2023				
Long-Term Debt	$7,169,779	46.41%	4.36%	2.02%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$159,412	1.04%	5.50%	0.06%
Total Short-Term Debt	$159,412	1.04%		0.06%
Long-Term and Short-Term Debt	$7,329,191	47.45%		2.08%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$8,119,460	52.55%	10.20%	5.36%
Total Equity	$8,119,460	52.55%		5.36%
Total Capitalization	$15,448,651	100.00%		7.44%
UNADJUSTED PROPOSED TEST YEAR YEAR 2024				
Long-Term Debt	$7,716,611	46.86%	4.46%	2.10%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$104,439	0.64%	5.01%	0.03%
Total Short-Term Debt	$104,439	0.64%		0.03%
Long-Term and Short-Term Debt	$7,821,050	47.50%		2.13%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$8,645,749	52.50%	10.20%	5.36%
Total Equity	$8,645,749	52.50%		5.36%
Total Capitalization	$16,466,799	100.00%		7.49%

All are average balances; long term and short term debt based on 12 month averages, common and preferred equity based on 13 month balances.

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
SUMMARY SCHEDULES
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Capitalization:	Amount (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
MOST RECENT FISCAL YEAR 2022				
Long-Term Debt	$23,135,974	58.09%	3.93%	2.28%
Short-Term Debt	$620,092	1.56%	2.27%	0.04%
Long-Term and Short-Term Debt	$23,756,065	59.65%		2.32%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$16,072,121	40.35%	10.20%	4.12%
Total Equity	$16,072,121	40.35%		4.12%
Total Capitalization	$39,828,186	100.00%		6.44%
PROJECTED FISCAL YEAR 2023				
Long-Term Debt	$24,683,295	58.27%	4.10%	2.39%
Short-Term Debt	$591,486	1.40%	6.04%	0.08%
Long-Term and Short-Term Debt	$25,274,781	59.67%		2.47%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$17,083,429	40.33%	10.20%	4.11%
Total Equity	$17,083,429	40.33%		4.11%
Total Capitalization	$42,358,210	100.00%		6.58%
PROJECTED FISCAL YEAR 2024				
Long-Term Debt	$26,430,313	58.64%	4.37%	2.56%
Short-Term Debt	$328,978	0.73%	6.14%	0.04%
Long-Term and Short-Term Debt	$26,759,292	59.37%		2.60%
Preferred Stock (Redeemed 10/31/11	$0	0.00%	0.00%	0.00%
Net Common Equity	$18,313,711	40.63%	10.20%	4.14%
Total Equity	$18,313,711	40.63%		4.14%
Total Capitalization	$45,073,003	100.00%		6.74%

All are average balances; long term debt is based on average end of year balances;
short term debt balances are twelve month averages, common and preferred equity are thirteen month averages.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
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ACTUAL FISCAL YEAR 2022

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	230	187		249,583	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	330	276		149,393	9,750	-	59	49		9,858	6.60%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	210	1,314		248,476	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,561	649	2,254		404,658	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	991	2,161		346,848	21,700	-	66	144		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,851)	329	2,398		295,421	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	426	1,819		247,755	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2022 (FMB) (2)	2.1500	Aug-12	Aug-22	100,000	-	6	40		99,954	2,150	-	28	191		2,370	2.37%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(30,069)	2,556	4,200		463,175	17,000	(1,496)	127	209		18,833	4.07%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	61	375		399,564	10,400	-	73	452		10,925	2.73%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	635	2,782		296,583	12,375	-	29	127		12,532	4.23%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,767	2,999		293,234	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,665	4,302		344,034	12,600	-	70	181		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.6000	Sep-17	Sep-47	600,000	-	5,017	7,380	7,023	580,580	21,600	-	199	293	279	22,372	3.85%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,491	7,915		581,594	17,400	-	380	287		18,066	3.11%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	12,285	9,131		678,583	18,200	-	425	316		18,942	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,546	4,449		419,006	9,563	-	177	498		10,238	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,511	5,808		417,681	13,600	-	51	183		13,834	3.31%
Series Due June 1, 2052 (FMB)	4.5000	May-22	Jun-52	333,333	-	2,375	4,792		489,055	15,000	-	77	154		22,801	4.66%
Other Debt																
Right of Way Notes	var	var	var	3,084	-	-	-		3,084	-	-	-	-		-	0.00%
TOTAL DEBT				6,986,417	(24,360)	45,078	64,584	7,023	6,845,372	277,450	(1,059)	2,109	3,781	279	284,677	4.16%
Unamortized Loss on Reacquired Debt									(4,529)						1,020	
Fees on 5-year Credit Facility (3)									-						389	
GRAND TOTAL and COST OF DEBT									6,840,842						286,086	$\boxed{4.18\%}$

(1) NSPM 2022 issuance of $550M 30 year bond, balance is 8 of 12 months.
(2) NSPM 2012 issuance of $300M 10 year bond, balance is 4 of 12 months.
(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(5) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
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2023 FORECASTED LONG TERM DEBT AND COST
as of July 2023

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	152	124		249,724	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	271	227		149,501	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	194	1,213		248,593	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,016	602	2,092		404,322	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	924	2,017		347,059	21,700	-	66	144		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,744)	310	2,259		295,686	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	403	1,718		247,879	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(28,573)	2,429	3,990		465,008	17,000	(1,496)	127	209		18,833	4.05%
Series Due May 15, 2023 (FMB) (2)	2.6000	May-13	May-23	133,333	-	4	25		133,305	3,467	-	27	168		3,662	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	606	2,654		296,740	12,375	-	29	127		12,532	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,604	2,869		293,527	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,595	4,121		344,284	12,600	-	70	181		12,850	3.73%
Series Due Sep 15, 2047 (FMB)	3.6000	Sep-17	Sep-47	600,000	-	4,817	7,087	6,744	581,352	21,600	-	199	293	279	22,372	3.85%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,111	7,629		582,260	17,400	-	380	287		18,066	3.10%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,860	8,815		679,325	18,200	-	425	316		18,942	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,368	3,949		419,682	9,563	-	177	495		10,235	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,460	5,625		417,916	13,600	-	51	179		13,830	3.31%
Series Due June 1, 2052 (FMB)	4.5000	May-22	Jun-52	500,000	-	3,669	7,277		489,055	22,500	-	120	181		22,801	4.66%
Series Due May 1, 2053 (FMB) (1)	5.1000	May-23	May-53	533,333	2,970	3,726	6,996		525,582	27,200	-	-	1,547		28,747	5.47%
Other Debt																
Right of Way Notes	var	var	var	2,721	-	-	-		2,721	-	-	-	-		-	0.00%
TOTAL DEBT				7,319,388	(20,330)	48,104	70,688	6,744	7,173,521	303,067	(1,059)	2,077	4,873	279	311,355	4.34%
Unamortized Loss on Reacquired Debt									(3,742)						700	
Fees on 5-year Credit Facility (3)									-						405	
GRAND TOTAL and COST OF DEBT									7,169,779						312,461	4.36%

(1) NSPM 2023 issuance of $800M 30 year bond, balance is 8 of 12 months.
(2) NSPM 2013 issuance of $400M 10 year bond, balance is 4 of 12 months.
(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(5) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

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2024 FORECASTED LONG TERM DEBT AND COST
as of September 2023

										Total Bond Cost						
Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	(5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	74	61		249,865	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	213	178		149,609	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	178	1,112		248,710	13,125	-	16	101		13,242	5.32%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	6,471	555	1,929		403,986	25,000	546	47	162		24,663	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	858	1,872		347,270	21,700	-	66	144		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,637)	291	2,121		295,951	16,050	(107)	19	139		16,315	5.51%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	379	1,618		248,003	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(27,073)	2,302	3,781		466,845	17,000	(1,501)	127	209		18,837	4.03%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	577	2,527		296,896	12,375	-	29	127		12,532	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,441	2,739		293,820	12,000	-	163	130		12,293	4.18%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,525	3,941		344,534	12,600	-	70	181		12,850	3.73%
Series Due Sep 15, 2047 (FMB)	3.6000	Sep-17	Sep-47	600,000	-	4,618	6,793	6,465	582,124	21,600	-	199	293	280	22,372	3.84%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	9,731	7,342		582,927	17,400	-	380	287		18,066	3.10%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,434	8,499		680,067	18,200	-	425	316		18,942	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,191	3,443		420,366	9,563	-	177	513		10,253	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,409	5,436		418,156	13,600	-	51	196		13,847	3.31%
Series Due Jun 1, 2052 (FMB)	4.5000	May-22	Jun-52	500,000	-	3,343	7,053		489,604	22,500	-	120	253		22,873	4.67%
Series Due May 1, 2053 (FMB)	5.1000	May-23	May-53	800,000	4,600	5,732	10,793		788,075	40,800	160	199	374		41,213	5.23%
Series Due Mar 1, 2054 (FMB) (1)	5.5000	Mar-24	Mar-54	416,667	-	-	6,155		410,512	22,917	-	-	208		23,125	5.63%
Other Debt																
Right of Way Notes	var	var	var	2,332	-	-	-		2,332	-	-	-	-		-	0.00%
TOTAL DEBT				7,868,999	(17,639)	47,850	77,394	6,465	7,719,652	336,117	(902)	2,249	3,848	280	343,395	4.45%
Unamortized Loss on Reacquired Debt									(3,041)						702	
Fees on 5-year Credit Facility (2)									-						407	
GRAND TOTAL and COST OF DEBT									7,716,611						344,504	$\boxed{4.46\%}$

(1) NSPM 2024 issuance of $500M 30 year bond, balance is 10 of 12 months.
(2) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
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Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
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ACTUAL FISCAL YEAR 2022

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Total Bond Cost: Premium/ Hedge Amortization	Total Bond Cost: Discount Amortization	Total Bond Cost: Expense Amortization	Total Bond Cost: LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	230	187		249,583	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	330	276		149,393	9,750	-	59	49		9,858	6.60%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	210	1,314		248,476	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,561	649	2,254		404,658	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	991	2,161		346,848	21,700	-	66	144		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,851)	329	2,398		295,421	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	426	1,819		247,755	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2022 (FMB) (2)	2.1500	Aug-12	Aug-22	100,000	-	6	40		99,954	2,150	-	28	191		2,370	2.37%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(30,069)	2,556	4,200		463,175	17,000	(1,496)	127	209		18,833	4.07%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	61	375		399,564	10,400	-	73	452		10,925	2.73%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	635	2,782		296,583	12,375	-	29	127		12,532	4.23%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,767	2,999		293,234	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,665	4,302		344,034	12,600	-	70	181		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.6000	Sep-17	Sep-47	600,000	-	5,017	7,380	7,023	580,580	21,600	-	199	293	279	22,372	3.85%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,491	7,915		581,594	17,400	-	380	287		18,066	3.11%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	12,285	9,131		678,583	18,200	-	425	316		18,942	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,546	4,449		419,006	9,563	-	177	498		10,238	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,511	5,808		417,681	13,600	-	51	183		13,834	3.31%
Series Due June 1, 2052 (FMB)	4.5000	May-22	Jun-52	333,333	-	2,375	4,792		489,055	15,000	-	77	154		22,801	4.66%
Other Debt																
Right of Way Notes	var	var	var	3,084	-	-	-		3,084	-	-	-	-		-	0.00%
TOTAL DEBT				6,986,417	(24,360)	45,078	64,584	7,023	6,845,372	277,450	(1,059)	2,109	3,781	279	284,677	4.16%
Unamortized Loss on Reacquired Debt									(4,529)						1,020	
Fees on 5-year Credit Facility (3)									-						389	
GRAND TOTAL and COST OF DEBT									6,840,842						286,086	4.18%

(1) NSPM 2022 issuance of $550M 30 year bond, balance is 8 of 12 months.

(2) NSPM 2012 issuance of $300M 10 year bond, balance is 4 of 12 months.

(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

(5) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
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2023 FORECASTED LONG TERM DEBT AND COST
as of July 2023

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	152	124		249,724	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	271	227		149,501	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	194	1,213		248,593	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,016	602	2,092		404,322	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	924	2,017		347,059	21,700	-	66	144		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,744)	310	2,259		295,686	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	403	1,718		247,879	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(28,573)	2,429	3,990		465,008	17,000	(1,496)	127	209		18,833	4.05%
Series Due May 15, 2023 (FMB) (2)	2.6000	May-13	May-23	133,333	-	4	25		133,305	3,467	-	27	168		3,662	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	606	2,654		296,740	12,375	-	29	127		12,532	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,604	2,869		293,527	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,595	4,121		344,284	12,600	-	70	181		12,850	3.73%
Series Due Sep 15, 2047 (FMB)	3.6000	Sep-17	Sep-47	600,000	-	4,817	7,087	6,744	581,352	21,600	-	199	293	279	22,372	3.85%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,111	7,629		582,260	17,400	-	380	287		18,066	3.10%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,860	8,815		679,325	18,200	-	425	316		18,942	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,368	3,949		419,682	9,563	-	177	495		10,235	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,460	5,625		417,916	13,600	-	51	179		13,830	3.31%
Series Due June 1, 2052 (FMB)	4.5000	May-22	Jun-52	500,000	-	3,669	7,277		489,055	22,500	-	120	181		22,801	4.66%
Series Due May 1, 2053 (FMB) (1)	5.1000	May-23	May-53	533,333	2,970	3,726	6,996		525,582	27,200	-	-	1,547		28,747	5.47%
Other Debt																
Right of Way Notes	var	var	var	2,721	-	-	-		2,721	-	-	-	-		-	0.00%
TOTAL DEBT				7,319,388	(20,330)	48,104	70,688	6,744	7,173,521	303,067	(1,059)	2,077	4,873	279	311,355	4.34%
Unamortized Loss on Reacquired Debt									(3,742)						700	
Fees on 5-year Credit Facility (3)									-						405	
GRAND TOTAL and COST OF DEBT									7,169,779						312,461	4.36%

(1) NSPM 2023 issuance of $800M 30 year bond, balance is 8 of 12 months.
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Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

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2024 FORECASTED LONG TERM DEBT AND COST
as of September 2023

										Total Bond Cost						
Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	(5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	74	61		249,865	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	213	178		149,609	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	178	1,112		248,710	13,125	-	16	101		13,242	5.32%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	6,471	555	1,929		403,986	25,000	546	47	162		24,663	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	858	1,872		347,270	21,700	-	66	144		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,637)	291	2,121		295,951	16,050	(107)	19	139		16,315	5.51%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	379	1,618		248,003	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(27,073)	2,302	3,781		466,845	17,000	(1,501)	127	209		18,837	4.03%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	577	2,527		296,896	12,375	-	29	127		12,532	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,441	2,739		293,820	12,000	-	163	130		12,293	4.18%
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Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,434	8,499		680,067	18,200	-	425	316		18,942	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,191	3,443		420,366	9,563	-	177	513		10,253	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,409	5,436		418,156	13,600	-	51	196		13,847	3.31%
Series Due Jun 1, 2052 (FMB)	4.5000	May-22	Jun-52	500,000	-	3,343	7,053		489,604	22,500	-	120	253		22,873	4.67%
Series Due May 1, 2053 (FMB)	5.1000	May-23	May-53	800,000	4,600	5,732	10,793		788,075	40,800	160	199	374		41,213	5.23%
Series Due Mar 1, 2054 (FMB) (1)	5.5000	Mar-24	Mar-54	416,667	-	-	6,155		410,512	22,917	-	-	208		23,125	5.63%
Other Debt																
Right of Way Notes	var	var	var	2,332	-	-	-		2,332	-	-	-	-		-	0.00%
TOTAL DEBT				7,868,999	(17,639)	47,850	77,394	6,465	7,719,652	336,117	(902)	2,249	3,848	280	343,395	4.45%
Unamortized Loss on Reacquired Debt									(3,041)						702	
Fees on 5-year Credit Facility (2)									-						407	
GRAND TOTAL and COST OF DEBT									7,716,611						344,504	4.46%

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Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

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MOST RECENT FISCAL YEAR 2022	Actual 2022	Actual 2021	Average	Interest 2022	Weighted Average Interest 2022
Northern States Power Company (Minnesota) Long-Term Debt					
First Mortgage Bonds, Series due:					
Aug. 15, 2022, 2.15%	0	300,000	150,000		
May 15, 2023, 2.60%	400,000	400,000	400,000		
July 1, 2025, 7.125%	250,000	250,000	250,000		
March 1, 2028, 6.5%	150,000	150,000	150,000		
April 1, 2031, 2.25%	425,000	425,000	425,000		
Jul. 15, 2035, 5.25%	250,000	250,000	250,000		
Jun. 1, 2036, 6.25%	400,000	400,000	400,000		
Jul. 1, 2037, 6.20%	350,000	350,000	350,000		
Nov. 1, 2039, 5.35%	300,000	300,000	300,000		
Aug. 15, 2040, 4.85%	250,000	250,000	250,000		
Aug. 15, 2042, 3.40%	500,000	500,000	500,000		
May 15, 2044, 4.125%	300,000	300,000	300,000		
Aug 15, 2045, 4.00%	300,000	300,000	300,000		
May 15, 2046, 3.60%	350,000	350,000	350,000		
Sept 15, 2047, 3.60%	600,000	600,000	600,000		
Mar 1, 2050, 2.90%	600,000	600,000	600,000		
Jun 1, 2051, 2.60%	700,000	700,000	700,000		
Apr. 1, 2052, 3.20%	425,000	425,000	425,000		
Jun 1, 2052, 4.50%	500,000	0	250,000		
Other	2,780	3,227	3,004		
Total	7,052,780	6,853,227	6,953,004		
Public Service Company of Colorado Long-Term Debt					
First Mortgage Bonds, Series due:					
Sep. 15, 2022, 2.25%	0	300,000	150,000		
Mar. 15, 2023, 2.50%	250,000	250,000	250,000		
May 15, 2025, 2.90%	250,000	250,000	250,000		
Jun 15, 2028, 3.70%	350,000	350,000	350,000		
Jan 15, 2031,1.90%	375,000	375,000	375,000		
Jun 15, 2031, 1.875%	750,000	750,000	750,000		
Jun 1, 2032, 4.10%	300,000	0	150,000		
Sep 1, 2037, 6.25%	350,000	350,000	350,000		
Aug. 1, 2038, 6.5%	300,000	300,000	300,000		
Aug. 15, 2041, 4.75%	250,000	250,000	250,000		
Sep. 15, 2042, 3.60%	500,000	500,000	500,000		
Mar. 15, 2043, 3.95%	250,000	250,000	250,000		
Mar. 15, 2044, 4.30%	300,000	300,000	300,000		
Jun 15, 2046, 3.55%	250,000	250,000	250,000		
Jun 15, 2047, 3.80%	400,000	400,000	400,000		
Jun 15, 2048, 4.10%	350,000	350,000	350,000		
Sep 15, 2049, 4.05%	400,000	400,000	400,000		
Mar 1, 2050, 3.20%	550,000	550,000	550,000		
Jan 15, 2051, 2.70%	375,000	375,000	375,000		
Jun 1, 2052, 4.50%	400,000	0	200,000		
Total	6,950,000	6,550,000	6,750,000		
Southwestern Public Service Company Long-Term Debt					
First Mortgage Bonds, Series due:					
June 15, 2024, 3.30%	350,000	350,000	350,000		
Aug 15, 2041, 4.50%	400,000	400,000	400,000		
Aug 15, 2046, 3.40%	300,000	300,000	300,000		
Aug 15, 2047, 3.70%	450,000	450,000	450,000		
Nov 15, 2048, 4.40%	300,000	300,000	300,000		
Jun 15, 2049, 3.75%	300,000	300,000	300,000		
May 1, 2050, 3.15%	350,000	350,000	350,000		
May 1, 2050, 3.15%	250,000	250,000	250,000		
Jun 1, 2052, 5.15%	200,000	0	100,000		
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6.0%	100,000	100,000	100,000		
Unsecured Senior F Notes, due Oct. 1, 2036, 6.0%	250,000	250,000	250,000		
Total	3,250,000	3,050,000	3,150,000		

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

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	Actual	Actual		Interest		Weighted Average Interest
Northern States Power Company (Wisconsin) Long-Term Debt	**2022**	**2021**	**Average**	**2022**		**2022**
First Mortgage Bonds Series due:						
June 15, 2024, 3.30%	200,000	200,000	200,000			
Sep 1, 2038, 6.375%	200,000	200,000	200,000			
Oct 1, 2042, 3.70%	100,000	100,000	100,000			
Dec 1, 2047, 3.75%	100,000	100,000	100,000			
Sep 1, 2048, 4.20%	200,000	200,000	200,000			
May 1, 2051, 3.05%	100,000	100,000	100,000			
May 1, 2051, 2.82%	100,000	100,000	100,000			
Sep 15, 2052, 4.86%	100,000	0	50,000			
Fort McCoy System Acquisition - due Oct. 31, 2030, 7%	253	287	270			
Other - Clearwater Investments	486	486	486			
Total	1,100,739	1,000,773	1,050,756			
Other Subsidiaries' Long-Term Debt						
Various Eloigne Co. Affordable Housing	27,358	27,708	27,533			
Total	27,358	27,708	27,533			
Xcel Energy Inc. Debt						
Unsecured Senior Notes, Series due:						
Oct 15, 2023, 0.50%	500,000	500,000	500,000			
Jun 1, 2025, 3.30%	600,000	600,000	600,000			
Dec 1, 2026, 3.35%	500,000	500,000	500,000			
Mar 15, 2027, 1.75%	500,000	500,000	500,000			
Jun 15, 2028, 4.00%	630,000	630,000	630,000			
Dec 1, 2029, 2.60%	500,000	500,000	500,000			
Jun 1, 2030, 3.40%	600,000	600,000	600,000			
Nov 15, 2031, 2.35%	300,000	300,000	300,000			
Jun 1, 2032, 4.60%	700,000	0	350,000			
Jul 1, 2036, 6.50%	300,000	300,000	300,000			
Sep 15, 2041, 4.80%	250,000	250,000	250,000			
Dec 1, 2049, 3.50%	500,000	500,000	500,000			
Total Xcel Energy Inc. debt	5,880,000	5,180,000	5,530,000			
Total long-term debt	24,260,878	22,661,708	23,461,293	$883,087		
Debt Discount, Debt Expense & Loss on Reacquired Debt			(325,320) **1/**	$26,531	**2/**	
Total Including Debt Discount, Debt Expense and Loss on Reacquired Debt			23,135,974	909,618		3.93%

1/ Unamortized balance of debt discount, debt expense and loss of reacquired debt represents average balance @ 12/31/22 & 12/3
2/ Includes up-front fees on 5-year credit facility (long-term for GAAP purposes)

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

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PROJECTED FISCAL YEAR 2023 1/

Northern States Power Company (Minnesota) Long-Term Debt	**Projected 2023**	**Actual 2022**	**Average**	**Interest 2023**	**Weighted Average Interest 2023**
First Mortgage Bonds, Series due:					
May 15, 2023, 2.60%	0	400,000	200,000		
July 1, 2025, 7.125%	250,000	250,000	250,000		
March 1, 2028, 6.5%	150,000	150,000	150,000		
April 1, 2031, 2.25%	425,000	425,000	425,000		
Jul. 15, 2035, 5.25%	250,000	250,000	250,000		
Jun. 1, 2036, 6.25%	400,000	400,000	400,000		
Jul. 1, 2037, 6.20%	350,000	350,000	350,000		
Nov. 1, 2039, 5.35%	300,000	300,000	300,000		
Aug. 15, 2040, 4.85%	250,000	250,000	250,000		
Aug. 15, 2042, 3.40%	500,000	500,000	500,000		
May 15, 2044, 4.125%	300,000	300,000	300,000		
Aug 15, 2045, 4.00%	300,000	300,000	300,000		
May 15, 2046, 3.60%	350,000	350,000	350,000		
Sept 15, 2047, 3.60%	600,000	600,000	600,000		
Mar 1, 2050, 2.90%	600,000	600,000	600,000		
Jun 1, 2051, 2.60%	700,000	700,000	700,000		
Apr. 1, 2052, 3.20%	425,000	425,000	425,000		
Jun 1, 2052, 4.50%	500,000	500,000	500,000		
May 15, 2053, 5.10%	800,000	0	400,000		
Other	2,332	2,780	2,556		
Total	7,452,332	7,052,780	7,252,556		

Public Service Company of Colorado Long-Term Debt			
First Mortgage Bonds, Series due:			
Mar. 15, 2023, 2.50%	0	250,000	125,000
May 15, 2025, 2.90%	250,000	250,000	250,000
Jun 15, 2028, 3.70%	350,000	350,000	350,000
Jan 15, 2031,1.90%	375,000	375,000	375,000
Jun 15, 2031, 1.875%	750,000	750,000	750,000
Jun 1, 2032, 4.10%	300,000	300,000	300,000
Sep 1, 2037, 6.25%	350,000	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000	300,000
Aug. 15, 2041, 4.75%	250,000	250,000	250,000
Sep. 15, 2042, 3.60%	500,000	500,000	500,000
Mar. 15, 2043, 3.95%	250,000	250,000	250,000
Mar. 15, 2044, 4.30%	300,000	300,000	300,000
Jun 15, 2046, 3.55%	250,000	250,000	250,000
Jun 15, 2047, 3.80%	400,000	400,000	400,000
Jun 15, 2048, 4.10%	350,000	350,000	350,000
Sep 15, 2049, 4.05%	400,000	400,000	400,000
Mar 1, 2050, 3.20%	550,000	550,000	550,000
Jan 15, 2051, 2.70%	375,000	375,000	375,000
Jun 1, 2052, 4.50%	400,000	400,000	400,000
Apr 1, 2053, 5.25%	850,000	0	425,000
Total	7,550,000	6,950,000	7,250,000

Southwestern Public Service Company Long-Term Debt			
First Mortgage Bonds, Series due:			
June 15, 2024, 3.30%	350,000	350,000	350,000
Aug 15, 2041, 4.50%	400,000	400,000	400,000
Aug 15, 2046, 3.40%	300,000	300,000	300,000
Aug 15, 2047, 3.70%	450,000	450,000	450,000
Nov 15, 2048, 4.40%	300,000	300,000	300,000
Jun 15, 2049, 3.75%	300,000	300,000	300,000
May 1, 2050, 3.15%	350,000	350,000	350,000
May 1, 2050, 3.15%	250,000	250,000	250,000
Jun 1, 2052, 5.15%	200,000	200,000	200,000
Sep 15, 2053, 6.00%	100,000	0	50,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6.0%	100,000	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6.0%	250,000	250,000	250,000
Total	3,350,000	3,250,000	3,300,000

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

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	Projected	Actual		Interest	Weighted Average Interest
Northern States Power Company (Wisconsin) Long-Term Debt	**2023**	**2022**	**Average**	**2023**	**2023**
First Mortgage Bonds Series due:					
June 15, 2024, 3.30%	200,000	200,000	200,000		
Sep 1, 2038, 6.375%	200,000	200,000	200,000		
Oct 1, 2042, 3.70%	100,000	100,000	100,000		
Dec 1, 2047, 3.75%	100,000	100,000	100,000		
Sep 1, 2048, 4.20%	200,000	200,000	200,000		
May 1, 2051, 3.05%	100,000	100,000	100,000		
May 1, 2051, 2.82%	100,000	100,000	100,000		
Sep 15, 2052, 4.86%	100,000	100,000	100,000		
Jun 15, 2053, 5.30%	125,000	0	62,500		
Fort McCoy System Acquisition - due Oct. 31, 2030, 7%	220	253	236		
Other - Clearwater Investments	486	486	486		
Total	1,225,706	1,100,739	1,163,222		
Other Subsidiaries' Long-Term Debt					
Various Eloigne Co. Affordable	27,358	27,358	27,358		
Total	27,358	27,358	27,358		
Xcel Energy Inc. Debt					
Unsecured Senior Notes, Series due:					
Oct 15, 2023, 0.50%	0	500,000	250,000		
Jun 1, 2025, 3.30%	600,000	600,000	600,000		
Dec 1, 2026, 3.35%	500,000	500,000	500,000		
Mar 15, 2027, 1.75%	500,000	500,000	500,000		
Jun 15, 2028, 4.00%	630,000	630,000	630,000		
Dec 1, 2029, 2.60%	500,000	500,000	500,000		
Jun 1, 2030, 3.40%	600,000	600,000	600,000		
Nov 15, 2031, 2.35%	300,000	300,000	300,000		
Jun 1, 2032, 4.60%	700,000	700,000	700,000		
Jul 1, 2036, 6.50%	300,000	300,000	300,000		
Sep 15, 2041, 4.80%	250,000	250,000	250,000		
Dec 1, 2049, 3.50%	500,000	500,000	500,000		
Aug 15, 2033, 5.45%	800,000	0	400,000		
Total Xcel Energy Inc. debt	6,180,000	5,880,000	6,030,000		
Total long-term debt	25,785,396	24,260,878	25,023,137	$986,463	
Debt Discount, Debt Expense & Loss on Reacquired Debt			(339,842)	26,109 **1/**	
Total Including Debt Discount, Debt Expense and Loss on Reacquired I			24,683,295	1,012,572	4.10%

1/ Includes 5-year Credit Facility Up Front Fees (long-term for GAAP purposes)

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

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PROJECTED FISCAL YEAR 2024

	Projected	Projected		Interest	Weighted Average Interest
Northern States Power Company (Minnesota) Long-Term Debt	2024	2023	Average	2024	2024
First Mortgage Bonds, Series due:					
July 1, 2025, 7.125%	250,000	250,000	250,000		
March 1, 2028, 6.5%	150,000	150,000	150,000		
April 1, 2031, 2.25%	425,000	425,000	425,000		
Jul. 15, 2035, 5.25%	250,000	250,000	250,000		
Jun. 1, 2036, 6.25%	400,000	400,000	400,000		
Jul. 1, 2037, 6.20%	350,000	350,000	350,000		
Nov. 1, 2039, 5.35%	300,000	300,000	300,000		
Aug. 15, 2040, 4.85%	250,000	250,000	250,000		
Aug. 15, 2042, 3.40%	500,000	500,000	500,000		
May 15, 2044, 4.125%	300,000	300,000	300,000		
Aug 15, 2045, 4.00%	300,000	300,000	300,000		
May 15, 2046, 3.60%	350,000	350,000	350,000		
Sept 15, 2047, 3.60%	600,000	600,000	600,000		
Mar 1, 2050, 2.90%	600,000	600,000	600,000		
Jun 1, 2051, 2.60%	700,000	700,000	700,000		
Apr. 1, 2052, 3.20%	425,000	425,000	425,000		
Jun 1, 2052, 4.50%	500,000	500,000	500,000		
May 15, 2053, 5.10%	800,000	800,000	800,000		
Mar 1, 2054, 5.50%	500,000	0	250,000		
Other	2,332	2,332	2,332		
Total	7,952,332	7,452,332	7,702,332		
Public Service Company of Colorado Long-Term Debt					
First Mortgage Bonds, Series due:					
May 15, 2025, 2.90%	250,000	250,000	250,000		
Jun 15, 2028, 3.70%	350,000	350,000	350,000		
Jan 15, 2031,1.90%	375,000	375,000	375,000		
Jun 15, 2031, 1.875%	750,000	750,000	750,000		
Jun 1, 2032, 4.10%	300,000	300,000	300,000		
Sep 1, 2037, 6.25%	350,000	350,000	350,000		
Aug. 1, 2038, 6.5%	300,000	300,000	300,000		
Aug. 15, 2041, 4.75%	250,000	250,000	250,000		
Sep. 15, 2042, 3.60%	500,000	500,000	500,000		
Mar. 15, 2043, 3.95%	250,000	250,000	250,000		
Mar. 15, 2044, 4.30%	300,000	300,000	300,000		
Jun 15, 2046, 3.55%	250,000	250,000	250,000		
Jun 15, 2047, 3.80%	400,000	400,000	400,000		
Jun 15, 2048, 4.10%	350,000	350,000	350,000		
Sep 15, 2049, 4.05%	400,000	400,000	400,000		
Mar 1, 2050, 3.20%	550,000	550,000	550,000		
Jan 15, 2051, 2.70%	375,000	375,000	375,000		
Jun 1, 2052, 4.50%	400,000	400,000	400,000		
Apr 1, 2053, 5.25%	850,000	850,000	850,000		
May 1, 2054, 5.60%	600,000	0	300,000		
	8,150,000	7,550,000	7,850,000		
Southwestern Public Service Company Long-Term Debt					
First Mortgage Bonds, Series due:					
June 15, 2024, 3.30%	0	350,000	175,000		
Aug 15, 2041, 4.50%	400,000	400,000	400,000		
Aug 15, 2046, 3.40%	300,000	300,000	300,000		
Aug 15, 2047, 3.70%	450,000	450,000	450,000		
Nov 15, 2048, 4.40%	300,000	300,000	300,000		
Jun 15, 2049, 3.75%	300,000	300,000	300,000		
May 1, 2050, 3.15%	350,000	350,000	350,000		
May 1, 2050, 3.15%	250,000	250,000	250,000		
Jun 1, 2052, 5.15%	200,000	200,000	200,000		
Sep 15, 2053, 6.00%	100,000	100,000	100,000		
Jun 1, 2054, 5.75%	550,000	0	275,000		
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6.0%	100,000	100,000	100,000		
Unsecured Senior F Notes, due Oct. 1, 2036, 6.0%	250,000	250,000	250,000		
Total	3,550,000	3,350,000	3,450,000		

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

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	Projected 2024	Projected 2023	Average	Interest 2024	Weighted Average Interest 2024
Northern States Power Company (Wisconsin) Long-Term Debt					
First Mortgage Bonds Series due:					
June 15, 2024, 3.30%	0	200,000	100,000		
Sep 1, 2038, 6.375%	200,000	200,000	200,000		
Oct 1, 2042, 3.70%	100,000	100,000	100,000		
Dec 1, 2047, 3.75%	100,000	100,000	100,000		
Sep 1, 2048, 4.20%	200,000	200,000	200,000		
May 1, 2051, 3.05%	100,000	100,000	100,000		
May 1, 2051, 2.82%	100,000	100,000	100,000		
Sep 15, 2052, 4.86%	100,000	100,000	100,000		
Jun 15, 2053, 5.30%	125,000	125,000	125,000		
Jun 1, 2054, 5.50%	350,000	0	175,000		
Fort McCoy System Acquisition - due Oct. 31, 2030, 7%	186	220	203		
Other - Clearwater Investments	486	486	486		
Total	1,375,672	1,225,706	1,300,689		
Other Subsidiaries' Long-Term Debt					
Various Eloigne Co. Affordable Housing Project	27,358	27,358	27,358		
Total	27,358	27,358	27,358		
Xcel Energy Inc. Debt					
Unsecured Senior Notes, Series due:					
Jun 1, 2025, 3.30%	600,000	600,000	600,000		
Dec 1, 2026, 3.35%	500,000	500,000	500,000		
Mar 15, 2027, 1.75%	500,000	500,000	500,000		
Jun 15, 2028, 4.00%	630,000	630,000	630,000		
Dec 1, 2029, 2.60%	500,000	500,000	500,000		
Jun 1, 2030, 3.40%	600,000	600,000	600,000		
Nov 15, 2031, 2.35%	300,000	300,000	300,000		
Jun 1, 2032, 4.60%	700,000	700,000	700,000		
Jul 1, 2036, 6.50%	300,000	300,000	300,000		
Sep 15, 2041, 4.80%	250,000	250,000	250,000		
Dec 1, 2049, 3.50%	500,000	500,000	500,000		
Aug 15, 2033, 5.45%	800,000	800,000	800,000		
Mar 1, 2034, 5.75%	550,000	0	275,000		
Total Xcel Energy Inc. debt	6,730,000	6,180,000	6,455,000		
Total long-term debt	27,785,362	25,785,396	26,785,379	$1,127,885	
Debt Discount, Debt Expense & Loss on Reacquired Debt			(355,066)	$26,640 **1/**	
Total Including Debt Discount, Debt Expense and Loss on Reacquired Debt			26,430,313	1,154,525	4.37%

1/ Includes fees on 5-year credit facility (long-term for GAAP purposes)

Northern States Power Company, a Minnesota Corporation
Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

2024 FORECASTED LONG TERM DEBT AND COST
as of September 2023

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Total Bond Cost: Premium/ Hedge Amortization	Total Bond Cost: Discount Amortization	Total Bond Cost: Expense Amortization	Total Bond Cost: LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	74	61		249,865	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	213	178		149,609	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	178	1,112		248,710	13,125	-	16	101		13,242	5.32%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	6,471	555	1,929		403,986	25,000	546	47	162		24,663	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	858	1,872		347,270	21,700	-	66	144		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,637)	291	2,121		295,951	16,050	(107)	19	139		16,315	5.51%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	379	1,618		248,003	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(27,073)	2,302	3,781		466,845	17,000	(1,501)	127	209		18,837	4.03%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	577	2,527		296,896	12,375	-	29	127		12,532	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,441	2,739		293,820	12,000	-	163	130		12,293	4.18%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,525	3,941		344,534	12,600	-	70	181		12,850	3.73%
Series Due Sep 15, 2047 (FMB)	3.6000	Sep-17	Sep-47	600,000	-	4,618	6,793	6,465	582,124	21,600	-	199	293	280	22,372	3.84%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	9,731	7,342		582,927	17,400	-	380	287		18,066	3.10%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,434	8,499		680,067	18,200	-	425	316		18,942	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,191	3,443		420,366	9,563	-	177	513		10,253	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,409	5,436		418,156	13,600	-	51	196		13,847	3.31%
Series Due Jun 1, 2052 (FMB)	4.5000	May-22	Jun-52	500,000	-	3,343	7,053		489,604	22,500	-	120	253		22,873	4.67%
Series Due May 1, 2053 (FMB)	5.1000	May-23	May-53	800,000	4,600	5,732	10,793		788,075	40,800	160	199	374		41,213	5.23%
Series Due Mar 1, 2054 (FMB) (1)	5.5000	Mar-24	Mar-54	416,667	-	-	6,155		410,512	22,917	-	-	208		23,125	5.63%
Other Debt																
Right of Way Notes	var	var	var	2,332	-	-	-		2,332	-	-	-	-		-	0.00%
TOTAL DEBT				7,868,999	(17,639)	47,850	77,394	6,465	7,719,652	336,117	(902)	2,249	3,848	280	343,395	4.45%
Unamortized Loss on Reacquired Debt									(3,041)						702	
Fees on 5-year Credit Facility (3)									-						407	
GRAND TOTAL and COST OF DEBT									7,716,611						344,504	4.46%

(1) NSPM 2024 issuance of $500M 30 year bond, balance is 10 of 12 months.
(2) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(3) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(4) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company (Minnesota)
Regulated Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Cost of Short Term Debt

Docket No. G002/GR-23-413
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Twelve-month Average

		Interest Cost		Financing Charge		
	Average Net Proceeds 1/	Total 12 Month Interest Expense 2/	Average Interest Cost	Total 12 Month Financing Charge 2/	Average Interest Cost	Average Capital Cost
	(A)	(B)	(C) (B) / (A)	(D)	(E) (D) / (A)	(F) (C)+ (F)
MOST RECENT FISCAL YEAR 2022						
Short-term borrowings 3/	$ 20,942,704	$ 891,832	4.26%	$ 557,366	2.66%	6.92%
Direct Borrowings under 5-year credit facility 4/	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 20,942,704	$ 891,832	4.26%	$ 557,366	2.66%	6.92%
PROJECTED FISCAL YEAR 2023						
Short-term borrowings 3/	$148,101,877	$7,436,638	5.02%	$709,885	0.48%	5.50%
Direct Borrowings under 5-year credit facility 4/	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 148,101,877	$ 7,436,638	5.02%	$ 709,885	0.48%	5.50%
PROPOSED TEST YEAR YEAR 2024						
Short-term borrowings 3/	$99,440,400	$4,274,944	4.30%	$709,875	0.71%	5.01%
Direct Borrowings under 5-year credit facility 4/	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 99,440,400	$ 4,274,944	4.30%	$ 709,875	0.71%	5.01%

1/ Actuals are 12 month average of average daily balances.
Forecast are 12 month average of current and prior month -end average.

2/ Includes interest expense on short term debt and finance charges associated with the June 2019 and September 2022 five year credit facility.
The finance charges represent the monthly cost of NSP-MN unused portion of the credit facility which is primarily used for commercial paper back and letters of credit.

3/ Based on simple average of net proceeds average balances.

4/ Direct Borrowings from the 5-year credit facility are shown as a separate line item.
Upfront fees related to the 5-year credit facility are included in the long-term debt cost and amortized over the life of the credit facility.

Northern States Power Company (Minnesota) **Docket No. G002/GR-23-413**
Regulated Gas Utility - State of Minnesota **Vol 3 II. 5. C.**
RATE OF RETURN COST OF CAPITAL SCHEDULES **Financial Information**
Short Term Debt Balances **Schedule A-1-STD-1, Page 1 of 1**

Twelve-month Average

Month	Short Term Debt NSP-Minnesota 1/
MOST RECENT FISCAL YEAR 2022	
2022 Jan	$36,000,000
Feb	$0
Mar	$0
Apr	$0
May	$0
Jun	$0
Jul	$0
Aug	$0
Sep	$0
Oct	$45,000,000
Nov	$95,000,000
Dec	$207,000,000
12 Month Average	$31,916,667
PROJECTED FISCAL YEAR 2023	
2023 Jan *	$396,000,000
Feb *	$231,000,000
Mar *	$120,000,000
Apr *	$193,000,000
May *	$0
Jun *	$0
Jul	$17,178,766
Aug	$0
Sep	$0
Oct	$339,888,412
Nov	$367,979,784
Dec	$247,898,126
12 Month Average	$159,412,091

* Actuals

Month	Short Term Debt NSP-Minnesota 1/
PROPOSED TEST YEAR 2024	
2024 Jan	$133,285,267
Feb	$170,080,428
Mar	$0
Apr	$0
May	$0
Jun	$0
Jul	$47,092,140
Aug	$85,337,721
Sep	$14,365,828
Oct	$235,119,381
Nov	$298,600,758
Dec	$269,392,214
12 Month Average	$104,439,478

1/ Month-end balances.
Includes commercial paper, utility money pool or direct borrowings under the credit facility.

Northern States Power Company (Minnesota)
Regulated Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Cost of Short Term Debt

Docket No. G002/GR-23-413
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Financial Information
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Twelve-month Average

	Average Net Proceeds 1/	Interest Cost: Total 12 Month Interest Expense 2/	Average Interest Cost	Financing Charge: Total 12 Month Financing Charge 2/	Average Interest Cost	Average Capital Cost
	(A)	(B)	(C) (B) / (A)	(D)	(E) (D) / (A)	(F) (C)+ (F)
MOST RECENT FISCAL YEAR 2022						
Short-term borrowings 3/	$ 20,942,704	$ 891,832	4.26%	$ 557,366	2.66%	6.92%
Direct Borrowings under 5-year credit facility 4/	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 20,942,704	$ 891,832	4.26%	$ 557,366	2.66%	6.92%
PROJECTED FISCAL YEAR 2023						
Short-term borrowings 3/	$148,101,877	$7,436,638	5.02%	$709,885	0.48%	5.50%
Direct Borrowings under 5-year credit facility 4/	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 148,101,877	$ 7,436,638	5.02%	$ 709,885	0.48%	5.50%
PROPOSED TEST YEAR YEAR 2024						
Short-term borrowings 3/	$99,440,400	$4,274,944	4.30%	$709,875	0.71%	5.01%
Direct Borrowings under 5-year credit facility 4/	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 99,440,400	$ 4,274,944	4.30%	$ 709,875	0.71%	5.01%

1/ Actuals are 12 month average of average daily balances.
Forecast are 12 month average of current and prior month -end average.

2/ Includes interest expense on short term debt and finance charges associated with the June 2019 and September 2022 five year credit facility.
The finance charges represent the monthly cost of NSP-MN unused portion of the credit facility which is primarily used for commercial paper back and letters of credit.

3/ Based on simple average of net proceeds average balances.

4/ Direct Borrowings from the 5-year credit facility are shown as a separate line item.
Upfront fees related to the 5-year credit facility are included in the long-term debt cost and amortized over the life of the credit facility.

Northern States Power Company (Minnesota) **Docket No. G002/GR-23-413**
Regulated Gas Utility - State of Minnesota **Vol 3 II. 5. C.**
RATE OF RETURN COST OF CAPITAL SCHEDULES **Financial Information**
Short Term Debt Balances **Schedule A-3-STD-1, Page 1 of 1**

Twelve-month Average

Month	Short Term Debt NSP-Minnesota 1/
MOST RECENT FISCAL YEAR 2022	
2022 Jan	$36,000,000
Feb	$0
Mar	$0
Apr	$0
May	$0
Jun	$0
Jul	$0
Aug	$0
Sep	$0
Oct	$45,000,000
Nov	$95,000,000
Dec	$207,000,000
12 Month Average	$31,916,667
PROJECTED FISCAL YEAR 2023	
2023 Jan *	$396,000,000
Feb *	$231,000,000
Mar *	$120,000,000
Apr *	$193,000,000
May *	$0
Jun *	$0
Jul	$17,178,766
Aug	$0
Sep	$0
Oct	$339,888,412
Nov	$367,979,784
Dec	$247,898,126
12 Month Average	$159,412,091

* Actuals

Month	Short Term Debt NSP-Minnesota 1/
PROPOSED TEST YEAR 2024	
2024 Jan	$133,285,267
Feb	$170,080,428
Mar	$0
Apr	$0
May	$0
Jun	$0
Jul	$47,092,140
Aug	$85,337,721
Sep	$14,365,828
Oct	$235,119,381
Nov	$298,600,758
Dec	$269,392,214
12 Month Average	$104,439,478

1/ Month-end balances.
Includes commercial paper, utility money pool or direct borrowings under the credit facility.

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Short Term Debt Balances
($000's)

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Twelve-month Average

Month	Short Term Debt Xcel Consolidated 1/	Short Term Interest Exp & Fees Xcel Consolidated 2/	Short Term Debt Cost Xcel Consolidated
MOST RECENT FISCAL YEAR 2022			
2022 Jan	$1,309,000		
Feb	$1,184,000		
Mar	$996,400		
Apr	$1,069,000		
May	$292,000		
Jun	$136,000		
Jul	$301,000		
Aug	$179,000		
Sep	$157,700		
Oct	$472,000		
Nov	$532,000		
Dec	$813,000		
12 Month Average	$620,092	14,055	2.27%
PROJECTED FISCAL YEAR 2023			
2023 Jan	$1,194,000		
Feb	$1,014,000		
Mar	$1,078,500		
Apr	$548,000		
May	$420,000		
Jun	$544,000		
Jul	$596,000		
Aug	$19,000		
Sep	$109,859		
Oct	$426,943		
Nov	$614,523		
Dec	$533,008		
12 Month Average	$591,486	35,713	6.04%
PROJECTED FISCAL YEAR 2024			
2024 Jan	$619,894		
Feb	$601,936		
Mar	$419,389		
Apr	$401,097		
May	$268,378		
Jun	$0		
Jul	$47,092		
Aug	$85,338		
Sep	$30,031		
Oct	$380,418		
Nov	$497,274		
Dec	$596,894		
12 Month Average	$328,978	20,209	6.14%

1/ Includes Direct borrowings from 5-year credit facility which are considered short-term debt for regulatory purposes.
2/ Includes interest expense and facility fees.
Note-Credit Facility Re-syndicated June 2019 & Sept 2022.

Northern States Power Company, a Minnesota Corporation
Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Cost of Short-Term Debt

TEST YEAR - 2024 FORECASTED SHORT TERM DEBT AND COST

		Cost of Short Term Debt			
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense (2)	Monthly Fees Expense (3)	Average Short Term Debt Cost
2024 Jan	$133,285,267	$141,349,802	$618,531	$59,017	
2024 Feb	$170,080,428	$151,682,848	$599,514	$53,305	
2024 Mar	$0	$85,040,214	$372,127	$59,017	
2024 Apr	$0	$0	$0	$57,113	
2024 May	$0	$0	$0	$59,017	
2024 June	$0	$0	$0	$72,113	
2024 Jul	$47,092,140	$23,546,070	$83,492	$59,017	
2024 Aug	$85,337,721	$66,214,931	$234,792	$59,017	
2024 Sep	$14,365,828	$49,851,774	$171,068	$57,113	
2024 Oct	$235,119,381	$124,742,605	$410,594	$59,017	
2024 Nov	$298,600,758	$266,860,070	$850,043	$57,113	
2024 Dec	$269,392,214	$283,996,486	$934,783	$59,017	
Average	$104,439,478	$99,440,400			
Total			$ 4,274,944	$ 709,875	
			4.30%	0.71%	5.01%

(1) January through December Average of Month End Balances.

(2) Monthly Interest Expense is based on the weighted average of short term debt outstanding and Interest Rates are based on the Global Insights and Bloomberg Forecast.

(3) Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated on September 19, 2022. This expense represents the monthly cost of NSP-MN unused portion of the credit facility. Credit facility is used primarily as back up for commercial paper and letters of credit. (Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt.)

Northern States Power Company (Minnesota)
Regulated Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity
(000s)

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Financial Information
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Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries*	Regulated Common Equity
MOST RECENT FISCAL YEAR 2022			
2021 Dec	$7,572,954	$1,641	$7,571,313
2022 Jan	$7,630,150	$1,643	$7,628,507
Feb	$7,624,188	$1,632	$7,622,556
Mar	$7,532,353	$1,621	$7,530,732
Apr	$7,558,691	$1,615	$7,557,076
May	$7,578,278	$1,608	$7,576,670
Jun	$7,547,821	$1,605	$7,546,216
Jul	$7,624,397	$1,595	$7,622,802
Aug	$7,699,713	$1,584	$7,698,129
Sep	$7,635,408	$1,576	$7,633,832
Oct	$7,679,671	$1,571	$7,678,100
Nov	$7,720,067	$1,561	$7,718,506
Dec	$7,835,464	$2,016	$7,833,448
13 Month Average	$7,633,781	$1,636	$7,632,145
PROJECTED FISCAL YEAR 2023			
2022 Dec	$7,835,464	$2,016	$7,833,448
2023 Jan	$7,932,842	$2,011	$7,930,831
Feb	$8,030,645	$1,999	$8,028,646
Mar	$7,950,099	$1,988	$7,948,111
Apr	$7,993,336	$1,983	$7,991,353
May	$8,032,332	$1,973	$8,030,359
Jun	$8,072,072	$1,970	$8,070,102
Jul	$8,175,157	$1,970	$8,173,187
Aug	$8,271,078	$1,970	$8,269,108
Sep	$8,204,533	$1,970	$8,202,563
Oct	$8,300,543	$1,970	$8,298,573
Nov	$8,394,156	$1,970	$8,392,186
Dec	$8,360,726	$1,970	$8,358,756
13 Month Average	$8,119,460	$1,982	$8,117,479
PROPOSED TEST YEAR YEAR 2024			
2023 Dec	$8,134,940	$1,970	$8,132,970
2024 Jan	$8,337,247	$1,970	$8,335,277
Feb	$8,493,577	$1,970	$8,491,607
Mar	$8,510,101	$1,970	$8,508,131
Apr	$8,628,525	$1,970	$8,626,555
May	$8,668,503	$1,970	$8,666,533
Jun	$8,610,023	$1,970	$8,608,053
Jul	$8,722,166	$1,970	$8,720,196
Aug	$8,823,575	$1,970	$8,821,605
Sep	$8,781,808	$1,970	$8,779,838
Oct	$8,864,644	$1,970	$8,862,674
Nov	$8,935,932	$1,970	$8,933,962
Dec	$8,883,701	$1,970	$8,881,731
13 Month Average	$8,645,749	$1,970	$8,643,779

*** United Power and Land**

Northern States Power Company (Minnesota)
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity
(000s)

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Financial Information
Schedule A-3-CE, Page 1 of 1

Month	GAAP Common Equity Outstanding
MOST RECENT FISCAL YEAR 2022	
2021 Dec	$7,572,954
2022 Jan	$7,630,150
Feb	$7,624,188
Mar	$7,532,353
Apr	$7,558,691
May	$7,578,278
Jun	$7,547,821
Jul	$7,624,397
Aug	$7,699,713
Sep	$7,635,408
Oct	$7,679,671
Nov	$7,720,067
Dec	$7,835,464
13 Month Average	$7,633,781
PROJECTED FISCAL YEAR 2023	
2022 Dec	$7,835,464
2023 Jan	$7,932,842
Feb	$8,030,645
Mar	$7,950,099
Apr	$7,993,336
May	$8,032,332
Jun	$8,072,072
Jul	$8,175,157
Aug	$8,271,078
Sep	$8,204,533
Oct	$8,300,543
Nov	$8,394,156
Dec	$8,360,726
13 Month Average	$8,119,460
PROPOSED TEST YEAR YEAR 2024	
2023 Dec	$8,134,940
2024 Jan	$8,337,247
Feb	$8,493,577
Mar	$8,510,101
Apr	$8,628,525
May	$8,668,503
Jun	$8,610,023
Jul	$8,722,166
Aug	$8,823,575
Sep	$8,781,808
Oct	$8,864,644
Nov	$8,935,932
Dec	$8,883,701
13 Month Average	$8,645,749

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity
($000's)

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Financial Information
Schedule A-4-CE, Page 1 of 1

Month	Common Equity Outstanding
MOST RECENT FISCAL YEAR 2022	
2021 Dec	15,612,678
2022 Jan	15,783,581
Feb	15,617,646
Mar	15,731,835
Apr	15,832,884
May	15,714,279
Jun	15,970,597
Jul	16,257,178
Aug	16,225,118
Sep	16,384,211
Oct	16,480,044
Nov	16,652,886
Dec	16,674,630
13 Month Average	$16,072,121
PROJECTED FISCAL YEAR 2023	
2022 Dec	16,674,630
2023 Jan	16,850,916
Feb	16,674,078
Mar	16,817,492
Apr	16,876,081
May	16,739,221
Jun	16,914,145
Jul	17,181,761
Aug	17,144,705
Sep	17,338,878
Oct	17,459,515
Nov	17,684,071
Dec	17,729,078
13 Month Average	$17,083,429
PROJECTED FISCAL YEAR 2024	
2023 Dec	17,729,078
2024 Jan	17,920,865
Feb	17,695,533
Mar	18,020,914
Apr	18,100,240
May	17,974,914
Jun	18,254,460
Jul	18,538,151
Aug	18,488,522
Sep	18,674,615
Oct	18,797,876
Nov	18,938,713
Dec	18,944,362
13 Month Average	$18,313,711

Northern States Power Company, a Minnesota Corporation
Gas Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity
($000's)

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
TEST YEAR - 2024 FORECASTED EQUITY BALANCES			
2023 Dec	$8,134,940	$1,970	$8,132,970
2024 Jan	$8,337,247	$1,970	$8,335,277
2024 Feb	$8,493,577	$1,970	$8,491,607
2024 Mar	$8,510,101	$1,970	$8,508,131
2024 Apr	$8,628,525	$1,970	$8,626,555
2024 May	$8,668,503	$1,970	$8,666,533
2024 Jun	$8,610,023	$1,970	$8,608,053
2024 Jul	$8,722,166	$1,970	$8,720,196
2024 Aug	$8,823,575	$1,970	$8,821,605
2024 Sep	$8,781,808	$1,970	$8,779,838
2024 Oct	$8,864,644	$1,970	$8,862,674
2024 Nov	$8,935,932	$1,970	$8,933,962
2024 Dec	$8,883,701	$1,970	$8,881,731
13 Month Average	$8,645,749	$1,970	$8,643,779

(1) United Power and Land.

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Preferred Equity
($000's)

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Financial Information
Schedule A-4-PE-1, Page 1 of 1

Month	Preferred Equity Outstanding	Preferred Equity Dividend	Preferred Equity Redemption Premium	Preferred Equity Outstanding
MOST RECENT FISCAL YEAR 2022				
2021 Dec	0			
2022 Jan	0			
Feb	0			
Mar	0			
Apr	0			
May	0			
Jun	0			
Jul	0			
Aug	0			
Sep	0			
Oct	0			
Nov	0			
Dec	0			
13 Month Average	$0	$0	$0	N/A
PROJECTED FISCAL YEAR 2023				
2022 Dec	0			
2023 Jan	0			
Feb	0			
Mar	0			
Apr	0			
May	0			
Jun	0			
Jul	0			
Aug	0			
Sep	0			
Oct	0			
Nov	0			
Dec	0			
13 Month Average	$0	$0	$0	N/A
PROJECTED FISCAL YEAR 2024				
2023 Dec	0			
2024 Jan	0			
Feb	0			
Mar	0			
Apr	0			
May	0			
Jun	0			
Jul	0			
Aug	0			
Sep	0			
Oct	0			
Nov	0			
Dec	0			
13 Month Average	$0	$0	$0	N/A

Northern States Power Company
Gas Utility - State of Minnesota

RATE STRUCTURE AND DESIGN INFORMATION
(PART 7825.4300)

The following rate structure and design information as required by parts 7825.3800 and 7825.4300 shall be filed:

A. A summary comparison of test year operating revenue under present and proposed rates by customer class cost of service showing the difference in revenue and the percentage change.

B. A detailed comparison of test year operating revenue under present and proposed rates by type of charge including minimum, demand, energy by block, gross receipts, automatic adjustments, and other charge categories within each rate schedule and within each customer class of service.

C. A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations. Such study is appropriate whenever the utility proposes a change in rates which results in a material change in its rate structure.

Northern States Power Company
SUMMARY OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED REVENUES
Test Year Ending December 31, 2024
State of Minnesota Gas Jurisdiction

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Exhibit___(MMT-1), Schedule 5
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	Average	Dkt	Revenue		Increase	
	Customers	Sales	Present	Proposed	Amount	Percent
Firm Service						
Residential Firm	453,981	39,670,184	$364,900,135	$402,667,204	$37,767,069	10.3%
Small Commercial Firm	24,758	5,540,428	$46,549,945	$51,332,959	$4,783,014	10.3%
Large Commercial Firm	11,520	18,126,605	$132,760,194	$142,834,196	$10,074,002	7.6%
Small & Large Commercial Demand Billec	147	2,968,555	$19,846,908	$21,381,911	$1,535,003	7.7%
Total Firm Service	**490,405**	**66,305,772**	**$564,057,182**	**$618,216,271**	**$54,159,089**	**9.6%**
Interruptible Service						
Small Interruptible	156	1,243,581	$6,851,841	$7,237,176	$385,335	5.6%
Medium & Large Interruptible	79	6,759,531	$30,740,013	$32,874,109	$2,134,096	6.9%
Total Interruptible Service	**235**	**8,003,112**	**$37,591,855**	**$40,111,285**	**$2,519,430**	**6.7%**
Total Gas Sales	**490,640**	**74,308,884**	**$601,649,037**	**$658,327,556**	**$56,678,519**	**9.4%**
Transportation Service						
Total Transportation Service	**26**	**12,284,918**	**$7,374,203**	**$9,458,599**	**$2,084,396**	**28.3%**
Generation System	**5**	**215,753**	**$1,634,586**	**$1,649,399**	$14,812	0.9%
Generation Transportation	**4**	**31,969,107**	**$7,148,636**	**$7,239,123**	$90,487	1.3%
Total Retail*	**490,675**	**118,778,662**	**$617,806,462**	**$676,674,677**	**$58,868,215**	**9.5%**
*February 2021 Gas Event surcharges are not included.						
Other Gas Revenues						
Late Payment Revenue Increase				$157,392	$157,392	
Total Sales and Other Gas Revenues			**$617,806,462**	**$676,832,069**	**$59,025,607**	**9.6%**

Northern States Power Company

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES

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Revenue by Rate Schedule

State of Minnesota Gas Jurisdiction

Residential Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	5,447,768		$9.00	$49,029,916	$11.00	$59,925,453	$10,895,537	
Distribution Charge		396,701,840	$0.274927	$109,064,047	$0.376599	$149,397,516	$40,333,469	
CIP Rider Roll In		396,701,840	$0.012722	$5,046,931	$0.000000	$0	($5,046,931)	
GUIC Rider Roll In		396,701,840	$0.021212	$8,415,006	$0.000000	$0	($8,415,006)	
Non-Fuel Subtotal				$171,555,900		$209,322,969	$37,767,069	22.0%
Gas Supply - Summer		96,944,295	$0.433904	$42,064,541	$0.433904	$42,064,541	$0	
Gas Supply - Winter		299,757,544	$0.504674	$151,279,694	$0.504674	$151,279,694	$0	
Gas Supply Subtotal		396,701,840		$193,344,235		$193,344,235	$0	0.0%
Average Customers	453,981		Total	$364,900,135		$402,667,204	$37,767,069	10.3%

Small Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	297,097		$20.00	$5,941,948	$30.00	$8,912,922	$2,970,974	
Distribution Charge		55,404,283	$0.219738	$12,174,426	$0.278538	$15,432,198	$3,257,772	
CIP Base (CCRC) Exemption		4,045	($0.023947)	($97)	($0.036669)	($148)	($51)	
CIP Rider Roll In		55,404,283	$0.012722	$704,866	$0.000000	$0	($704,866)	
CIP Rider Roll In Exemption		4,045	($0.012722)	($51)	$0.000000	$0	$51	
GUIC Rider Roll In		55,404,283	$0.013372	$740,866	$0.000000	$0	($740,866)	
Non-Fuel Subtotal				$19,561,958		$24,344,972	$4,783,014	24.5%
Gas Supply - Summer		12,754,331	$0.432632	$5,517,935	$0.432632	$5,517,935	$0	
Gas Supply - Winter		42,649,952	$0.503402	$21,470,052	$0.503402	$21,470,052	$0	
Gas Supply Subtotal		55,404,283		$26,987,987		$26,987,987	$0	0.0%
Average Customers	24,758		Total	$46,549,945		$51,332,959	$4,783,014	10.3%

Large Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	138,236		$50.00	$6,911,790	$50.00	$6,911,790	$0	
Distribution Charge		181,266,049	$0.184101	$33,371,261	$0.265771	$48,175,259	$14,803,998	
CIP Base (CCRC) Exemption		67,914	($0.023947)	($1,626)	($0.036669)	($2,490)	($864)	
CIP Rider Roll In		181,266,049	$0.012722	$2,306,108	$0.000000	$0	($2,306,108)	
CIP Rider Roll In Exemption		67,914	($0.012722)	($864)	$0.000000	$0	$864	
GUIC Rider Roll In		181,266,049	$0.013372	$2,423,888	$0.000000	$0	($2,423,888)	
Non-Fuel Subtotal				$45,010,557		$55,084,559	$10,074,002	22.4%
Gas Supply - Summer		49,456,119	$0.432632	$21,396,314	$0.432632	$21,396,314	$0	
Gas Supply - Winter		131,809,930	$0.503402	$66,353,324	$0.503402	$66,353,324	$0	
Gas Supply Subtotal		181,266,049		$87,749,638		$87,749,638	$0	0.0%
Average Customers	11,520		Total	$132,760,194		$142,834,196	$10,074,002	7.6%

Northern States Power Company

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Revenue by Rate Schedule

Small and Large Commercial Demand Billed

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,761			$467,364		$467,364	$0	
Distribution Demand Charge		3,462,474	$0.882000	$3,053,902	$0.932000	$3,227,026	$173,124	
Distribution Commodity Charge		29,685,548	$0.084775	$2,516,592	$0.145368	$4,315,329	$1,798,736	
CIP Base (CCRC) Exemption		274,475	($0.023947)	($6,573)	($0.036669)	($10,065)	($3,492)	
CIP Rider Roll In		29,685,548	$0.012722	$377,666	$0.000000	$0	($377,666)	
CIP Rider Roll In Exemption		274,475	($0.012722)	($3,492)	$0.000000	$0	$3,492	
GUIC Rider Roll In		29,685,548	$0.001994	$59,190	$0.000000	$0	($59,190)	
Non-Fuel Subtotal				$6,464,651		$7,999,654	$1,535,003	23.7%
Gas Supply Demand		3,462,474	$0.852050	$2,950,202	$0.852050	$2,950,202	$0	
Gas Supply Commodity		29,685,548	$0.351419	$10,432,055	$0.351419	$10,432,055	$0	
Gas Supply Subtotal				$13,382,257		$13,382,257	$0	0.0%
Average Customers	147		Total	$19,846,908		$21,381,911	$1,535,003	7.7%

Small Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,873		$150.00	$280,969	$170.00	$318,431	$37,463	
Distribution Charge - Tier I		6,217,904	$0.148846	$925,510	$0.205463	$1,277,549	$352,039	
Distribution Charge - Tier II		6,217,904	$0.148846	$925,510	$0.184917	$1,149,794	$224,284	
CIP Rider Roll In		12,435,808	$0.012722	$158,211	$0.000000	$0	($158,211)	
GUIC Rider Roll In		12,435,808	$0.005648	$70,240	$0.000000	$0	($70,240)	
Non-Fuel Subtotal				$2,360,440		$2,745,775	$385,335	16.3%
Gas Supply Charge		12,435,808	$0.361167	$4,491,401	$0.361167	$4,491,401	$0	0.0%
Average Customers	156		Total	$6,851,841		$7,237,176	$385,335	5.6%

Medium and Large Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	946			$289,126		$289,126	$0	
Distribution Charge - Tier I		33,797,655		$2,800,849		$4,725,025	$1,924,177	
Distribution Charge - Tier II		33,797,655		$2,800,849		$4,252,523	$1,451,674	
CIP Base (CCRC) Exemption		320,248	($0.023947)	($7,669)	($0.036669)	($11,743)	($4,074)	
CIP Rider Roll In		67,595,309	$0.012722	$859,963	$0.000000	$0	($859,963)	
CIP Rider Roll In Exemption		320,248	($0.012722)	($4,074)	$0.000000	$0	$4,074	
GUIC Rider Roll In		67,595,309	$0.005648	$381,792	$0.000000	$0	($381,792)	
Non-Fuel Subtotal				$7,120,836		$9,254,931	$2,134,096	30.0%
Gas Supply Charge		67,595,309		$23,619,178		$23,619,178	$0	0.0%
Average Customers	79		Total	$30,740,013		$32,874,109	$2,134,096	6.9%

Northern States Power Company

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Revenue by Rate Schedule

Transportation (summary of 26 customers)

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	312			$97,800		$97,800	$0	
Distribution Charge		122,849,184		$6,406,432		$9,272,253	$2,865,821	
Distribution Demand Charge		694,821		$612,832		$647,573	$34,741	
CIP Base (CCRC) Exemption		86,839,034		($566,089)		($866,833)	($300,744)	
CIP Rider Roll In		122,849,184		$1,562,915		$961,202	($601,714)	
CIP Rider Roll In Exemption		86,839,034		($1,104,786)		($804,042)	$300,744	
GUIC Rider Roll In		122,849,184		$365,099		$150,646	($214,453)	
Average Customers	26		**Total**	$7,374,203		$9,458,599	$2,084,396	28.3%

Generation (summary of 9 customers)

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	108			$31,200		$31,200	$0	
Distribution Charges		321,848,595		$7,277,776		$7,437,083	$159,307	
CIP Base (CCRC) Exemption		319,838,819		($70,029)		($107,232)	($37,204)	
CIP Rider Roll In		321,848,595		$4,094,631		$4,056,827	($37,804)	
CIP Rider Roll In Exemption		319,838,819		($4,069,062)		($4,031,858)	$37,204	
GUIC Rider Roll In		321,848,595		$659,188		$642,985	($16,203)	
Non-Fuel Subtotal				$7,923,704		$8,029,004	$105,299	1.3%
Gas Supply Charge				$859,518		$859,518	$0	0.0%
Average Customers	9		**Total**	$8,783,222		$8,888,522	$105,299	1.2%

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	Rate Base	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production	75,274	39,991	22,852	2,416	0	485	9,529
2	Storage	94,123	50,006	28,574	3,021	0	606	11,916
3	Transmission	134,424	55,594	31,860	3,412	3,126	4,998	35,433
4	Distribution	1,611,639	1,176,990	288,233	20,420	20,478	27,833	77,685
5	General	272,283	188,005	52,812	4,161	3,355	4,822	19,128
6	Common	0	0	0	0	0	0	0
7	**Total Plant In Service**	**2,187,742**	**1,510,586**	**424,332**	**33,430**	**26,959**	**38,745**	**153,691**
8	Production	19,856	10,549	6,028	637	0	128	2,514
9	Storage	45,901	24,386	13,935	1,473	0	296	5,811
10	Transmission	32,868	13,358	7,656	820	751	1,201	9,082
11	Distribution	565,353	432,235	95,142	5,518	5,968	7,051	19,439
12	General	121,351	83,790	23,537	1,854	1,495	2,149	8,525
13	Common	0	0	0	0	0	0	0
14	**Total Depreciation Reserve**	**785,328**	**564,318**	**146,298**	**10,302**	**8,214**	**10,824**	**45,370**
15	**Net Plant**	**1,402,415**	**946,267**	**278,034**	**23,128**	**18,745**	**27,921**	**108,320**
16	**Deductions** (Accum Def Inc Tax)	**214,540**	**152,415**	**38,779**	**2,733**	**2,673**	**3,561**	**14,379**
17	**Additions**	**79,988**	**38,140**	**16,403**	**1,753**	**2,638**	**5,148**	**15,906**
18	**Rate Base**	**1,267,863**	**831,992**	**255,658**	**22,148**	**18,710**	**29,507**	**109,847**

	Income Statement	Minn	Res	Com	Demand	Interrupt	Tran	Gener
19	**Present Retail Revenue**	**617,806**	**364,900**	**179,310**	**19,847**	**37,592**	**7,374**	**8,783**
20	**Present Other Oper Rev**	**4,230**	**2,940**	**744**	**71**	**45**	**70**	**361**
21	**Present Total Operating Rev**	**622,037**	**367,840**	**180,055**	**19,918**	**37,636**	**7,444**	**9,144**
	Operating & Maint Expenses							
22	Purchased Gas Expense	350,434	193,344	114,738	13,382	28,111	0	860
23	Other Purch Gas Exp	0	0	0	0	0	0	0
24	Other Production	7,927	3,990	2,303	254	186	154	1,041
25	Transmission	623	306	175	19	17	28	78
26	Distribution	39,553	29,567	6,057	471	464	739	2,255
27	Customer Accounting	12,887	11,437	1,147	107	171	19	7
28	Customer Service and Information	910	669	204	13	21	2	1
29	Administrative and General	27,550	19,131	5,351	485	599	456	1,527
30	Amortizations; Sales Expense	29,786	15,362	8,890	1,098	2,949	1,343	145
31	**Total Operating & Maint Exp**	**469,670**	**273,807**	**138,865**	**15,829**	**32,517**	**2,741**	**5,912**
32	Book Depreciation	73,521	51,079	14,489	1,128	798	1,136	4,892
33	Taxes Other Than Income Taxes	22,060	11,628	5,761	602	524	836	2,710
34	Prov For Deferred Inc Taxes	5,788	3,770	1,276	107	72	100	463
35	Net Investment Tax Credit	-106	-70	-21	-2	-2	-3	-8
36	**Total Operating Expense**	**570,932**	**340,214**	**160,368**	**17,664**	**33,909**	**4,809**	**13,968**
37	State and Federal Income Taxes	1,006	-363	2,190	302	681	329	-2,132
38	**Total Expense**	**571,938**	**339,851**	**162,558**	**17,965**	**34,590**	**5,138**	**11,836**
39	AFUDC (Rev Credit)	2,677	1,563	706	70	17	36	284
40	**Total Operating Income**	**52,776**	**29,553**	**18,202**	**2,023**	**3,064**	**2,342**	**-2,409**
41	**Rate Base**	**1,267,863**	**831,992**	**255,658**	**22,148**	**18,710**	**29,507**	**109,847**
42	**Present Return on Rate Base**	**4.16%**	**3.55%**	**7.12%**	**9.13%**	**16.38%**	**7.94%**	**-2.19%**
43	**Present Return on Common Equity**	**3.89%**	**2.73%**	**9.52%**	**13.36%**	**27.16%**	**11.08%**	**-8.21%**
44	**Required Return on Rate Base**	**7.48%**	**7.48%**	**7.48%**	**7.48%**	**7.48%**	**7.48%**	**7.48%**
45	**Required Operating Income**	**94,836**	**62,233**	**19,123**	**1,657**	**1,399**	**2,207**	**8,217**
46	**Income Deficiency**	**42,060**	**32,680**	**921**	**-366**	**-1,665**	**-135**	**10,625**
47	**Revenue Deficiency**	**59,026**	**45,538**	**1,936**	**-423**	**-2,137**	**-69**	**14,181**
48	**Deficiency / Pres Retail Revenue**	**9.55%**	**12.48%**	**1.08%**	**-2.13%**	**-5.68%**	**-0.94%**	**161.45%**

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		Minn	Res	Com	Demand	Interrupt	Tran	Gener
	Equal Return vs Present							
	Operating Revenue Requirement							
1	Return On Rate Base	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%
2	Equalized Total Retail Rev	676,832	410,438	181,246	19,423	35,455	7,305	22,964
3	Present Total Retail Revenue	617,806	364,900	179,310	19,847	37,592	7,374	8,783
4	Revenue Deficiency	59,026	45,538	1,936	-423	-2,137	-69	14,181
5	Deficiency / Pres Total Retail Rev	9.55%	12.48%	1.08%	-2.13%	-5.68%	-0.94%	161.45%
	Internal Retail Revenue Reqt							
6	Customer Retail Revenue Requirement	143,160	127,894	14,424	271	501	54	16
7	Average Monthly Customers	490,675	453,981	36,278	147	235	26	9
8	Revenue Requirement $ / Mo / Cust	24.31	23.48	33.13	153.76	177.61	173.30	147.06
9	Capacity Retail Revenue Requirement	144,289	70,871	40,989	4,392	3,133	5,079	19,824
10	Annual Dkt Sales	118,778,662	39,670,184	23,667,033	2,968,555	8,003,112	12,284,918	32,184,860
11	Revenue Requirement $ / Dkt	1.21	1.79	1.73	1.48	0.39	0.41	0.62
	Capacity - Sub Classification							
12	Capacity - Base Revenue Requirement	40,680	15,026	9,041	1,138	3,133	4,677	7,664
13	Capacity - Seasonal Revenue Requirement	71,515	38,885	22,115	2,211	0	196	8,108
14	Peak Shaving Revenue Requirement	32,094	16,961	9,833	1,042	0	207	4,052
15	Base Rev Requirement $ / Dkt	0.34	0.38	0.38	0.38	0.39	0.38	0.24
16	Seasonal Rev Requirement $ / Dkt	0.60	0.98	0.93	0.74	0.00	0.02	0.25
17	Peak Shave Rev Requirement $ / Dkt	0.27	0.43	0.42	0.35	0.00	0.02	0.13
18	Energy Retail Revenue Requirement	38,792	18,182	11,085	1,378	3,710	2,172	2,265
19	Revenue Requirement $ / Dkt	0.33	0.46	0.47	0.46	0.46	0.18	0.07
20	Total Internal Retail Revenue Requirement	326,240	216,948	66,498	6,041	7,344	7,305	22,104
21	Revenue Requirement $ / Dkt	2.75	5.47	2.81	2.03	0.92	0.59	0.69
22	Revenue Requirement $ / Mo / Cust	55.41	39.82	152.75	3,430.34	2,605.21	23,413.91	204,668.79
	External Retail Revenue Reqt							
23	Capacity Revenue Requirement	79,684	48,191	28,441	2,950	0	0	102
24	Energy Revenue Requirement	270,750	145,153	86,297	10,432	28,111	0	757
25	Total External Revenue Requirement	350,434	193,344	114,738	13,382	28,111	0	860
26	Cap Revenue Requirement $ / Dkt	0.67	1.21	1.20	0.99	0.00	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.28	3.66	3.65	3.51	3.51	0.00	0.02
28	Tot Revenue Requirement $ / Dkt	2.95	4.87	4.85	4.51	3.51	0.00	0.03
	Total Retail Revenue Reqt							
29	Customer Revenue Requirement	143,160	127,894	14,424	271	501	54	16
30	Capacity Revenue Requirement	223,973	119,062	69,430	7,342	3,133	5,079	19,926
31	Energy Revenue Requirement	309,542	163,336	97,382	11,810	31,820	2,172	3,022
32	Total Revenue Requirement	676,675	410,292	181,236	19,423	35,455	7,305	22,964
33	Customer Revenue Reqt $ / Dkt	1.21	3.22	0.61	0.09	0.06	0.00	0.00
34	Demand Revenue Reqt $ / Dkt	1.89	3.00	2.93	2.47	0.39	0.41	0.62
35	Energy Revenue Reqt $ / Dkt	2.61	4.12	4.11	3.98	3.98	0.18	0.09
36	Total Revenue Reqt $ / Dkt	5.70	10.34	7.66	6.54	4.43	0.59	0.71
	Proposed Return vs Present							
37	Proposed Total Retail Revenue	676,832	402,813	194,178	21,382	40,112	9,459	8,889
38	Revenue Deficiency	59,026	37,913	14,867	1,535	2,520	2,084	105
39	Deficiency / Pres Total Oper Revenue	9.55%	10.39%	8.29%	7.74%	6.70%	28.27%	1.20%
	Proposed Return vs Equal							
40	Revenue Difference	-0.0014	-7,625	12,932	1,959	4,657	2,153	-14,075
41	Difference / Tot Equal Revenue"	0.00%	-1.86%	7.13%	10.08%	13.13%	29.48%	-61.29%

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	Plant in Service	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	75,274	39,991	22,852	2,416	0	485	9,529
2	**Storage Plant (LNG)**	Design Day	94,123	50,006	28,574	3,021	0	606	11,916
3	Transmission - Average C	Average and Peak	113,117	55,594	31,860	3,412	3,126	4,998	14,127
4	Transmission - Direct Ass	Direct Assign	21,306	0	0	0	0	0	21,306
5	**Transmission Plant**		134,424	55,594	31,860	3,412	3,126	4,998	35,433
	Distribution Plant								
6	Regulator Stations	Average and Peak	605	297	170	18	17	27	76
7	Mains - Minimum System	Modified Customers	424,906	393,132	31,415	127	203	23	6
8	Mains - Average Capacity	Modified Sales W/Tr	224,696	85,023	50,724	6,362	17,153	26,330	39,104
9	Mains - Excess Capacity	Excess Design Day	395,992	220,028	124,097	12,359	0	1,098	38,411
10	Mains - Total		1,045,593	698,182	206,236	18,848	17,356	27,450	77,521
11	Services	Service Study	386,499	335,074	49,304	539	1,444	110	29
12	Meters	Meter & Regul Study	147,691	118,386	26,843	838	1,371	204	49
13	House Regulators	Meter & Regul Study	31,250	25,050	5,680	177	290	43	10
14	Total Distribution Plant		1,611,639	1,176,990	288,233	20,420	20,478	27,833	77,685
15	**General Plant**	Prod-Stor-Tran-Dis	272,283	188,005	52,812	4,161	3,355	4,822	19,128
16	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
17	**Gas Plant in Service**		**2,187,742**	**1,510,586**	**424,332**	**33,430**	**26,959**	**38,745**	**153,691**
	Accum Depr Reserve	**Allocator**							
18	**Production Plant (LPG)**	Design Day	19,856	10,549	6,028	637	0	128	2,514
19	**Storage Plant (LNG)**	Design Day	45,901	24,386	13,935	1,473	0	296	5,811
20	Transmission - Average C	Average and Peak	27,181	13,358	7,656	820	751	1,201	3,394
21	Transmission - Direct Ass	Direct Assign	5,687	0	0	0	0	0	5,687
22	**Transmission Plant**		32,868	13,358	7,656	820	751	1,201	9,082
	Distribution Plant								
23	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
24	Mains	Mains, Overall	261,584	174,669	51,596	4,715	4,342	6,867	19,394
25	Services	Service Study	215,251	186,611	27,458	300	804	61	16
26	Meters	Meter & Regul Study	81,537	65,359	14,820	462	757	113	27
27	House Regulators	Meter & Regul Study	6,981	5,596	1,269	40	65	10	2
28	Total Distribution Plant		565,353	432,235	95,142	5,518	5,968	7,051	19,439
29	**General Plant**	Prod-Stor-Tran-Dis	121,351	83,790	23,537	1,854	1,495	2,149	8,525
30	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
31	**Total Accum Depr**		**785,328**	**564,318**	**146,298**	**10,302**	**8,214**	**10,824**	**45,370**
32	**Net Plant**		**1,402,415**	**946,267**	**278,034**	**23,128**	**18,745**	**27,921**	**108,320**
	Subtractions to Net Plant								
	Accum Deferred Inc Tax	**Allocator**							
33	**Production Plant (LPG)**	Design Day	-247	-131	-75	-8	0	-2	-31
34	**Storage Plant (LNG)**	Design Day	1,745	927	530	56	0	11	221
35	Transmission - Average C	Average and Peak	16,401	8,060	4,619	495	453	725	2,048
36	Transmission - Direct Ass	Direct Assign	3,877	0	0	0	0	0	3,877
37	**Transmission Plant**		20,278	8,060	4,619	495	453	725	5,926
	Distribution Plant								
38	Regulator Stations	Average and Peak	12	6	3	0	0	1	1
39	Mains	Mains, Overall	91,862	61,340	18,119	1,656	1,525	2,412	6,811
40	Services	Service Study	54,838	47,542	6,995	76	205	16	4
41	Meters	Meter & Regul Study	22,547	18,074	4,098	128	209	31	7
42	House Regulators	Meter & Regul Study	2,852	2,286	518	16	26	4	1
43	Total Distribution Plant		172,111	129,247	29,734	1,877	1,966	2,463	6,825
44	**General Plant**	Prod-Stor-Tran-Dis	19,604	13,536	3,802	300	242	347	1,377
45	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
46	Net Operating Loss (NOL	Net Plant	0	0	0	0	0	0	0
47	Non-Plant Related	Labor	1,048	776	168	14	12	17	62
48	**Total Subtractions**		**214,540**	**152,415**	**38,779**	**2,733**	**2,673**	**3,561**	**14,379**

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RATE BASE

Additions to Net Plant

	CWIP	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production Plant (LPG)	Design Day	5,656	3,005	1,717	182	0	36	716
2	Storage Plant (LNG)	Design Day	11,699	6,215	3,552	376	0	75	1,481
3	Transmission - Average C	Average and Peak	872	428	245	26	24	39	109
4	Transmission - Direct Ass	Direct Assignment	0	0	0	0	0	0	0
5	Transmission Plant		872	428	245	26	24	39	109
6	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
7	Mains	Mains Overall	5,171	3,453	1,020	93	86	136	383
8	Services	Service Study	6	5	1	0	0	0	0
9	Meters	Meter & Regul Study	0	0	0	0	0	0	0
10	House Regulators	Meter & Regul Study	179	144	33	1	2	0	0
11	General & Common Plant	Prod-Stor-Tran-Dis	10,543	7,279	2,045	161	130	187	741
12	Total CWIP		34,124	20,529	8,612	839	242	473	3,430
13	**Materials & Supplies**	Tran & Distrib	2,318	1,637	425	32	31	44	150
	Gas In Storage								
14	Total Gas in Storage	Sales, W/ Transp	43,755	14,614	8,718	1,094	2,948	4,525	11,856
15	**Non-Plant Assets & Liab**	Labor	7,968	5,896	1,281	104	91	127	470
	Miscellaneous	**Allocator**							
16	Prepay: Insurance	Tran & Distrib	0	0	0	0	0	0	0
17	Prepay: Miscellaneous	Tran & Distrib	1,820	1,285	334	25	25	34	118
18	Fuel	Sales, W/o Transp	0	0	0	0	0	0	0
19	Total Miscellaneous		1,820	1,285	334	25	25	34	118
	Working Cash								
20	Total Working Cash	Modified O&M Exper	-9,998	-5,820	-2,966	-339	-699	-56	-118
21	**Total Additions**		**79,988**	**38,140**	**16,403**	**1,753**	**2,638**	**5,148**	**15,906**
22	**Total Rate Base**		**1,267,863**	**831,992**	**255,658**	**22,148**	**18,710**	**29,507**	**109,847**
23	**Common Rate Base (@ 52.50%)**		**665,628**	**436,796**	**134,220**	**11,628**	**9,823**	**15,491**	**57,670**
24	Customer Component		543,627	484,737	56,514	743	1,425	167	41
25	Demand Component		686,643	335,984	192,413	20,553	14,985	24,816	97,894
26	Energy Component		37,592	11,272	6,731	853	2,300	4,525	11,912

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	Operating Revenue (Cal Month)								
	Retail Revenue	**Allocator**	**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
1a	**Present Retail Rev**	Direct Assign	**617,806**	**364,900**	**179,310**	**19,847**	**37,592**	**7,374**	**8,783**
1b	**Proposed Retail Rev**	Direct Assign	**676,675**	**402,667**	**194,167**	**21,382**	**40,111**	**9,459**	**8,889**
2	**Retail Rev Increase**		**58,868**	**37,767**	**14,857**	**1,535**	**2,519**	**2,084**	**105**
	Other Retail Revenue								
3	Interdepartmental Genera	Dir Assign; Mod Pres Rev							
4	Transportation	Dir Assign; Mod Pres Rev							
5	**Tot Other Retail Rev**								
	Other Operating Revenue								
3	Late Pay Penalties	Late Pay; Mod Pres	1,652	1,532	109	4	6	0	0
4	Connection Charges	Customers	317	293	23	0	0	0	0
5	Return Check Charges	Customers	38	35	3	0	0	0	0
6	CIP Bonus	Sales, W/o CIP Exer	0	0	0	0	0	0	0
6	Connect Smart	Customers	28	26	2	0	0	0	0
7	Interchange Gas	Design Day	434	230	132	14	0	3	55
8	Damage Claim	Design Day	425	226	129	14	0	3	54
9	Ltd Firm Sales - Rsrvs & \	Design Day	193	103	59	6	0	1	24
10	Distribution Other	Customers	0	0	0	0	0	0	0
11	Miscellaneous Other	1/2 Dsgn Day, 1/2 Ei	1,144	495	288	33	39	63	227
12	**Tot Other Oper Rev - Pres**		**4,230**	**2,940**	**744**	**71**	**45**	**70**	**361**
13	Incr Late Pay - Proposed	Late Pay; Mod Pres	157	146	10	0	1	0	0
14	Incr Connection Charge R	Customers	0	0	0	0	0	0	0
15	**Tot Other Oper Rev - Prop**		**4,387**	**3,086**	**755**	**71**	**45**	**70**	**361**
16a	**Total Oper Rev - Present**		**622,037**	**367,840**	**180,055**	**19,918**	**37,636**	**7,444**	**9,144**
16b	**Total Oper Rev - Proposed**		**681,062**	**405,753**	**194,922**	**21,453**	**40,156**	**9,528**	**9,249**
17	**Operating Rev Increase**		**59,026**	**37,913**	**14,867**	**1,535**	**2,520**	**2,084**	**105**
	Operation & Maintenance (Pg 1 of 2)								
	Purchased Gas Expense	**Allocator**							
18	Commodity	Direct Assign	270,750	145,153	86,297	10,432	28,111	0	757
19	Demand	Direct Assign	79,684	48,191	28,441	2,950	0	0	102
20	Propane	Design Day	0	0	0	0	0	0	0
21	Limited Firm	Design Day	0	0	0	0	0	0	0
22	Total Purchases		350,434	193,344	114,738	13,382	28,111	0	860
	Other Production Expense								
23	Other Purchased Gas	Design Day	1,226	651	372	39	0	8	155
24	MN Gas MGP Clean Up	Sales, W/o Transp	1,020	543	324	41	110	0	3
25	Misc. LPG Op Exp	Design Day	3,419	1,817	1,038	110	0	22	433
26	Misc. LNG Op Exp	1/2 Dsgn Day, 1/2 Ei	2,262	979	569	65	76	124	450
27	Total Other Production Expense		7,927	3,990	2,303	254	186	154	1,041
28	Transmission - Average C	Average and Peak	623	306	175	19	17	28	78
29	Transmission - Other	Other	0	0	0	0	0	0	0
30	**Transmission Expense**		623	306	175	19	17	28	78
	Distribution Expense								
31	Regulator Stations	Average and Peak	525	258	148	16	15	23	66
32	Mains	Mains, Overall	15,402	10,285	3,038	278	256	404	1,142
33	Services	Service Study	3,011	2,610	384	4	11	1	0
34	Meters	Meter & Regul Study	-5,571	-4,466	-1,013	-32	-52	-8	-2
35	House Regulators	Meter & Regul Study	3,756	3,010	683	21	35	5	1
36	Rents	Customers	1,111	1,028	82	0	1	0	0
37	Dispatching	1/2 Dsgn Day, 1/2 Ei	3,009	1,302	756	86	101	165	598
38	Customer Installations	Customers	850	787	63	0	0	0	0
39	Other Distribution	Customers	9,573	8,857	708	3	5	1	0
40	Supervision & Engineerin	Dist Exp, w/o Sup &	7,887	5,896	1,208	94	93	147	450
41	Total Distribution Expense		39,553	29,567	6,057	471	464	739	2,255

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Operation & Maintenance (Pg 2 of 2)

	Cust Acctg & Inform	**Allocator**	**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
1	Acct Superv	Customers	1,346	1,245	100	0	1	0	0
2	Acct Meter Read	Customers	2,365	2,188	175	1	1	0	0
3	Acct Recrds & Coll	Record & Coll Study	6,140	5,443	398	106	169	19	6
4	Acct Uncollect	Uncollectibles Study	2,958	2,489	469	0	0	0	0
5	Acct Misc	Customers	77	72	6	0	0	0	0
6	Asst Expense (w/o CIP)	Cust Inform Study	910	669	204	13	21	2	1
7	Tot Cust Acctg & Inform		13,797	12,107	1,351	120	191	21	7
	Admin & General								
8	Property Insurance	Net Plant	748	505	148	12	10	15	58
9	Pension & Benefit-Direct	Labor	8,817	6,524	1,417	115	101	141	520
10	Salaries	Labor	7,320	5,416	1,176	95	84	117	432
11	Office & Supplies	Labor	4,592	3,398	738	60	52	73	271
12	Admin Transfer Credit	Labor	-5,649	-4,180	-908	-73	-65	-90	-333
13	Outside Services	Labor	1,571	1,163	253	20	18	25	93
14	Incentive Compensation	Labor	0	0	0	0	0	0	0
15	Injuries and Claims	1/2 Rt Base, 1/2 Pres	1,778	1,109	437	44	67	31	90
16	Regulatory Comm Exp	Pres Rev; Mod Pres	679	401	197	22	41	8	10
17	Contributions	Pres Rev; Mod Pres	0	0	0	0	0	0	0
18	General Advertising	1/2 Rt Base, 1/2 Pres	24	15	6	1	1	0	1
19	Misc General Exp	1/2 Rt Base, 1/2 Pres	195	122	48	5	7	3	10
20	Rents	1/2 Rt Base, 1/2 Pres	7,410	4,620	1,822	184	280	130	374
21	Maint of Gen Plt	1/2 Rt Base, 1/2 Pres	64	40	16	2	2	1	3
22	Total A & G Expense		27,550	19,131	5,351	485	599	456	1,527
	Amortizations								
23	CIP/DSM	Sales, W/o CIP Exem	28,618	14,547	8,676	1,078	2,923	1,320	74
24	Amortizations	Labor	926	685	149	12	11	15	55
25	Instructional Advertising	Pres Rev; Mod Pres	192	113	56	6	12	2	3
26	Total Amortizations		29,736	15,345	8,880	1,097	2,945	1,338	131
	Sales Expense								
27	Sales, Econ Dvlp & Other	Sales, W/ Transp	50	17	10	1	3	5	14
28	Total Sales Econ Dvlp & Other		50	17	10	1	3	5	14
29	**Total O&M Expense**		**469,670**	**273,807**	**138,865**	**15,829**	**32,517**	**2,741**	**5,912**
	Book Depreciation	**Allocator**							
30	**Production Plant (LPG)**	Design Day	4,793	2,546	1,455	154	0	31	607
31	**Storage Plant (LNG)**	Design Day	4,058	2,156	1,232	130	0	26	514
32	Transmission - Average C	Average and Peak	2,058	1,011	580	62	57	91	257
33	Transmission - Direct Ass	Direct Assign	362	0	0	0	0	0	362
34	**Transmission Plant**		2,420	1,011	580	62	57	91	619
	Distribution Plant								
35	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
36	Mains	Mains, Overall	24,072	16,074	4,748	434	400	632	1,785
37	Services	Service Study	12,959	11,234	1,653	18	48	4	1
38	Meters	Meter & Regul Study	4,895	3,924	890	28	45	7	2
39	House Regulators	Meter & Regul Study	894	717	163	5	8	1	0
40	Total Distribution Plant		42,820	31,949	7,453	485	502	644	1,788
41	**General & Common Plan**	Prod-Stor-Tran-Dis	19,431	13,417	3,769	297	239	344	1,365
42	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
43	**Total Book Deprec**		**73,521**	**51,079**	**14,489**	**1,128**	**798**	**1,136**	**4,892**

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	Real Estate & Prop Taxes	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	885	470	269	28	0	6	112
2	**Storage Plant (LNG)**	Design Day	0.0	0	0	0	0	0	0
3	Transmission - Average C	Average and Peak	1,088	535	307	33	30	48	136
4	Transmission - Direct Ass	Direct Assignment	205	0	0	0	0	0	205
5	**Transmission Plant**		1,293	535	307	33	30	48	341
	Distribution Plant								
6	Regulator Stations	Average and Peak	16,455	8,087	4,635	496	455	727	2,055
7	Mains	Mains, Overall	0	0	0	0	0	0	0
8	Services	Service Study	0	0	0	0	0	0	0
9	Meters	Meter & Regul Study	0	0	0	0	0	0	0
10	House Regulators	Meter & Regul Study	0	0	0	0	0	0	0
11	Total Distribution Plant		16,455	8,087	4,635	496	455	727	2,055
12	**General and Common Pl**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
13	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Total Rl Est & Prop Tax**		**18,633**	**9,092**	**5,210**	**558**	**485**	**781**	**2,508**
15	Payroll Taxes	Labor	3,427	2,536	551	45	39	55	202
16	**Tot Non-Income Taxes**		**22,060**	**11,628**	**5,761**	**602**	**524**	**836**	**2,710**
	Provision-Defer Inc Tax	**Allocator**							
17	**Production Plant (LPG)**	Design Day	240	128	73	8	0	2	30
18	**Storage Plant (LNG)**	Design Day	599	318	182	19	0	4	76
19	Transmission - Average C	Average and Peak	651	320	183	20	18	29	81
20	Transmission - Direct Ass	Direct Assign	29	0	0	0	0	0	29
21	**Transmission Plant**		681	320	183	20	18	29	111
	Distribution Plant								
22	Regulator Stations	Average and Peak	1	1	0	0	0	0	0
23	Mains	Mains, Overall	341	228	67	6	6	9	25
24	Services	Service Study	-398	-345	-51	-1	-1	0	0
25	Meters	Meter & Regul Study	1,012	812	184	6	9	1	0
26	House Regulators	Meter & Regul Study	160	128	29	1	1	0	0
27	Total Distribution Plant		1,117	823	230	12	15	11	26
28	**General and Common Pl**	Prod-Stor-Tran-Dis	3,039	2,098	589	46	37	54	213
29	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
30	Net Operating Loss (NOL	Net Plant	0	0	0	0	0	0	0
31	Non-Plant Related	Labor	112	83	18	1	1	2	7
32	**Tot Prov Defer Inc Tax**		**5,788**	**3,770**	**1,276**	**107**	**72**	**100**	**463**
	Investment Tax Credit	**Allocator**							
33	**Production Plant (LPG)**	Design Day	0	0	0	0	0	0	0
34	**Storage Plant (LNG)**	Design Day	-1	0	0	0	0	0	0
35	Transmission - Average C	Average and Peak	-5	-2	-1	0	0	0	-1
36	Transmission - Direct Ass	Direct Assign	0	0	0	0	0	0	0
37	**Transmission Plant**		-5	-2	-1	0	0	0	-1
	Distribution Plant								
38	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
39	Mains	Mains, Overall	-101	-67	-20	-2	-2	-3	-7
40	Services	Service Study	0	0	0	0	0	0	0
41	Meters	Meter & Regul Study	0	0	0	0	0	0	0
42	House Regulators	Meter & Regul Study	0	0	0	0	0	0	0
43	Total Distribution Plant		-101	-67	-20	-2	-2	-3	-7
44	**General and Common Pl**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
45	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
46	**Net Invest Tax Credit**		**-106**	**-70**	**-21**	**-2**	**-2**	**-3**	**-8**
47	**Total Operating Exp**		**570,932**	**340,214**	**160,368**	**17,664**	**33,909**	**4,809**	**13,968**
42a	**Pres Op Inc Before Inc Tax**		**51,105**	**27,627**	**19,686**	**2,254**	**3,727**	**2,635**	**-4,824**
42b	**Prop Op Inc Before Inc Tax**		**110,130**	**65,540**	**34,554**	**3,789**	**6,247**	**4,719**	**-4,719**

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1	**Production Plant (LPG)**	Design Day	5,994	3,184	1,820	192	0	39	759
2	**Storage Plant (LNG)**	Design Day	6,170	3,278	1,873	198	0	40	781
3	Transmission - Average C	Average and Peak	4,587	2,254	1,292	138	127	203	573
4	Transmission - Direct Ass	Direct Assign	537	0	0	0	0	0	537
5	**Transmission Plant**		5,124	2,254	1,292	138	127	203	1,110
	Distribution Plant								
6	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
7	Mains	Mains, Overall	34,141	22,798	6,734	615	567	896	2,531
8	Services	Service Study	8,514	7,382	1,086	12	32	2	1
9	Meters	Meter & Regul Study	8,054	6,456	1,464	46	75	11	3
10	House Regulators	Meter & Regul Study	1,221	979	222	7	11	2	0
11	Total Distribution Plant		51,931	37,614	9,506	680	685	912	2,535
12	**General and Common Pl**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
13	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	Net Operating Loss (NOL	Net Plant	34,159	23,049	6,772	563	457	680	2,638
15	**Total Tax Depreciation**		**103,378**	**69,379**	**21,263**	**1,772**	**1,268**	**1,873**	**7,823**
Present Return									
	Inc Tax Additions	**Allocator**							
16	Total Book Depr Exp		73,521	51,079	14,489	1,128	798	1,136	4,892
17	Provision for Deferred		5,788	3,770	1,276	107	72	100	463
18	Net Inv Tax Credit		-106	-70	-21	-2	-2	-3	-8
19	Avoided Tax Interest	CWIP	1,382	831	349	34	10	19	139
20	Total Tax Additions		80,584	55,610	16,092	1,267	878	1,252	5,485
	Inc Tax Deductions								
21	Tax Depr & Removal Exp		103,378	69,379	21,263	1,772	1,268	1,873	7,823
22	Debt Interest Expense	; Mod Rate Base	26,879	17,638	5,420	470	397	626	2,329
23	Other Timing Differences	Labor	-3,069	-2,271	-493	-40	-35	-49	-181
24	Meals	Labor	104	77	17	1	1	2	6
25	Total Tax Deductions		127,292	84,824	26,206	2,203	1,631	2,451	9,977
26a	**Pres Taxable Net Income**		**4,397**	**-1,587**	**9,572**	**1,318**	**2,975**	**1,436**	**-9,316**
26b	**Prop Taxable Net Income**		**63,423**	**36,326**	**24,439**	**2,853**	**5,495**	**3,520**	**-9,211**
27a	**Pres Inc Tax, @22.88%**		**1,006**	**-363**	**2,190**	**302**	**681**	**329**	**-2,132**
27b	**Prop Inc Tax, @28.34%**		**17,971**	**10,293**	**6,925**	**808**	**1,557**	**998**	**-2,610**
28a	**Pres Preliminary Return**		50,099	27,990	17,496	1,953	3,047	2,306	-2,693
28b	**Prop Preliminary Return**		92,159	55,246	27,629	2,981	4,691	3,721	-2,109
29	**Total AFUDC**	CWIP	**2,677**	**1,563**	**706**	**70**	**17**	**36**	**284**
30a	**Pres Total Return**	; Mod Rate Base	**52,776**	**29,553**	**18,202**	**2,023**	**3,064**	**2,342**	**-2,409**
30b	**Prop Total Return**	; Mod Rate Base	**94,836**	**56,809**	**28,335**	**3,051**	**4,708**	**3,757**	**-1,825**
31a	**Pres % Return on Rate Base**		**4.16%**	**3.55%**	**7.12%**	**9.13%**	**16.38%**	**7.94%**	**-2.19%**
31b	**Prop % Return on Rate Base**		**7.48%**	**6.83%**	**11.08%**	**13.78%**	**25.16%**	**12.73%**	**-1.66%**
32a	**Pres Common Return**		**25,897**	**11,915**	**12,783**	**1,553**	**2,667**	**1,716**	**(4,737)**
32b	**Prop Common Return**		**67,957**	**39,171**	**22,915**	**2,582**	**4,311**	**3,132**	**(4,154)**
33a	**Pres % Ret on Common Rt Bs**		**3.89%**	**2.73%**	**9.52%**	**13.36%**	**27.16%**	**11.08%**	**-8.21%**
33b	**Prop % Ret on Common Rt Bs**		**10.21%**	**8.97%**	**17.07%**	**22.20%**	**43.89%**	**20.22%**	**-7.20%**
AFUDC									
34	Production Plant (LPG)	Design Day	1,072	570	326	34	0	7	136
35	Storage Plant (LNG)	Design Day	504	268	153	16	0	3	64
36	Transmission - Average C	Average and Peak	155	76	44	5	4	7	19
37	Transmission - Direct Ass	Direct Assign	0	0	0	0	0	0	0
38	Transmission Plant	Average and Peak	155	76	44	5	4	7	19
	Distribution:								
39	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
40	Mains	Mains Overall	347	232	68	6	6	9	26
41	Services	Service Study	1	1	0	0	0	0	0
42	Meters	Meter & Regul Study	0	0	0	0	0	0	0
43	House Regulators	Meter & Regul Study	39	31	7	0	0	0	0
44	Total Distribution		387	264	76	6	6	9	26
45	General Plant	Prod-Stor-Tran-Dis	558	385	108	9	7	10	39
46	Gas Common	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
47	Total AFUDC		2,677	1,563	706	70	17	36	284
Labor Allocator		**Allocator**							
48	Customer Accounting	Customers	3,830	3,544	283	1	2	0	0
49	Cust Serv & Inform	Customers	753	696	56	0	0	0	0
50	Distribution	Dist Exp, w/o Sup &	23,334	17,443	3,573	278	274	436	1,330
51	Admin & General	Labor w/o A&G	15,438	11,423	2,481	201	176	247	910
52	Production	Other Production Ex	3,966	1,996	1,152	127	93	77	521
53	Sales	Sales, W/ Transp	0	0	0	0	0	0	0
54	Transmission	Design Day	421	223	128	14	0	3	53
55	Total		47,742	35,326	7,673	620	545	763	2,814

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	Internal Allocators	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**43.26%**	**25.14%**	**2.85%**	**3.37%**	**5.49%**	**19.88%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**62.34%**	**24.59%**	**2.48%**	**3.78%**	**1.76%**	**5.04%**
3	Average and Peak (Mains)	620,688	305,051	174,821	18,721	17,153	27,427	77,515
4	Average and Peak	**100.00%**	**49.15%**	**28.17%**	**3.02%**	**2.76%**	**4.42%**	**12.49%**
5	CWIP	**100.00%**	**60.16%**	**25.24%**	**2.46%**	**0.71%**	**1.39%**	**10.05%**
6	Dist Exp, w/o Sup & Eng	31,666	23,671	4,849	377	371	592	1,805
7	Dist Exp, w/o Sup & Eng	**100.00%**	**74.75%**	**15.31%**	**1.19%**	**1.17%**	**1.87%**	**5.70%**
8	Distribution Plant	**100.00%**	**73.03%**	**17.88%**	**1.27%**	**1.27%**	**1.73%**	**4.82%**
9	Gas Plant In Service	**100.00%**	**69.05%**	**19.40%**	**1.53%**	**1.23%**	**1.77%**	**7.03%**
10	Labor	**100.00%**	**73.99%**	**16.07%**	**1.30%**	**1.14%**	**1.60%**	**5.90%**
11	Mains, Overall	**100.00%**	**66.77%**	**19.72%**	**1.80%**	**1.66%**	**2.63%**	**7.41%**
12	Modified O&M Expense	459,328	267,388	136,283	15,566	32,106	2,563	5,422
13	Modified O&M Expense	**100.00%**	**58.21%**	**29.67%**	**3.39%**	**6.99%**	**0.56%**	**1.18%**
14	Net Plant	**100.00%**	**67.47%**	**19.83%**	**1.65%**	**1.34%**	**1.99%**	**7.72%**
15	Other Production Exp	**100.00%**	**50.33%**	**29.05%**	**3.21%**	**2.34%**	**1.95%**	**13.13%**
16	Prod-Stor-Tran-Dis	1,915,459	1,322,581	371,520	29,270	23,604	33,923	134,563
17	Prod-Stor-Tran-Dis	**100.00%**	**69.05%**	**19.40%**	**1.53%**	**1.23%**	**1.77%**	**7.03%**
18	Rate Base	**100.00%**	**65.62%**	**20.16%**	**1.75%**	**1.48%**	**2.33%**	**8.66%**
19	Rt Base, w/o Work Cash	1,277,861	837,813	258,624	22,487	19,409	29,563	109,965
20	Rt Base, w/o Work Cash	**100.00%**	**65.56%**	**20.24%**	**1.76%**	**1.52%**	**2.31%**	**8.61%**
21	Transmission & Distribution	1,746,062	1,232,583	320,094	23,832	23,604	32,832	113,118
22	Tran & Distrib	**100.00%**	**70.59%**	**18.33%**	**1.36%**	**1.35%**	**1.88%**	**6.48%**
23	Labor w/o A&G	32,304	23,903	5,192	420	369	516	1,904
24	Labor w/o A&G	**100.00%**	**73.99%**	**16.07%**	**1.30%**	**1.14%**	**1.60%**	**5.90%**
	Component Allocators							
25	Mod Present Rev	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
26	Mod Rate Base	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
27	1/2 Mod Rt Bs, 1/2 Mod Pres Rv	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**

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External Allocators

	Customer-Related	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Bills	5,888,101	5,447,768	435,333	1,761	2,819	312	108
2	Modified Bills	5,888,077	5,447,768	435,333	1,761	2,819	312	84
3	Meter & Regul Weightings		1.00					
4	Meter (Wtd Bills)	6,796,277	5,447,768	1,235,244	38,547	63,096	9,382	2,241
5	Service Weightings		1.00					
6	Service (Wtd Bills)	6,283,854	5,447,768	801,596	8,759	23,471	1,787	472
7	Records & Collect Weightings		1.00					
8	Records & Collect (Wtd Bills)	6,146,025	5,447,768	398,257	105,660	169,140	18,720	6,480
9	Cust Information Weightings		1.00					
10	Cust Information (Wtd Bills)	7,403,799	5,447,768	1,658,191	105,660	168,060	17,640	6,480
11	Customers	100.00%	92.52%	7.39%	0.03%	0.05%	0.01%	0.00%
12	Modified Customers	100.00%	92.52%	7.39%	0.03%	0.05%	0.01%	0.00%
13	Meter & Regul Study	100.00%	80.16%	18.18%	0.57%	0.93%	0.14%	0.03%
14	Service Study	100.00%	86.69%	12.76%	0.14%	0.37%	0.03%	0.01%
15	Record & Coll Study	100.00%	88.64%	6.48%	1.72%	2.75%	0.30%	0.11%
16	Cust Inform Study	100.00%	73.58%	22.40%	1.43%	2.27%	0.24%	0.09%
	Energy-Related							
17	Cal Yr Sales Dkt, W/o Trans	74,524,637	39,670,184	23,667,033	2,968,555	8,003,112	0	215,753
18	Transportation Dkt	44,254,025	0	0	0	0	12,284,918	31,969,107
19	Cal Yr Sales Dkt, W/ Trans	118,778,662	39,670,184	23,667,033	2,968,555	8,003,112	12,284,918	32,184,860
20	CIP Exempt Dkt	40,734,453	0	7,196	27,447	32,025	8,683,903	31,983,882
21	Sales Dkt, W/o CIP Exempt	78,044,208	39,670,184	23,659,837	2,941,107	7,971,087	3,601,015	200,978
22	Sales, W/o Transp	100.00%	53.23%	31.76%	3.98%	10.74%	0.00%	0.29%
23	Sales, W/ Transp	100.00%	33.40%	19.93%	2.50%	6.74%	10.34%	27.10%
24	Sales, W/o CIP Exempt	100.00%	50.83%	30.32%	3.77%	10.21%	4.61%	0.26%
25	Modified Sales W/Transport	100.00%	37.84%	22.57%	2.83%	7.63%	11.72%	17.40%
	Demand-Related							
26	Design Day Demand (Retail)	898,926	477,582	272,900	28,854	0	5,790	113,800
27	Avg Daily Firm Dkt, W/ Trans	273,201	108,685	64,841	8,133	0	3,950	87,591
28	Design Day	100.00%	53.13%	30.36%	3.21%	0.00%	0.64%	12.66%
29	Excess Design Day	100.00%	55.56%	31.34%	3.12%	0.00%	0.28%	9.70%
	Miscellaneous (only alloc to class, not component)							
30	Present Retail Revenue	617,806	364,900	179,310	19,847	37,592	7,374	8,783
31	Uncollectibles Study	100.00%	84.15%	15.85%	0.00%	0.00%	0.00%	0.00%
32	Present Retail Revenue	100.00%	59.06%	29.02%	3.21%	6.08%	1.19%	1.42%
33	Late Payment Penalty	100.00%	92.77%	6.61%	0.26%	0.36%	0.00%	0.00%

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Capital Structure		Rate	Ratio	Wtd Cost
1	Long Term Debt	4.46%	46.87%	2.09%
2	Short Term Debt	5.01%	0.63%	0.03%
3	Debt Total	4.46%	47.50%	2.12%
4	Preferred Stock	0.00%	0.00%	0.00%
5	Common Equity	10.20%	52.50%	5.36%
6	Required Rate of Return		100.00%	7.48%
7	MN Combined State & Fed Tax Rate (Includes Tax Credits)			28.34%
8	1 / (1 - Tax Rate) Factor			139.54%
9	Tax Rate / (1 - Tax Rate) Factor			39.54%

OTHER SUPPLEMENTAL INFORMATION
(Part 7825.4400)

The following supplemental information as required by parts 7825.3800 and 7825.4400 shall be filed:

A. Annual report to stockholders or members including financial statements and statistical supplements for the most recent fiscal year. If a utility is not audited by an independent public accountant, unaudited financial statements will satisfy this filing requirement.

B. For investor-owned utilities only, a schedule showing the development of the gross revenue conversion factor.

ANNUAL

BUILDING THE FUTURE

Xcel Energy®

2022
ANNUAL REPORT

COMPANY DESCRIPTION

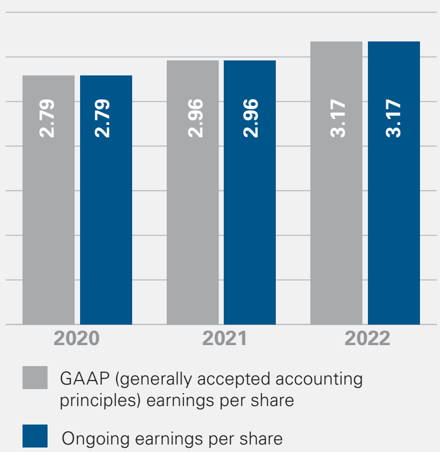
Xcel Energy is a major U.S. electric and natural gas company with annual revenues of $15.3 billion. Based in Minneapolis, Minnesota, the company operates in eight states and provides a comprehensive portfolio of energy-related products and services to 3.8 million electricity customers and 2.1 million natural gas customers.

FINANCIAL HIGHLIGHTS

	2021	2022
Total GAAP earnings per share	2.96	3.17
Ongoing earnings per share	2.96	3.17
Dividends annualized	1.83	1.95
Stock price (close)	67.70	70.11
Assets (millions)	57,851	61,188

EARNINGS PER SHARE

Dollars per share (diluted)



ON THE COVER:
Lineman during construction of new Xcel Energy transmission lines in Wisconsin. Transmission development is essential to accelerating clean energy growth.

To my fellow customers and shareholders

Bob Frenzel
Chairman, President and Chief Executive Officer

Despite historic headwinds for the industry in 2022, Xcel Energy continued its record of providing our communities with safe, reliable energy while charting a course for a clean energy future. As always, in 2022 we were there for our customers when they needed us most while continuing our track record of strong financial results for our shareholders.

We are in a remarkable time. It's the most exciting and dynamic period in our industry since Tesla and Edison competed for intellectual dominance in the Current Wars more than a century ago. The changes we see today are equally consequential. But despite the extraordinary times in which we do business, we never lose sight of the experience and day-to-day needs of our customers.

I believe this is what has made Xcel Energy successful. In 2022, we continued to lead the clean energy transition while delivering our 18th straight year of consistent results for shareholders and keeping our customers' bills low. We are committed to shaping an energy future that is sustainable in every way: it delivers clean, carbon-free energy to customers; it is safe, reliable and affordable for communities; and it generates opportunity and prosperity for all.

But we also know the path to get there needs to be equally sustainable, making consistent progress toward our goals while never straying from delivering the core values of our customers, policymakers and other stakeholders: that our energy is always reliable and affordable while meeting our customers' changing energy needs.

We seek to be trusted for the strength of the service we provide — and preferred for our commitment to our customers and clean energy leadership. This is how we will build an energy future that powers economic prosperity and social progress for another 100+ years.

Expanding our clean energy vision

True to our commitment to lead, we expanded our goal for clean energy in 2022 and became the first major U.S. energy provider to include a net-zero carbon emission footprint for all the energy our customers use in our service territory: electricity, gas and transportation. Consistent with our approach to leadership, this expanded goal is informed by climate science and grounded in clean technology — both the renewable energy we will build today and the advanced technologies we will explore in the future.

Committed to our communities and customers

2022 saw customers across the country struggling with the dual pressures of lingering pandemic-related financial challenges and a global spike in natural gas commodity prices. Our commitment to our customers and keeping bills low remains as strong as ever, which is why Xcel Energy expanded both our financial support programs and direct outreach campaign to connect customers with the greatest need to public energy assistance. As a result, Xcel Energy customers accessed more than $200 million from public assistance and company programs combined last year.

At the same time, 2022 was a particularly volatile weather year, with extreme temperatures in both heating and cooling seasons and an active storm season. Throughout, our customers experienced one of the highest levels of energy reliability in the country. Reliability and affordability are core values we will never stray from, and I am extremely proud of this continued focus on the vitality and financial stability of our customers and communities.

Enabling a rapidly maturing EV market

Xcel Energy paid significant attention in 2022 to developing the expertise and infrastructure to assure electric vehicle (EV) ownership is accessible and attractive to customers. We moved forward with a multi-jurisdictional package of EV programs that addresses all our major customer segments. We proposed to invest $325 million in EV programs, and we obtained approval for Xcel Energy-owned high-speed public charging in Minnesota, New Mexico and Colorado.

Building our safety culture

Safety remains our number one priority, and our focus on continuous improvement through learning is taking hold. Under our Safety Always program, employees are encouraged to identify, discuss and learn from safety events that could have resulted in serious injuries or fatalities. As a result of this program, near-miss event reporting last year was up 19% from 2020 levels. And we are constantly training, with 15,000 individual employees and contractors receiving Critical Risk Management training and hazard identification while achieving 98% contractor compliance with Safety Always orientation. However, the tragic deaths of two contractors working at our Comanche generating plant last summer remind us that our safety work is never done. We must be tireless in our vigilance.

Making the clean energy future a reality

Last year saw us achieve important milestones in the journey to make our clean energy vision a reality with exciting new opportunities for partnerships and investment:

- We reached 53% carbon reduction from 2005 levels on our electric grid while remaining a top quartile energy provider in reliability.
- We worked to support new federal clean energy incentives and policy reforms in the Inflation Reduction Act that help pave the way for our clean energy strategy and removed some of the barriers to utility ownership of renewable energy resources.
- We led the way in unlocking the full potential of the country's abundant renewable energy, securing approvals for major new transmission projects in both Colorado and the Upper Midwest.
- Our regulators approved our clean energy plans in Minnesota and Colorado, paving the way for nearly 10 gigawatts of additional renewables and the construction of significant new transmission to support our clean energy strategy.
- We received final approvals to move forward with the Sherco Solar project which, when complete, will convert a coal generation facility into one of the largest solar generation facilities in the country.

- We launched our new Clean Fuels initiative to drive the innovations that will deliver zero- or low-carbon fuel sources to homes, transportation and generating facilities. This includes new demonstration projects to generate hydrogen commercially with carbon-free electricity.

Serving ethically and equitably

As we lead the way to an economy powered by clean, carbon-free energy, we will continue to be responsible stewards of the health, well-being, and economic opportunity of all the communities we serve. It starts with our own company, and I am pleased with our continued progress toward a diverse leadership team and workforce. The company's executive leadership became more diverse over the course of 2022, and we again exceeded our corporate targets on diversity, equity and inclusion.

At the same time, we are investing in partnerships to expand a workforce trained in clean energy jobs that is reflective of all the communities we serve. Our customer programs have a strong focus on equitable outreach to low-income communities, including several innovative concepts in our EV partnerships and programs. We are committed to ensuring the prosperity and opportunity of the clean energy transition is shared by all.

As a result of our commitment to our customers, communities and employees, Xcel Energy was again recognized as one of *Fortune* magazine's World's Most Admired Companies and is listed among the World's Most Ethical Companies® by Ethisphere. We also earned recognition for being one of the best places to work for veterans, for disability inclusion and for LGBTQ+ equality.

The promise of a clean energy future is quickly becoming reality, and Xcel Energy will remain on the forefront of building this future. I am confident that we will continue to be the trusted and preferred energy partner for our customers. Thank you for the continued trust you place in us.

Sincerely,

Bob Frenzel
Chairman, President and
Chief Executive Officer

OUR CLEAN ENERGY VISION: NET-ZERO CARBON EMISSIONS FOR **ALL** ENERGY

Xcel Energy is committed to leading the clean energy transition. In 2022, we took this charge one step further, becoming the first major U.S. energy company to set a goal to enable a comprehensive net-zero carbon energy economy in our service territory. We expanded our industry-leading pledge from 2018 for 100% carbon-free electricity by 2050 to include transportation and net-zero targets for gas.

Our transportation vision builds on an initial target with a new goal of enabling one out of five vehicles in the areas we serve to be electric by 2030. In addition to delivering clean, carbon-free power to charging points, we will actively contribute to the buildout of necessary infrastructure, support customers with effective programs to manage charging at home and help business electrify their vehicle fleets.

Our vision for net-zero gas service acknowledges that electrifying home heating, cooking and other appliances powered by natural gas is not the right choice for every customer, so we are taking responsibility for delivering safe, reliable and affordable energy that minimizes the impact to customers while still achieving the environmental targets they value.

We will continue building a world-class energy infrastructure while providing sustainability, energy security and economic prosperity for our customers, always striving to be the preferred and trusted provider of energy for the communities we serve.

While we're thrilled with this progress, we know there's still a long way to go. Leading this transition will take operational excellence, strong stakeholder engagement and regulatory effectiveness, and a balanced, thoughtful approach to drive carbon reductions while continuing to ensure reliability and affordability for our customers.

We invite you to join us as we harness the power of innovation to meet the needs of the electric system of the future, delivering energy that is affordable, reliable, safe and sustainable.

INVESTING IN OUR COMMUNITIES AND CUSTOMERS

XCEL ENERGY IS PARTNERING WITH COMMUNITIES TO BUILD THE ENERGY FUTURE, SUPPORTING OUR CUSTOMERS AND GROWING A CLEAN ENERGY WORKFORCE

Our customers trust Xcel Energy will be there for them.

We demonstrate that commitment every time our trucks roll for storm response; every time our crews relight customers after a gas event; every time we deliver service that empowers customers to achieve their personal energy goals.

We also build trust in how we give back. Last year, we served more than 3 million electric customers and 2 million natural gas customers with the energy that powers their lives, livelihoods and celebrations.

Through the Xcel Energy Foundation, we granted $4.4 million to 426 nonprofits in 2022. Thanks to our giving, 820,000 students will receive hands-on STEM learning, including 380,000 female learners; 11,000 trees will be planted, offsetting 7,800 tons of carbon emissions; and 8,000 individuals will gain employment, generating $260 million in wages.

Beyond this, our team's generosity to local communities changed lives and demonstrated the power of our values. Through our annual United Way Giving Campaign, we raised more than $5 million, and on our Day of Service, we contributed 9,000 volunteer hours. Since 2020, we've donated more than $30 million across our eight states through giving and volunteering.

Meeting our customers' needs: today and in the future

Economic hardships have been challenging for customers throughout our footprint. But we want to ensure our energy brings prosperity and opportunity today, and in the future.

> "Xcel Energy and its partners are connecting a new, diverse generation of bright students to be a part of leading the transition to a clean energy future."
>
> **Patricia Correa, Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer**

In late 2022, as natural gas commodity prices rose to historic highs, our Customer Care team responded quickly to connect customers with public energy assistance. Ultimately, they helped connect nearly 200,000 customers — from New Mexico to Michigan — with more than $200 million in assistance that reduced or entirely paid for their energy bills. Hard-hit Colorado customers alone received more than $87 million.

"We acted to reach out to customers of all backgrounds needing additional support to help them access energy assistance funds," said Brett C. Carter, executive vice president and group president, Utilities and chief customer officer. "Our agents stayed on the phone, sometimes for over an hour, to ensure their applications went through."

We know these challenges and volatility also underscore the importance of one of our key strategic priorities: leading the clean energy transition. In the last five years, our wind energy investments have saved customers nearly $3 billion.

For Xcel Energy, the future is about energy security and economic prosperity for our customers. As we look toward the future, we will meet the needs of the electric system of the future that is affordable, reliable, safe and clean, while never losing sight of our highest priority: customers.

Developing tomorrow's workforce

Xcel Energy's commitment to its communities goes beyond our customers. Much of our workforce comes right from the neighborhoods we serve, and as we lead the clean energy transition, we are committed to building a workforce of tomorrow reflective of those communities.

A central pillar of this commitment is reaching out through partnerships with local nonprofits and the education system to expose students to energy careers early, and to create new training programs in locations underserved with energy technical programs. One example is the Energy Careers Academy — a partnership with the Minnesota State Energy Center of Excellence — through which we work together to engage students with diverse backgrounds in energy-related fields of study.

"Xcel Energy and its partners are connecting a new, diverse generation of bright students to be a part of leading the transition to a clean energy future," said Patricia Correa, senior vice president, Human Resources & Employee Services and chief human resources officer.

The success of the clean energy transition will be tied to the success of connecting all our communities to its promise, and we're proud of our work to build that reality.

The speed of the country's transition to a clean energy future will be limited by national transmission infrastructure that currently operates at or near top capacity, unless the network grows at a much higher rate.

Xcel Energy intends to lead that acceleration.

A recent study from Princeton University estimated that to realize the total potential greenhouse gas emission reduction possible over the next decade, U.S. transmission infrastructure would need to expand at more than double its current pace. This is notable because while the vast majority of the public attention on the clean energy transition focuses on flashy topics like renewable generation development, long-duration storage and electrification, the nation's transmission infrastructure will truly be a keystone for the success of a zero-carbon energy economy.

"We are tapping into one of the richest wind energy resources in the world, capable of delivering clean, low-cost energy to not only our customers but areas poor in carbon-free energy sources," said Tim O'Connor, executive vice president and chief operations officer. "We've already saved our customers more than $3 billion through our wind energy investments, benefits we look to grow by expanding the capacity to transport the energy potential of the Great Plains and the Southwest with our transmission development plans."

In 2022, Xcel Energy achieved key milestones in its transmission infrastructure development plan with approvals of marquee proposals in the Upper Midwest and Colorado representing more than $3 billion in new investment. The Colorado Power Pathway project and the Upper Midwest projects are initial steps in a five-year, $7.4 billion transmission development plan to reduce congestion and increase regional reliability while connecting tens of thousands of megawatts (MW) of new renewable energy generation over the same period.

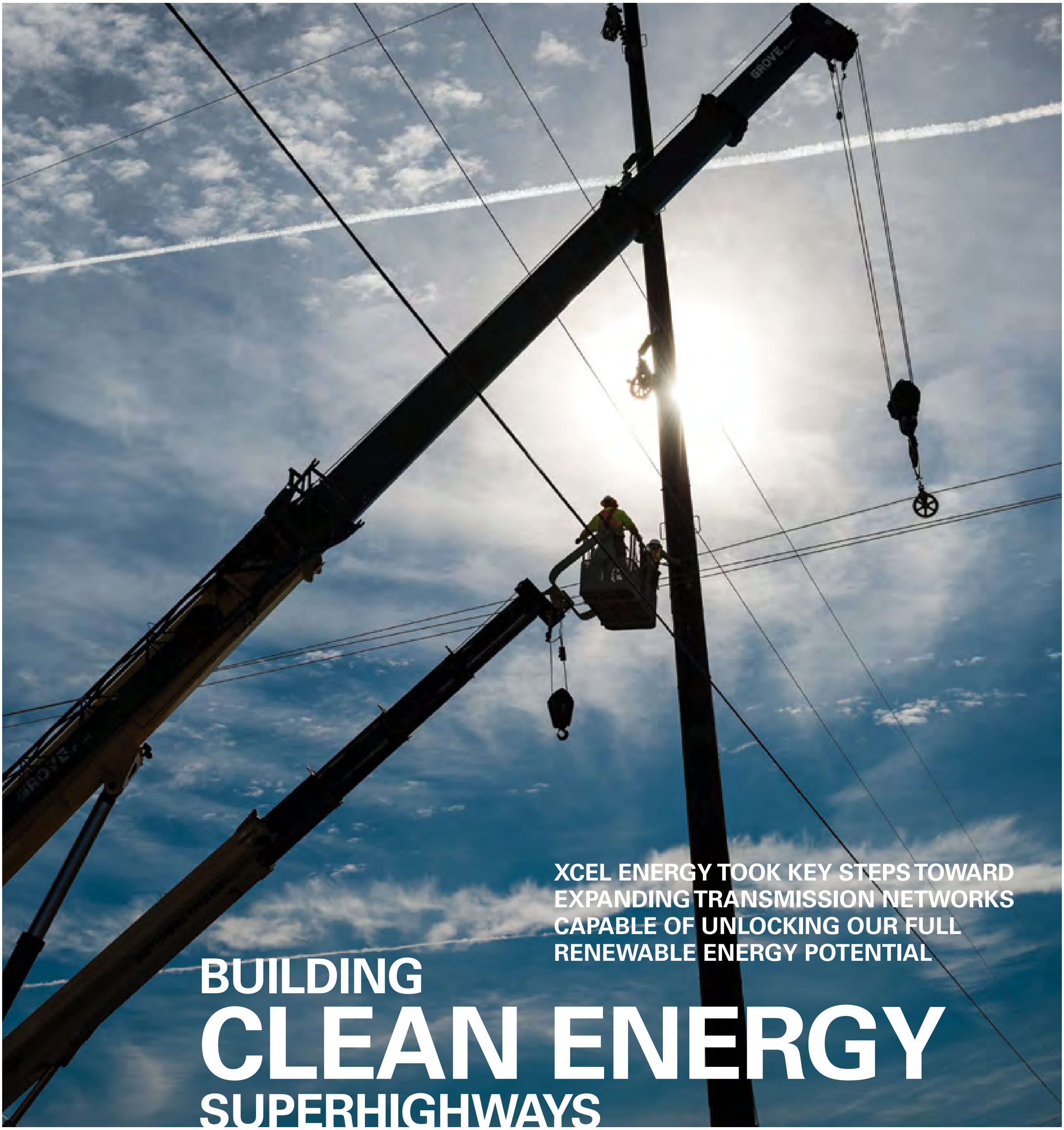
> "We're moving forward building an electric transmission network for the future, to deliver the energy economy of the future."
>
> **Michael Lamb, Senior Vice President, Transmission**

"The capacity constraints already limit the total potential benefit of existing renewable generation, with forced curtailment and congestion issues occurring across systems," said Michael Lamb, senior vice president, Transmission. "We're moving forward building an electric transmission network for the future, to deliver the energy economy of the future."

The Colorado and Upper Midwest transmission projects will add more than 1,000 miles of lines and several new or expanded substations. In Colorado, the new lines will create essential connections between communities and key development areas for wind and solar generation. The more than 500 miles of new high-voltage transmission will provide greater reliability for the overall grid, connecting more generation sources — a broader mix of generation to reduce issues with the intermittency of renewable generation — while making it easier to move power from where it's being generated to where it's most needed.

Xcel Energy's Upper Midwest plans are just one part of a more than $10 billion regional transmission plan to reduce congestion and increase grid reliability by 2030. Similar to the Colorado plan, five new projects will stretch from the South Dakota-Minnesota border to central Wisconsin, expanding the capacity to move energy from the wind-rich regions of western Minnesota and the eastern Dakotas to communities across the Upper Midwest and helping to unlock the full potential of this tremendous resource.

"This isn't just a grid management operation," said Lamb. "It's part of bringing the economic potential of a clean energy future to life and enabling the regions we serve to reap the full benefits of this unique global resource. It will drive local investment and economic development, overall energy savings and jobs."



XCEL ENERGY TOOK KEY STEPS TOWARD EXPANDING TRANSMISSION NETWORKS CAPABLE OF UNLOCKING OUR FULL RENEWABLE ENERGY POTENTIAL

BUILDING CLEAN ENERGY SUPERHIGHWAYS

BLUEPRINTS FOR HISTORIC RENEWABLE ENERGY EXPANSION

FROM PLEDGE TO PLAN, A COURSE TO OUR CLEAN ENERGY TARGET IS NOW MAPPED OUT

"Sherco Solar will drive reinvestment, sustain jobs and create new opportunities on land that Xcel Energy has owned and operated in Benton County for decades."

Chris Clark, President, Xcel Energy–Minnesota, North Dakota and South Dakota

Today, Xcel Energy customers receive 23% of their power from coal-fired generators. By year-end 2030, that figure will be zero.

That's because in 2022, Xcel Energy filed proposals with the New Mexico Public Utilities Commission that included a provision to move up the retirement date of coal-fired generation at its Tolk Generating Station. If approved, the company will be coal-free within seven years.

Coal's retirement closes one chapter in Xcel Energy's history as another opens. For more than a century, this fuel and thousands of workers at our plants powered millions of homes and businesses, helping to drive America's rise as a superpower and a global leader for economic opportunity. But as we noted in our 2018 pledge to deliver carbon-free electricity to our customers by 2050, technological innovation and new scientific observations create fresh opportunities to deliver the energy our customers demand. Today, we are building on the strengths of our energy legacy and tapping into the next great domestic energy sources: renewable wind and solar power.

"We have the tremendous opportunity and responsibility to develop some of the world's greatest potential sources of wind and solar energy."

Brett C. Carter, Executive Vice President and Group President, Utilities and Chief Customer Officer

Last year, Xcel Energy delivered on commitments to lay out our specific plans to reach the first milestone on the path to a 2050 target: by 2030, achieve an 80% reduction of carbon-emissions over 2005 levels. Plans filed and approved in our Upper Midwest Region and Colorado call for Xcel Energy to add nearly 10,000 MW of renewable energy capacity over the next 10 years.

"We have the tremendous opportunity and responsibility to develop some of the world's greatest potential sources of wind and solar energy," said Brett C. Carter, executive vice president and group president, Utilities and chief customer officer. "Through our commitment to customers and an equitable clean energy future, this won't just be a watershed moment for the energy industry but for the collective economies of the regions we serve."

Xcel Energy's plans call for adding an additional 24,500 MW of wind energy to its wind portfolio, which already is among the nation's largest and has saved customers more than $3 billion over the past five years in avoided fuel costs and other savings.

Excitingly, the plans approved in 2022 identify the largest expansion of solar energy generation in the company's history, 4,100 MW of large-scale solar. New solar projects are particularly exciting for their potential to play a role in redeveloping former coal operating facilities like the Sherco site in Minnesota, where all coal-fired operations are scheduled to retire by 2030.

"Sherco Solar will drive reinvestment, sustain jobs and create new opportunities on land that Xcel Energy has owned and operated in Benton County for decades," said Chris Clark, President, Xcel Energy–Minnesota, North Dakota and South Dakota. "When the project is completed in 2025, it will be one of the largest solar generating facilities in the country at 460 MW, creating more than 900 construction jobs and an estimated $240 million in local economic benefit."

Xcel Energy's plans for the Sherco Solar project received final approval in 2022 and will be one of the company's marquee renewable energy development initiatives over the next several years.

From 80% to 100%: that is the puzzle Xcel Energy, our peer energy providers, engineers, scientists, entrepreneurs, policy makers and many more stakeholders across the global community are working to solve.

There is broad consensus that existing generation and grid technologies will support an electrical grid with carbon emissions 80% lower than 2005 levels. There is also broad consensus that making the jump to a 100% carbon-free electrical grid — even more so an entire net-zero energy economy as Xcel Energy has pledged for its service territory — while maintaining the reliability, resiliency and affordability necessary to sustain it will require new approaches and technologies, some of which have yet to be invented.

Xcel Energy has always been an active partner in bridging that gap and putting real skin in the game, from committing its company leadership and experts to industry collaboration efforts, to co-launching and investing in venture funds dedicated to clean energy innovation. Now, some of the most promising emerging segments of a future energy economy are reaching the point of field demonstration, and Xcel Energy is again on the leading edge.

"There is a hotbed of activity in energy innovation, with many promising technologies to address some of the key barriers to a sustainable clean energy economy on the cusp of emerging," said Justin Tomljanovic, vice president, Corporate Development for Xcel Energy. "Within the next several years, I expect we'll see a sharp increase in grid-scale test cases, and it's important to us that Xcel Energy is actively involved in developing the most promising concepts."

> "Within the next several years, I expect we'll see a sharp increase in grid-scale and distribution-level test cases, and it's important to us that Xcel Energy is actively involved in developing the most promising concepts."
>
> **Justin Tomljanovic, Vice President, Corporate Development**

Three initiatives that will enable Xcel Energy's pledges to a net-zero carbon future across three energy markets warrant particular attention: fleet electrification, long-duration storage and zero- or low-carbon fuels.

Fleet electrification

This last summer, Xcel Energy introduced the country's first all-electric utility bucket truck, an important milestone in its own fleet electrification progress that offers a valuable testing ground for electric fleet vehicles performing light- to heavy-duty work. Medium- to heavy-duty fleet conversion has larger question marks in its future than the light-duty market, but also significant potential for both impactful carbon emission reductions and new grid management capabilities such as on-site or local resiliency support.

Long-duration storage

Expanding the amount of renewable energy powering the grid comes hand in hand with solving for greater generation intermittency when the sun doesn't shine or the wind doesn't blow. Even with significant expansions of distributed generation sources like rooftop solar, the grid will always require dispatchable power sources to protect the grid, communities and customers. Developing effective long-duration storage solutions to capture excess renewable energy to deploy when demand is higher is essential to a clean energy future.

That excess energy exists even today. In 2022, Xcel Energy alone curtailed enough wind energy during low-demand periods to power more than 75,000 homes. As renewable energy generation expands, this excess capacity will only grow. This is why Xcel Energy developed a partnership with Form Energy to be one of the first to deploy its 100-hour storage iron-air battery technology at sites in Colorado and Minnesota as demonstration projects to test its capabilities in the field. This is one of the most promising alternatives to lithium batteries, which are more expensive and less sustainable for the environment.

NEW INNOVATION PROJECTS MAY HOLD KEYS TO THE CLEAN ENERGY FUTURE

BRIDGING THE GAP TO 100%

These demonstrations will provide valuable data to further develop their viability for implementation.

Clean Fuels

Today, natural gas is an essential component for the energy our customers rely on. Nearly 85% of Xcel Energy's customers rely on natural gas for heating their homes or businesses, and natural gas generated 24% of the electricity we produced in 2022. Electrification of residential heating and cooling and the expansion of renewable generation will reduce these figures, but it's also a reality that both the costs to transition that much infrastructure and an interest in accelerating carbon emissions reductions mean that building a clean energy future requires innovation in the fuels we use for natural gas service and power generation.

Our Clean Fuels initiative leads the effort on this and took important steps in 2022 to make lower-carbon gas a reality. Much of the focus today is on the potential for hydrogen, which not only burns with no carbon emissions, but can be produced in a carbon-free process using renewable or nuclear energy. Projects are in development for several hydrogen use and production demonstrations, including test burns in electric generating plants, blending demonstrations for residential service and a production demonstration project at our Prairie Island Nuclear Generating Station in conjunction with the Idaho National Lab.

"The environmental and economic opportunities with hydrogen are tremendous and could be an essential resource for our customers to participate in a clean energy future without costly and disruptive changes to their lifestyle," said Greg Chamberlain, vice president, Clean Fuels. "We have some of the best performing wind, nuclear and gas operations, which we can leverage to lead the way on lower-carbon gas."

Xcel Energy's commitment to lead means a commitment to leading the innovation which will enable a safe, reliable and affordable clean energy future.

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, 2022 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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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, 2022, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $38,692,119,433.

As of Feb. 16, 2023, there were 549,847,034 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement for its 2023 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

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
MPCA	Minnesota Pollution Control Agency
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
SDPUC	South Dakota Public Utility Commission
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
RES	Renewable energy standard

Other

AFUDC	Allowance for funds used during construction
AMT	Alternative minimum tax
ALJ	Administrative Law Judge
ARO	Asset retirement obligation
ASC	Financial Accounting Standards Board Accounting Standards Codification
ATM	At-the-market
BART	Best available retrofit technology
C&I	Commercial and Industrial
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
CON	Certificate of Need
CSPV	Crystalline Silicon Photovoltaic
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
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
ETR	Effective tax rate
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
IPP	Independent power producing entity
IRA	Inflation Reduction Act
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.
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
NOx	Nitrogen Oxides
O&M	Operating and maintenance
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
RFP	Request for proposal
ROE	Return on equity
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCA	Transmission cost adjustment

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
WACC	Weighted Average Cost of Capital

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 through its website, free of charge, 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 2023 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, 2022 (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), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: 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; our ability to recover costs and our subsidiaries' ability to recover costs from customers; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including recessionary conditions, 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; uncertainty regarding epidemics, the duration and magnitude of business restrictions including shutdowns (domestically and globally), the potential impact on the workforce, including shortages of employees or third-party contractors due to quarantine policies, vaccination requirements or government restrictions, impacts on the transportation of goods and the generalized impact on the economy; 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 events; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties; regulatory changes and/or limitations related to the use of natural gas as an energy source; challenging labor market conditions and our ability to attract and retain a qualified workforce; and our ability to execute on our strategies or achieve expectations related to environmental, social and governance matters including as a result of evolving legal, regulatory and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets.

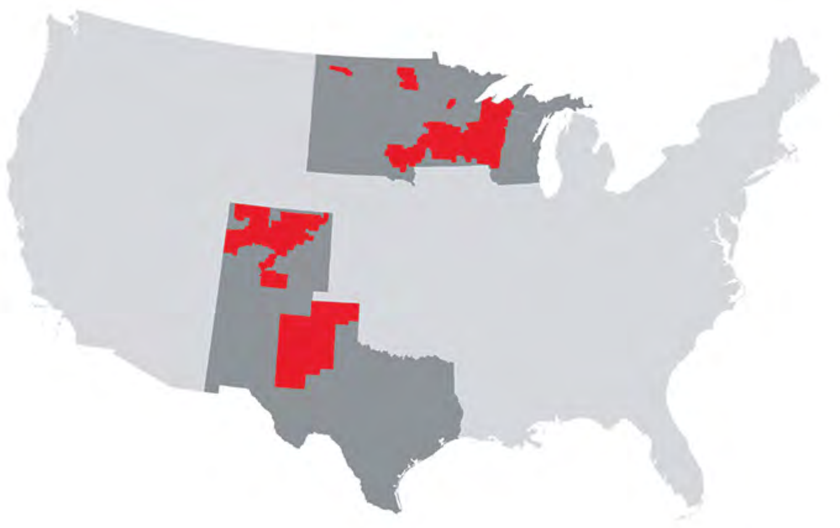
Overview

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). The Company serves customers in eight 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 3.8 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. The Company's nonregulated subsidiaries include Eloigne, Capital Services, Venture Holdings and Nicollet Project Holdings.

Subsidiary / Affiliate	Function
NSP-Minnesota	Electric & Gas
NSP-Wisconsin	Electric & Gas
PSCo	Electric & Gas
SPS	Electric
WGI	Interstate gas pipeline
WYCO	Gas storage and transportation
Other Subsidiaries	See Note 1 to the consolidated financial statements for further information

Utility Subsidiary Overview	
Electric customers	3.8 million
Natural gas customers	2.1 million
Total assets	$61.1 billion
Electric generating capacity	20,897 MW
Natural gas storage capacity	53.5 Bcf
Electric transmission lines (conductor miles)	110,000 miles
Electric distribution lines (conductor miles)	213,000 miles
Natural gas transmission lines	2,200 miles
Natural gas distribution lines	37,000 miles

Service Territory



Strategy

Xcel Energy's vision is to be the preferred and trusted provider of the energy our customers need. We will deliver on this vision while offering a competitive total return to shareholders. Our mission is to provide our customers with safe, clean, reliable energy services they want and value at a competitive price.

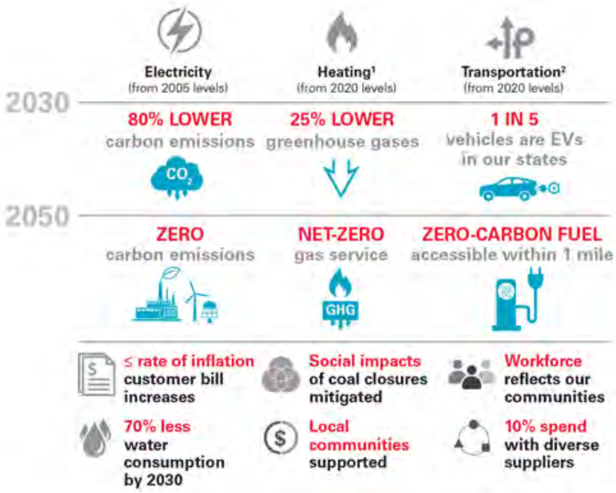
We execute on our vision and mission through three strategic priorities.

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

Our employees are guided by our four corporate values: Connected, Committed, Safe, and Trustworthy.

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.

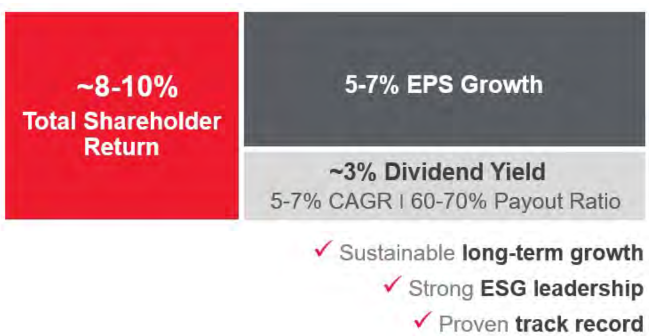
Our sustainability and Environmental, Social and Governance commitments are summarized as follows:



(1) Spans natural gas supply, delivery and customer use.
(2) Includes the Xcel Energy fleet; zero-carbon fuel is electricity or other clean energy.

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 18 consecutive years and delivering dividend growth for 19 consecutive years.

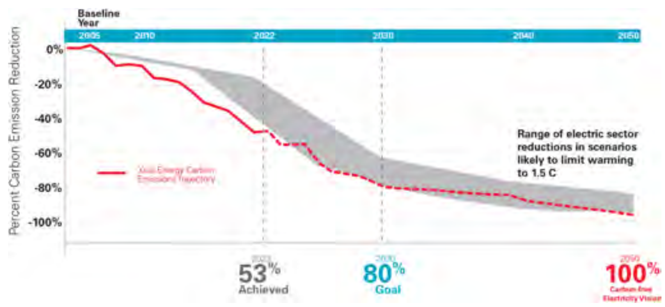
Over the past five years, GAAP earnings per share have grown by 7.1% annually and our annual dividend growth was 6.3%. Xcel Energy works to maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range. Current ratings are consistent with this goal.

LEAD THE CLEAN ENERGY TRANSITION

For nearly two decades, Xcel Energy has proactively managed the risk of climate change and worked to meet increasing demand for cleaner energy.

Carbon-free Electricity by 2050

In 2018, Xcel Energy became the first U.S. utility to establish a carbon-free vision, targeting 100% carbon-free electricity by 2050 with an interim goal to reduce carbon emissions 80% by 2030 (from 2005 levels), including owned and purchased power. A lead author for the climate change scientific analysis issued by the Intergovernmental Panel on Climate Change 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 approved resource plans outline a clear, transparent path for reducing carbon emissions 80% 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 technologies that are economically viable, as well as supportive public policy.

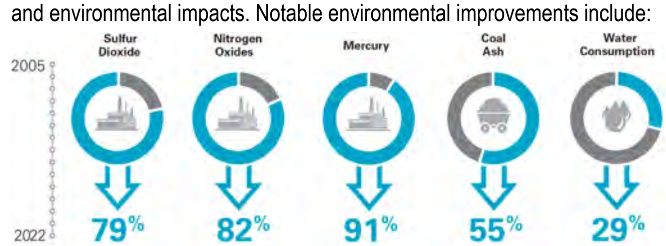
See Item 1A for risks and uncertainties related to strategic and sustainability goals and objectives.

Through 2022, we reduced carbon emissions from generation serving customers by an estimated 53% (from 2005 levels) and remain on track to achieve 80% carbon reduction by 2030.

Xcel Energy will be coal-free by year-end 2030, pending the approval of the proposed acceleration of the Tolk coal plant retirement to 2028. As we transition to clean energy, service reliability is a priority. Xcel Energy was ranked in the top quartile for customer reliability as determined in the 2022 Institute of Electrical and Electronics Engineers Annual Benchmarking Study.

Xcel Energy's wind capacity is now over 11,000 MW, including nearly 4,500 MW of owned wind. Our fleet continues to demonstrate high wind availability with 2022 performance at approximately 97%, while saving customers over $3 billion in fuel related costs and PTCs since 2017.In 2022, Minnesota and Colorado commissions approved resource plans that will add nearly 10,000 MW of utility-scale renewable energy to our systems.

Beyond carbon emissions, we have significantly reduced other emissions and environmental impacts. Notable environmental improvements include:



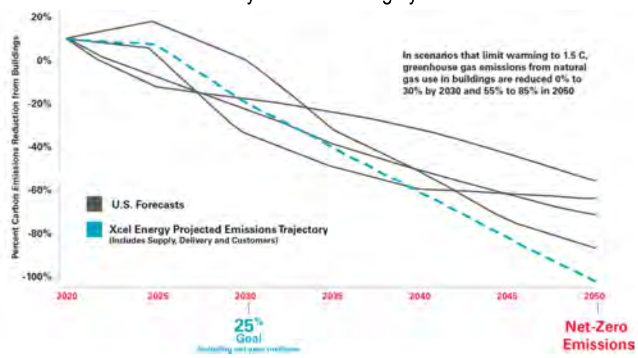
*Reductions in water consumption are from owned and purchased electricity that serves our customers. All other reductions are from owned generating plants.
**Coal ash and water consumption data are as of 2021.

As we prepare for early coal plant retirements, employees are provided advanced notice and offered retraining and relocation opportunities. To date, we have been successful in avoiding lay offs associated with our early coal plant retirements. We also help foster economic development opportunities to offset community economic impacts associated with coal plant closures. 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.

Significant transmission expansion will also be required to enable the clean energy transition, and Xcel Energy is already investing towards its goals. For example, our $2 billion Pathway project in Colorado will provide over 560 miles of transmission lines and enable nearly 5,500 MW of new renewable energy. In addition, as part of MISO's planned transmission expansion over the next decade, Xcel Energy has been awarded $1.2 billion of projects as part of Tranche 1.

Natural Gas Use in Buildings – Net Zero GHG by 2050

In 2021, we committed to reduce GHG emissions 25% by 2030 (from 2020 levels) and provide net-zero natural gas service by 2050 from the supply, distribution and end-use of natural gas. Similar to our electric plan, our vision to deliver gas service with net-zero emissions by 2050 aligns with science-based scenarios likely to limit warming by 1.5 C.



Our net-zero natural gas strategy includes:

- Working with suppliers to purchase only low emissions gas supply by 2030.
- Operating the cleanest possible system to achieve net-zero methane emissions on the system by 2030.
- Offering customer options that promote conservation, encourage electrification, where beneficial, and incorporate clean fuels such as hydrogen and renewable natural gas.
- Applying high quality carbon offsets through projects that remove emissions from other parts of the economy while providing additional environmental and social benefit.

Electrification of the Transportation Sector

In addition to transitioning our own generation fleet, we are helping to decarbonize other sectors, starting with transportation. We aim to enable one out of five vehicles in our service areas to be electric 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. By 2050, our vision is to run all vehicles in our service area with carbon-free electricity or other clean energy. We have launched new products and services across our service territories. In addition, we have an approved, transportation electrification plan in Colorado and comprehensive transportation plans in Minnesota and Wisconsin that are pending commission approval.

Innovation and Policy

Passage of the IRA is expected to reduce the cost of renewables for our customers, improve the competitiveness of our renewable projects and improve liquidity and credit metrics. The IRA is expected to reduce the cost of future wind projects by 50-60% and solar projects by 25-40% (levelized cost of energy basis). The IRA also lowers the costs of hydrogen production that could be used for generation and the natural gas system. Finally, the IRA is likely to provide customers additional benefits from PTCs for the generation of electricity from our nuclear fleet.

New and emerging technologies are foundational to fulfilling our strategic priorities. Advancement of economical, resilient and reliable zero-carbon 24/7 power technologies, as well as advanced storage and new low-carbon fuels, are needed to deliver on our clean energy goals by 2050.

We actively monitor and participate in emerging and advanced energy technologies through collaborations with researchers, technology developers, venture investors and others in our industry. We have several initiatives, pilots and demonstration projects underway that are advancing and testing the real-world applications of cutting-edge technologies. Our recently announced partnership with Form Energy to develop two 10 MW, 100-hour energy storage pilot projects is an example.

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 load growth, renewable energy and distributed energy resources. We are in the process of installing smart meters, which will deliver numerous customer and operational benefits, providing near-real-time communication, allowing customers to know how much energy they are using and what it will cost them. Along with the smart meters, customers will have new digital tools to make it easier to access their energy information, gain useful insights to better understand and manage their energy use and make smarter energy choices that lower their bills.

KEEP BILLS LOW

Customer affordability is critical to successful strategy execution. From 2013 - 2022, we have kept residential electric bill growth to 1.8% per year and below the rate of inflation. Residential gas bills were near flat, growing 0.3% per year from 2013 - 2021. Global pressures on natural gas prices increased customer natural gas bills in 2022. We pass the cost of natural gas directly to customers (without markup) through fuel clauses in most of our states, and higher gas prices affected the affordability of the service we provide.

We have taken several steps to address this concern:

- Low-income customers are eligible to receive assistance with their bills. In 2022, we set a company record for energy assistance outreach as 193,000 customers were connected to programs that provided $216 million in funding.
- Xcel Energy has invested more than $2 billion over the past decade in a comprehensive suite of electric and natural gas conservation programs.
- We also kept O&M expenses flat from 2014 through 2021. While O&M increased in 2022 due to global inflation pressures and other drivers, our goal is to reduce 2023 O&M expenses 2% from 2022 levels and keep them relatively flat thereafter.
- We continue to invest to reduce operating costs through ongoing process and technology improvements, including the use of drone technologies, automated work processes, artificial intelligence and continuous improvement methodologies.
- In addition, we are augmenting our One Xcel Energy Way program in 2023, which we expect to drive increased productivity and efficiency across all levels of the Company.
- As previously discussed, 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 renewable energy while saving customers money.

REACHING OUR GOALS RESPONSIBLY

We instituted oversight of environmental performance by the Board of Directors beginning in 2000 and was among the first U.S. energy providers to tie carbon reduction to executive compensation over fifteen years ago.

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.

STRENGTHEN OUR COMMUNITIES

We provide a fundamental service, powering communities with safe, reliable, affordable and increasingly clean energy.

For our local communities, we initiated 40 economic development projects in 2022, which are projected to create over $1.8 billion in capital investments and 2,900 jobs. Additionally, nearly 60% of our supply chain spend was local and we spent approximately $550 million with diverse suppliers.

Our employees served on more than 520 nonprofit organization or local community boards in 2022. The Xcel Energy Foundation contributed $4.4 million to 426 nonprofit organizations that support its three charitable giving focus areas: STEM Career Pathways, Environmental Sustainability, and Community Vitality.

The Foundation, Company, employees and retirees also contributed more than $5 million to local communities through Xcel Energy's annual United Way Giving Campaign and nearly 3,000 volunteers participated in Xcel Energy's annual Day of Service, supporting more than 100 nonprofit projects.

VALUE PEOPLE AND OPERATE WITH INTEGRITY

Champion 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.

Cultivate a Diverse, Best-in-Class Workforce

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.

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.

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.

We partner with educational and community organizations to attract and hire diverse employees who reflect the communities we serve and live our values. Xcel Energy had 11,982 full-time employees and workforce demographics as of December 2022 were as follows:

	Female	Ethnically Diverse
Board of Directors	33 %	17 %
CEO direct reports	33	22
Management	25	12
Employees	24	18
New hires	35	24
Interns (hired throughout 2022)	32	25

To help foster a culture of inclusivity, we offer leaders and employees training on microinequities and unconscious bias. The Company hosts 12 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, 2022, approximately 42% of our employees (5,087) were covered by collective bargaining agreements.

Employee turnover for 2022 and future projected retirement eligibility:

Employee Turnover	
Bargaining	7 %
Non-Bargaining	15
Overall [(a)]	11

Retirement Eligibility	
Within next 5 years	24 %
Within next 10 years	35

(a) 24% of turnover was due to retirements.

We have 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.

Annual Code of Conduct training is required for all employees and the Board of Directors.

We do not tolerate Code of Conduct 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.

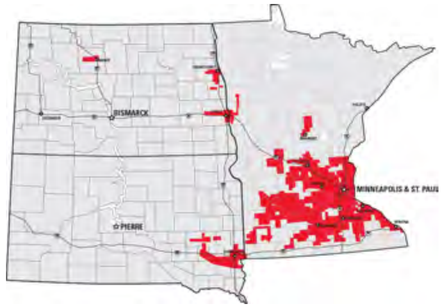
Xcel Energy received the following recognitions in 2022:

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

Utility Subsidiaries

NSP-Minnesota

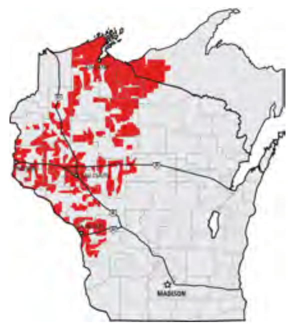
Electric customers	1.5 million
Natural gas customers	0.5 million
Total assets	$23.7 billion
Rate Base (estimated)	$15.1 billion
ROE (net income / average stockholder's equity)	8.76%
Electric generating capacity	8,949 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	33,000 miles
Electric distribution lines (conductor miles)	82,000 miles
Natural gas transmission lines	78 miles
Natural gas distribution lines	11,000 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

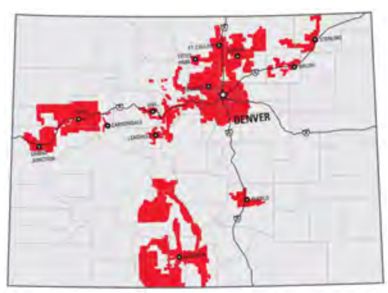
Electric customers	0.3 million
Natural gas customers	0.1 million
Total assets	$3.4 billion
Rate Base (estimated)	$2.1 billion
ROE (net income / average stockholder's equity)	10.57%
Electric generating capacity	548 MW
Gas storage capacity	4.3 Bcf
Electric transmission lines (conductor miles)	12,000 miles
Electric distribution lines (conductor miles)	28,000 miles
Natural gas transmission lines	3 miles
Natural gas distribution lines	3,000 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

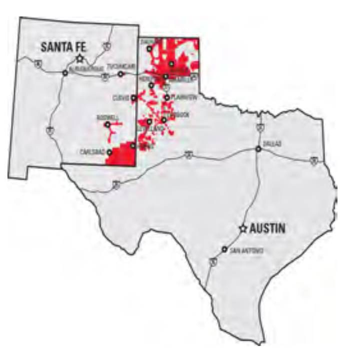
Electric customers	1.6 million
Natural gas customers	1.5 million
Total assets	$23.6 billion
Rate Base (estimated)	$14.9 billion
ROE (net income / average stockholder's equity)	8.23%
Electric generating capacity	6,151 MW
Gas storage capacity	32.1 Bcf
Electric transmission lines (conductor miles)	25,000 miles
Electric distribution lines (conductor miles)	79,000 miles
Natural gas transmission lines	2,000 miles
Natural gas distribution lines	24,000 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	$9.7 billion
Rate Base (estimated)	$6.7 billion
ROE (net income / average stockholder's equity)	9.36%
Electric generating capacity	5,249 MW
Electric transmission lines (conductor miles)	41,000 miles
Electric distribution lines (conductor miles)	24,000 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 116,885 (millions of KWh), 3.8 million customers and electric revenues of $12,123 million for 2022.

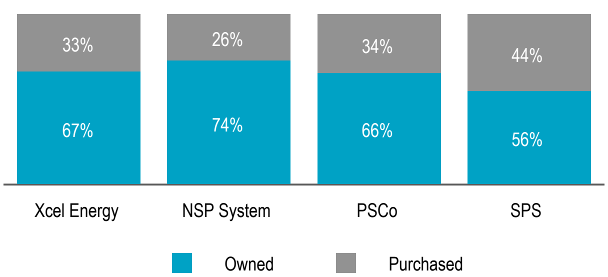
Electric Operations (percentage of total)	Sales Volume	Number of Customers	Revenues
Residential	23 %	86 %	29 %
C&I	55	12	48
Other	22	2	23

Retail Sales/Revenue Statistics [(a)]

	2022	2021
KWh sales per retail customer	24,285	23,968
Revenue per retail customer	$ 2,513	$ 2,405
Residential revenue per KWh	13.41 ¢	12.94 ¢
C&I revenue per KWh	9.02 ¢	8.73 ¢
Total retail revenue per KWh	10.35 ¢	10.03 ¢

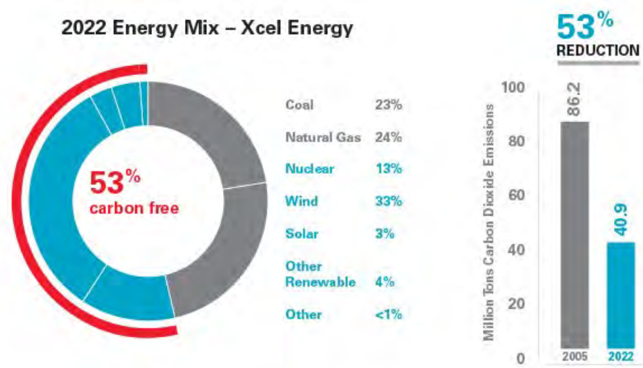
(a) See Note 6 to the consolidated financial statements for further information.

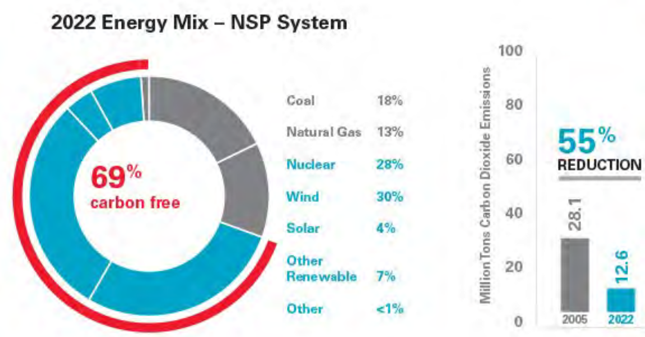
Owned and Purchased Energy Generation — 2022

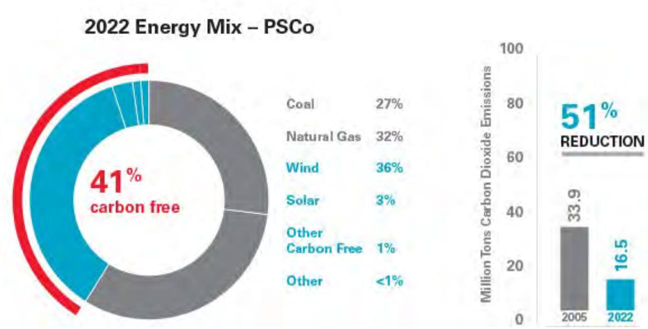


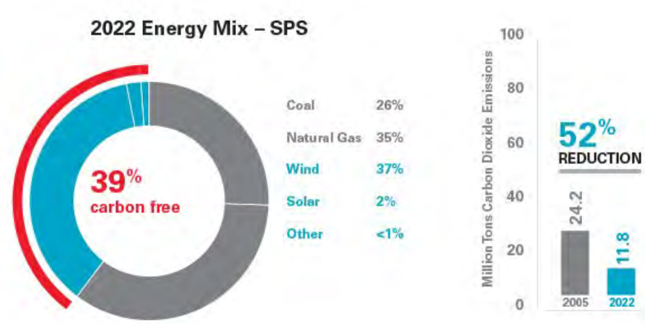
Electric Energy Sources

Total electric energy generation by source for the year ended Dec. 31:









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.

Wind

Owned — Owned and operated wind farms with corresponding capacity:

Utility Subsidiary	2022 Wind Farms	2022 Capacity (MW) [a]	2021 Wind Farms	2021 Capacity (MW) [b]
NSP System	16	2,352	14	2,031
PSCo	2	1,059	2	1,059
SPS	2	984	2	984
Total	20	4,395	18	4,074

(a) Summer 2022 net dependable capacity.
(b) Summer 2021 net dependable capacity.

PPAs — Number of PPAs with capacity range:

Utility Subsidiary	2022 PPAs	2022 Range (MW)	2021 PPAs	2021 Range (MW)
NSP System	129	1 — 206	128	1 — 206
PSCo	17	23 — 301	17	23 — 301
SPS	17	1 — 250	17	1 — 250

Capacity — Wind capacity (MW) for owned wind farms and PPAs:

Utility Subsidiary	2022	2021
NSP System	4,515	3,997
PSCo	4,082	4,085
SPS	2,548	2,548

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

Utility Subsidiary	2022	2021
NSP System	$ 18	$ 25
PSCo	11	17
SPS	13	17

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

Utility Subsidiary	2022	2021
NSP System	$ 37	$ 37
PSCo	38	35
SPS	27	27

Wind Development — Xcel Energy placed into service, repowered, or contracted for the following during 2022:

Project	Utility Subsidiary	Capacity (MW)
Dakota Range	NSP-Minnesota	298 (a)(b)
Nobles Repower	NSP-Minnesota	200 (a)(b)
Rock Aetna	NSP-Minnesota	20 (a)(b)
Various PPAs	Various	220 (c)

(a) Summer 2022 net dependable capacity.
(b) Values disclosed are the maximum generation levels. Capacity is attainable only when wind conditions are sufficiently available.
(c) Based on contracted capacity.

Xcel Energy currently has approximately 550 MW of owned wind under development or being repowered.

Project	Utility Subsidiary	Capacity (MW)	Estimated Completion
Northern Wind	NSP-Minnesota	100	2023 (a)
Grand Meadow Repower	NSP-Minnesota	100	2023
Border Winds Repower	NSP-Minnesota	150	2025
Pleasant Valley Repower	NSP-Minnesota	200	2025

(a) Placed in service in January 2023.

Solar

PPAs — Solar PPAs capacity by type:

Type	Utility Subsidiary	Capacity (MW)
Distributed Generation	NSP System	1,074
Utility-Scale	NSP System	269
Distributed Generation	PSCo	848
Utility-Scale	PSCo	732
Distributed Generation	SPS	20
Utility-Scale	SPS	192
Total		3,135

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

Utility Subsidiary	2022	2021
NSP System	$ 79	$ 90
PSCo	69	67
SPS	62	61

Solar Development — In September 2022, the MPUC approved NSP-Minnesota's proposal to add 460 MW of solar facilities at the Sherco site. The project is expected to cost approximately $690 million (two phases to be completed in 2024 and 2025). As a result of the IRA, the levelized cost of the project is expected to be approximately 30% lower than previously estimated.

PSCo placed approximately 200 MW of PPAs into service during 2022 and expects to place approximately 800 MW (including storage) of PPAs into service during 2023.

Nuclear

Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2022 net summer dependable capacity that serve 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 (nuclear, natural gas and coal):

Utility Subsidiary	Nuclear	
NSP System	Cost	Percent
2022	$ 0.76	51 %
2021	0.77	50

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 6,200 MW of total 2022 net summer dependable capacity, which provided 23% of Xcel Energy's energy mix in 2022.

Xcel Energy has plans to retire all of its existing coal generation by the end of 2030. Approved early coal plant retirements:

Year	Utility Subsidiary	Plant Unit	Capacity (MW)
2023	NSP-Minnesota	Sherco 2	682
2024	SPS	Harrington [(a)]	1,018
2025	PSCo	Comanche 2	335
2025	PSCo	Craig 1	42 [(b)]
2025	PSCo	Pawnee [(c)]	505
2026	NSP-Minnesota	Sherco 1	680
2027	PSCo	Hayden 2	98 [(b)]
2028	PSCo	Hayden 1	135 [(b)]
2028	PSCo	Craig 2	40 [(b)]
2028	NSP-Minnesota	A.S. King	511
2030	NSP-Minnesota	Sherco 3	517 [(b)]
2030	PSCo	Comanche 3	500 [(b)]
2034	SPS	Tolk 1 [(d)]	532
2034	SPS	Tolk 2 [(d)]	535

(a) Reflects expected conversion from coal to natural gas following the TCEQ order that Harrington cease use of coal fuel by Jan. 1, 2025.
(b) Based on Xcel Energy's ownership interest.
(c) Reflects conversion from coal to natural gas.
(d) Tolk Unit 1 and 2 are approved to be retired early in 2034. SPS proposed to retire both units in 2028 in the pending New Mexico and Texas rate cases.

Coal Fuel Cost — Delivered cost per MMBtu of coal consumed for owned electric generation and the percentage of fuel requirements (nuclear, natural gas and coal):

	Coal [(a)]	
Utility Subsidiary	Cost	Percent
NSP System		
2022	$ 2.27	37 %
2021	1.95	34
PSCo		
2022	1.48	55
2021	1.43	62
SPS		
2022	2.37	59
2021	2.07	66

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

Natural Gas

Xcel Energy has 23 natural gas plants with approximately 8,100 MW of total 2022 net summer dependable capacity, which provided 24% of Xcel Energy's mix in 2022.

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 (nuclear, natural gas and coal):

	Natural Gas	
Utility Subsidiary	Cost	Percent
NSP System		
2022	$ 7.58	12 %
2021 [(a)]	4.98	16
PSCo		
2022	7.09	45
2021 [(a)]	8.38	38
SPS		
2022	5.87	41
2021 [(a)]	6.72	34

(a) Reflective of Winter Storm Uri.

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

	System Peak Demand (MW)			
	2022		2021	
NSP System	9,245	June 20	8,837	June 9
PSCo	6,821	Sept. 6	6,958	July 28
SPS	4,280	July 19	4,054	Aug. 9

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 approximately 110,000 conductor miles of transmission lines, serving 22,000 MW of customer load, across its service territory.

Between 2023 and 2028, Xcel Energy plans to build approximately 1,700 additional conductor miles of transmission lines, primarily as part of the MISO Tranche 1 and Colorado Power Pathway projects.

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. Xcel Energy plans to invest approximately $1.7 billion implementing new network infrastructure, smart meters, advanced software, equipment sensors and related data analytics capabilities. As of Dec. 31, 2022, Xcel Energy had spent approximately $765 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 400,741 (thousands of MMBtu), 2.1 million customers and natural gas revenues of $3,080 million for 2022.

Natural Gas (percentage of total)	Deliveries	Number of Customers	Revenues
Residential	38 %	92 %	59 %
C&I	24	8	32
Transportation and other	38	<1	9

Sales/Revenue Statistics [(a)]

	2022	2021
MMBtu sales per retail customer	116	114
Revenue per retail customer	$ 1,318	$ 917
Residential revenue per MMBtu	11.97	8.61
C&I revenue per MMBtu	10.45	7.20
Transportation and other revenue per MMBtu	1.16	1.20

(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:

	2022		2021	
Utility Subsidiary	MMBtu	Date	MMBtu	Date [(a)]
NSP-Minnesota	867,385	Feb. 12	899,133	Feb. 11
NSP-Wisconsin	187,961	Jan. 6	167,656	Feb. 11
PSCo	2,243,552	Dec. 22	2,316,283	Feb. 14

(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 increases flexibility, decreases 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	2022	2021 [(a)]
NSP-Minnesota	$ 7.00	$ 7.48
NSP-Wisconsin	6.68	7.11
PSCo	6.33	6.06

(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 or commodity 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. No municipalization activities are occurring presently.

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 to 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 historic and current operating sites and other waste treatment, storage and disposal sites.

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.

Emerging Environmental Regulation

Clean Air Act — In April 2022, the EPA proposed regulations under the "Good Neighbor" provisions of the Clean Air Act. The proposed rules apply to Minnesota, Texas and Wisconsin. The proposal establishes an allowance trading program for NOx, potentially impacting Xcel Energy fossil fuel generating facilities. Under the proposed rule, facilities without NOx controls will have to secure additional allowances, install NOx controls, or develop a strategy of operations that utilizes the existing allowance allocations. The EPA has indicated that it intends for the rule to be final and applicable in the first half of 2023. While the financial impacts of the proposed regulation are uncertain and dependent on market forces, Xcel Energy anticipates that costs will be approximately $60 million annually and will be recoverable through regulatory mechanisms based on prior state commission practices.

In a June 2022 ruling, the United States Supreme Court held that an economy-wide approach to reducing greenhouse gas emissions from coal-fired power plants was not consistent with the Clean Air Act. Therefore, if the EPA proceeds with new rules, it cannot set a standard based on economy-wide generation shifting to other sources, such as renewable energy. It is anticipated that EPA will propose rules to limit GHG emissions from new and existing coal and natural gas-fired electric generating units in 2023. 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.

Coal Ash Regulation — In February 2023, the EPA entered into a Consent Decree, committing the agency to either issue new proposed rules by May 5, 2023, to regulate inactive CCR landfills under the CCR Rule for the first time, or to determine no such rules are necessary by that date. If proposed rules are issued in May, the EPA has committed to a May 2024 effective date for the new rules. Until proposed rules are issued, it is not certain what the impact will be on Xcel Energy, but we anticipate that additional inactive ash units could become regulated for the first time. It is also anticipated that the EPA may issue other CCR proposed rules in 2023 that further expand the scope of the CCR Rule.

Emerging Contaminants of Concern — PFAS are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. Xcel Energy does not manufacture PFAS but because PFAS are so ubiquitous in products and the environment, it may impact our operations. In September 2022, the EPA proposed to designate two types of PFAS as “hazardous substances” under the Comprehensive Environmental Response, Compensation, and Liability Act, specifically perfluorooctanoic acid and perfluorooctanesulfonic acid. This proposed rule could result in new obligations for investigation and cleanup wherever PFAS are found to be present. The impact the proposed regulation may have on electric and gas utilities is currently uncertain.

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 and depreciation of previously incurred capital expenditures for environmental improvements were approximately:

- $365 million in 2022.
- $365 million in 2021.
- $400 million in 2020.

Average annual expense of approximately $430 million from 2023 – 2027 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:

- $20 million in 2022.
- $60 million in 2021.
- $30 million in 2020.

Certain previously collected nuclear storage costs for the federal nuclear waste program are reimbursed to customers by the federal government as a result of a settlement we pursued regarding the government’s failure to deliver a disposal program. Installments received are reimbursed to customers as approved by the MPUC and other state regulators.

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.

Information about our Executive Officers [a]

Name	Age [b]	Current and Recent Positions	Time in Position
Robert C. Frenzel	52	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	56	Executive Vice President, Group President, Utilities, and Chief Customer Officer, Xcel Energy Inc.	March 2022 — Present
		Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 — March 2022
		Senior Vice President and Shared Services Executive, Bank of America, an institutional investment bank and financial services company	October 2015 — May 2018
Patricia Correa	49	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
Timothy O’Connor	63	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	60	Senior Vice President, Strategy, Security and External Affairs and Chief Sustainability Officer, Xcel Energy Inc.	March 2022 — Present
		Senior Vice President, Strategy, Planning and External Affairs, Xcel Energy Inc.	March 2020 — March 2022
		Vice President, Policy and Federal Affairs, Xcel Energy Services Inc.	January 2015 — March 2020
Amanda Rome	42	Executive Vice President, Chief Legal and Compliance Officer, Xcel Energy Inc.	June 2022 — Present
		Executive Vice President, General Counsel, Xcel Energy Inc.	June 2020 — June 2022
		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
Brian J. Van Abel	41	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, 2023.

(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.

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, safety 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 confirm these risks are well understood and given appropriate focus.

The Audit Committee is responsible for reviewing the adequacy of the committees' 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.

Emerging 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.

Risks Associated with Our Business

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 supplies.
- Impact of adverse weather conditions and natural disasters, including, tornadoes, icing events, floods and droughts.
- Performance below expected or contracted levels of output or efficiency.
- Availability of replacement equipment.
- Availability of adequate water resources and ability to satisfy water intake and discharge requirements.
- Availability or changes to wind patterns.
- 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 processes 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 require 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 operations and project plans for Xcel Energy and our customers. Such impacts could include timing of projects, including potential for project cancellation. Failure to adhere to project budgets and timelines adversely impacts 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.

A significant increase in fuel costs could cause a decline in customer demand, adverse regulatory outcomes and an increase in bad debt expense which may have a material impact on our results of operations. Despite existing fuel cost 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. Additionally, supply shortages may not be fully resolved, which negatively impacts 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 negatively impacts 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.

Public perception often does not distinguish between pass through commodity costs and base rates. High commodity prices that are being passed through to customer bills could impact our ability to recover costs for other improvements and operations.

Due to the 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, the Company cannot fully assure that its controls will be effective against all potential risks. 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.

The competition for talent has become increasingly prevalent, and we have experienced increased employee turnover due to the condition of the labor market. In addition, specialized knowledge and skills are required for many of our positions, 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 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 adversely impacts 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 and safety standards, progress payments, insurance requirements and security for performance. Poor vendor performance or contractor unavailability could impact ongoing operations, restoration operations, regulatory recovery, 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 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 earn 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 (including changes in recovery mechanisms) 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 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 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 our 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., MISO, SPP, Electric Reliability Council of Texas and California Independent System Operator), 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 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 prioritize 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 economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by recessionary factors, rising interest rates and 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.

Health epidemics continue to impact countries, communities, supply chains and markets. Uncertainty continues to exist regarding epidemics; the duration and magnitude of business restrictions including shutdowns (domestically and globally); the potential impact on the workforce including shortages of employees and third-party contractors due to quarantine policies, vaccination requirements or government restrictions; impacts on the transportation of goods, and the generalized impact on the economy.

We cannot ultimately predict whether an epidemic will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact on the health of our employees, our supply chain or our ability to recover higher costs associated with managing an outbreak.

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 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, 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. While we have business continuity plans in place, our ability to recover may be prolonged due to the type and extent of the event. 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 connect, restore and reliably serve our customers.

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

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, other countries and individuals. We 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 operations.

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 on 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.

While the Company maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damages experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events is evolving as the industry matures.

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

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. FERC can impose penalties of up to $1.5 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 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.

International commitments and agreements could result in future additional GHG reductions in the United States. In addition, in 2023 the EPA intends to publish draft regulations for GHG emissions from the power sector consistent with the agency's Clean Air Act authorities.

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 and 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.

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 establish strategies and expectations related to climate change and other environmental matters. Our ability to achieve any such strategies or expectations is subject to numerous factors and conditions, many of which are outside of our control. Examples of such factors include, but are not limited to, evolving legal, regulatory, and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets. Failures or delays (whether actual or perceived) in achieving our strategies or expectations related to climate change and other environmental matters could adversely affect our business, operations, and reputation, and increase risk of litigation.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms or extreme temperatures (high heating/cooling days) 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 and result in more frequent service interruptions. Periods of extreme temperatures could also impact our ability to meet demand.

More frequent and severe drought conditions, extreme swings in amount and timing of precipitation, changes in vegetation, unseasonably warm temperatures, very low humidity, stronger winds and other factors have increased the duration of the wildfire season and the potential impact of an event. Also, the expansion of the wildland urban interface increases the wildfire risk to surrounding communities and Xcel Energy's electric and natural gas infrastructure.

Other potential risks associated with wildfires include the inability to secure sufficient insurance coverage, or increased costs of insurance, regulatory recovery risk, and the potential for a credit downgrade and subsequent additional costs to access capital markets.

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, 2022	Fuel	Installed	MW [(a)]	
Steam:				
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511	
Sherco-Becker, MN				
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)
Dakota Range, SD, 72 Units	Wind	2022	298	(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, 133 Units [(e)]	Wind	2010	200	(d)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196	(d)
Rock Aetna - Murray County, MN, 8 Units	Wind	2022	20	(d)
		Total	8,949	

(a) Summer 2022 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Capacity is attainable only when wind conditions are sufficiently available.
(e) Repowered in 2022.

NSP-Wisconsin

Station, Location and Unit at Dec. 31, 2022	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, 62 Units	Hydro	Various	135	
		Total	548	

(a) Summer 2022 net dependable capacity.
(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit at Dec. 31, 2022	Fuel	Installed	MW [(a)]	
Steam:				
Comanche-Pueblo, CO				
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(b)
Craig-Craig, CO, 2 Units	Coal	1979 - 1980	82	(c)
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233	(d)
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	
Manchief, CO, 2 Units [(e)]	Natural Gas	2000	250	
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, 6 Units	Hydro	Various	23	
Wind:				
Rush Creek, CO, 300 units	Wind	2018	582	(f)
Cheyenne Ridge, CO, 229 units	Wind	2020	477	(f)
		Total	6,151	

(a) Summer 2022 net dependable capacity.
(b) Based on PSCo's ownership of 67%.
(c) Based on PSCo's ownership of 10%.
(d) Based on PSCo's ownership of 76% of Unit 1 and 37% of Unit 2.
(e) Purchased in 2022.
(f) Capacity is attainable only when wind conditions are sufficiently available.

SPS

Station, Location and Unit at Dec. 31, 2022	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	225
Harrington-Amarillo, TX, 3 Units	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, 3 Units	Natural Gas	1952 - 1964	298
Tolk-Muleshoe, TX, 2 Units	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 [(b)]
Sagamore-Dora, NM, 240 Units	Wind	2020	507 [(b)]
		Total	5,249

(a) Summer 2022 net dependable capacity.
(b) Capacity is attainable only when wind conditions are sufficiently available.

Electric utility overhead and underground transmission and distribution lines at Dec. 31, 2022:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Transmission				
500 KV	2,915	—	—	—
345 KV	12,183	2,457	5,418	11,676
230 KV	2,300	—	12,141	9,829
161 KV	626	1,795	—	—
138 KV	—	—	92	—
115 KV	8,033	1,829	5,011	14,905
Less than 115 KV	6,537	5,571	1,839	4,469
Total Transmission	32,594	11,652	24,501	40,879
Distribution				
Less than 115 KV	82,024	27,817	79,331	23,538
Total	**114,618**	**39,469**	**103,832**	**64,417**

Electric utility transmission and distribution substations at Dec. 31, 2022:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Substations	352	206	238	457

Natural gas utility mains at Dec. 31, 2022:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	78	3	2,067	20	11
Distribution	10,902	2,570	23,542	—	—

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.

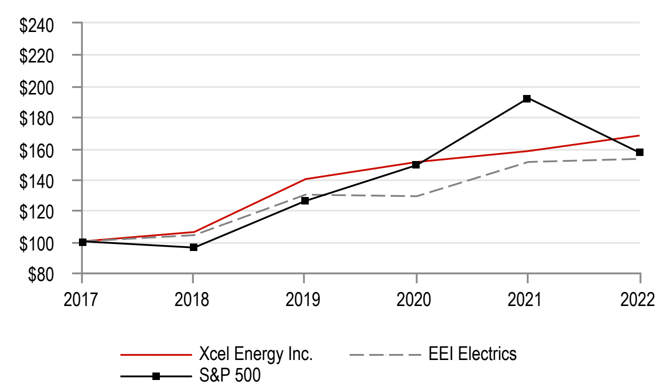
Stock Data

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. 16, 2023 was 47,359.

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, 2017 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, 2022, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6 — [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 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, 2022 and 2021, 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:

	2022	2021
Diluted Earnings (Loss) Per Share	**GAAP and Ongoing Diluted EPS**	**GAAP and Ongoing Diluted EPS**
PSCo	$ 1.33	$ 1.22
NSP-Minnesota	1.23	1.12
SPS	0.64	0.59
NSP-Wisconsin	0.23	0.20
Earnings from equity method investments — WYCO	0.04	0.05
Regulated utility [(a)]	3.47	3.18
Xcel Energy Inc. and Other	(0.29)	(0.22)
Total [(a)]	$ 3.17	$ 2.96

(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.

2022 Comparison with 2021

Xcel Energy — GAAP and ongoing earnings increased $0.21 per share for 2022. The increase was driven by regulatory outcomes, partially offset by higher depreciation, O&M expenses and interest charges. Costs for natural gas significantly increased in 2022 due to market conditions. However, fluctuations in electric and natural gas revenues associated with changes in fuel and purchased power and/or natural gas sold and transported generally do not significantly impact earnings (changes in revenues are offset by the related variation in costs).

PSCo — Earnings increased $0.11 per share for 2022, driven by regulatory outcomes and favorable weather. Higher revenues were partially offset by higher depreciation, O&M expenses and interest charges.

NSP-Minnesota — Earnings increased $0.11 per share for 2022 compared to 2021, driven by regulatory rate outcomes, partially offset by additional depreciation and O&M expenses.

SPS — Earnings increased $0.05 per share for 2022, largely related to regulatory rate outcomes, strong sales growth and favorable weather, partially offset by higher depreciation and O&M expenses.

NSP-Wisconsin — Earnings increased $0.03 per share for 2022 compared to 2021. The increase is due to regulatory rate outcomes and sales growth, partially offset by higher depreciation and O&M expenses.

Xcel Energy Inc. and Other — Earnings decreased $0.07 per share year-to-date due to higher interest charges and decreased earnings from EIP investments.

Changes in Diluted EPS

Components significantly contributing to changes in EPS:

2022 vs. 2021		
Diluted Earnings (Loss) Per Share		**Dec. 31**
GAAP and ongoing diluted EPS — 2021	**$**	**2.96**
Components of change — 2022 vs. 2021		
Higher electric revenues, net of electric fuel and purchased power		0.89
Higher natural gas revenues, net of cost of natural gas sold and transported		0.16
Lower ETR [(a)]		0.15
Higher depreciation and amortization		(0.40)
Higher O&M expenses		(0.24)
Higher interest expense		(0.15)
Higher taxes (other than income taxes)		(0.08)
Other (net)		(0.12)
GAAP and ongoing diluted EPS — 2022	**$**	**3.17**

(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:

	2022	2021
ROE	**GAAP and Ongoing ROE**	**GAAP and Ongoing ROE**
PSCo	8.23 %	8.23 %
NSP-Minnesota	8.76	8.45
SPS	9.36	9.22
NSP-Wisconsin	10.57	9.92
Operating Companies	8.74	8.58
Xcel Energy	10.76	10.58

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

	2022 vs. Normal	2021 vs. Normal	2022 vs. 2021
HDD	6.5 %	(6.6)%	13.0 %
CDD	23.7	12.2	16.1
THI	5.6	26.8	(15.8)

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

	2022 vs. Normal	2021 vs. Normal	2022 vs. 2021
Retail electric	$ 0.138	$ 0.096	$ 0.042
Decoupling and sales true-up	(0.061)	(0.066)	0.005
Electric total	$ 0.077	$ 0.030	$ 0.047
Firm natural gas	0.037	(0.025)	0.062
Total	$ 0.114	$ 0.005	$ 0.109

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

	2022 vs. 2021				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Actual					
Electric residential	(1.5)%	(1.2)%	6.5 %	1.1 %	(0.1)%
Electric C&I	—	1.7	8.9	3.3	3.3
Total retail electric sales	(0.5)	0.8	8.4	2.6	2.3
Firm natural gas sales	5.4	18.3	N/A	17.3	10.1

	2022 vs. 2021				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Weather-normalized					
Electric residential	(3.6)%	(0.2)%	0.8 %	— %	(1.3)%
Electric C&I	(0.3)	2.1	8.4	3.4	3.2
Total retail electric sales	(1.4)	1.3	6.9	2.4	1.8
Firm natural gas sales	(3.1)	5.5	N/A	5.8	0.1

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

- PSCo — Residential sales declined due to decreased use per customer, partially offset by a 1.1% increase in customers. C&I sales decline was attributable to decreased use per customer, primarily in the manufacturing sector (largely due to an alternative generation arrangement with a significant customer), partially offset by strong small C&I sales in the food services and health care sectors.
- NSP-Minnesota — Residential sales decline reflects a decreased use per customer, partially offset by a 1.1% increase in customers. Growth in C&I sales was primarily due to higher use per customer, particularly in the manufacturing, real estate and leasing, and food service sectors.
- SPS — Residential sales growth was primarily attributable to a 0.9% increase in customers, partially offset by lower use per customer. C&I sales increased due to higher use per customer, primarily driven by the energy sector.
- NSP-Wisconsin — C&I sales growth was associated with higher use per customer, experienced primarily in the transportation and manufacturing sectors.

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

- Natural gas sales reflect growth in NSP-Minnesota and NSP-Wisconsin attributable primarily to increased residential use per customer and customer growth as well as increases in C&I sales due to higher use per customer. These increases were offset by a reduction in PSCo natural gas sales, primarily driven by declines in residential 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. 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)	2022	2021
Electric revenues	$ 12,123	$ 11,205
Electric fuel and purchased power	(5,005)	(4,733)
Electric margin	$ 7,118	$ 6,472

Change in Electric Margin

(Millions of Dollars)	2022 vs. 2021
Regulatory rate outcomes (Minnesota, Colorado, Texas, New Mexico and Wisconsin)	$ 506
Revenue recognition for the Texas rate case surcharge [(a)]	85
Sales and demand [(b)]	80
Non-fuel riders	64
Wholesale transmission (net)	50
Estimated impact of weather (net of decoupling/sales true-up)	33
PTCs flowed back to customers (offset by lower ETR)	(150)
Other (net)	(22)
Total increase	$ 646

(a) Recognition of revenue from the Texas rate case outcome is largely offset by recognition of previously deferred costs.

(b) Sales excludes weather impact, net of decoupling in Colorado and proposed sales true-up mechanism in Minnesota.

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)	2022	2021
Natural gas revenues	$ 3,080	$ 2,132
Cost of natural gas sold and transported	(1,910)	(1,081)
Natural gas margin	$ 1,170	$ 1,051

Change in Natural Gas Margin

(Millions of Dollars)	2022 vs. 2021
Regulatory rate outcomes (Minnesota, Colorado, Wisconsin, North Dakota)	$ 61
Estimated impact of weather	46
Conservation revenue (offset in expenses)	13
Infrastructure and integrity riders	9
Winter Storm Uri disallowances	(20)
Other (net)	10
Total increase	$ 119

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $170 million year-to-date, due to the following approximately equal drivers: inflation and impacts of supply chain constraints; operational activities (vegetation management, repairs/maintenance and storms); costs for technology and customer programs; insurance-related costs; recognition of previously deferred amounts related to the 2021 Texas rate case; and other.

Depreciation and Amortization — Depreciation and amortization increased $292 million year-to-date. The increase was primarily driven by capital investment, recognition of previously deferred costs related to the Texas Electric Rate Case and several wind farms going into service.

Other Income (Expense) — Other income (expense) decreased $18 million year-to-date, largely related to rabbi trust performance, which is primarily offset in O&M expenses (employee benefit costs).

Earnings from Equity Method Investments — Earnings from equity method investments decreased $26 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.

Interest Charges — Interest charges increased $111 million year-to-date. The increase was largely due to higher long-term debt levels to fund capital investments and higher interest rates.

Income Taxes — Income tax benefit increased $65 million year-to-date. The year-to-date increase was primarily driven by an increase in wind PTCs due to greater production at existing wind farms, several new wind farms going into service and an increase in the PTC rate partially offset by higher pretax earnings.

Xcel Energy Inc. and Other Results

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

	Contribution (Millions of Dollars)	
	2022	2021
Xcel Energy Inc. financing costs	$ (153)	$ (129)
Venture Holdings [(a)]	5	21
Xcel Energy Inc. taxes and other results	(12)	(12)
Total Xcel Energy Inc. and other costs	$ (160)	$ (120)

	Contribution (Diluted Earnings (Loss) Per Share)	
	2022	2021
Xcel Energy Inc. financing costs	$ (0.28)	$ (0.24)
Venture Holdings [(a)]	0.01	0.04
Xcel Energy Inc. taxes and other results	(0.02)	(0.02)
Total Xcel Energy Inc. and other costs	$ (0.29)	$ (0.22)

(a) 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.

2021 Comparison with 2020

A discussion of changes in Xcel Energy's results of operations, cash flows and liquidity and capital resources from the year ended Dec. 31, 2020 to Dec. 31, 2021 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 2021, which was filed with the SEC on Feb. 23, 2022. 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 and credit quality.

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.
NDPSC	Retail rates, services and other aspects of electric and natural gas operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. 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.
SDPUC	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.
Transmission Cost Recovery	Recovers costs for investments in Minnesota, North Dakota, and South Dakota for electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation in South Dakota.
FCA	Recovers prudently incurred costs of fuel related items and purchased energy (Minnesota, North Dakota and South Dakota).
Purchased Gas Adjustment	Provides for prospective monthly rate adjustments in Minnesota and North Dakota 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. The statute authorizing the GUIC Rider is set to expire June 30, 2023.
Sales True-up	NSP-Minnesota has historically had a sales true-up mechanism for all electric customer classes which 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.

(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.

Pending and Recently Concluded Regulatory Proceedings

2022 Minnesota Electric Rate Case — In October 2021, NSP-Minnesota filed a three-year electric rate case with the MPUC. The request is based on a ROE of 10.2%, a 52.5% equity ratio and forward test years.

In December 2021, the MPUC approved interim rates, subject to refund, of $247 million, effective Jan. 1, 2022. In November 2022, NSP-Minnesota revised its rate request to $498 million over three years.

The revised request is detailed as follows:

(Amounts in Millions)	2022	2023	2024	Total
Rate request (annual increase)	$ 234	$ 94	$ 170	$ 498
Rate base	10,923	11,425	11,902	N/A

In 2022, several parties filed testimony with various recommendations. The DOC provided the following recommendations in surrebuttal testimony.

	2022	2023	2024
NSP-Minnesota's filed base revenue request	$ 396	$ 546	$ 677
Recommended adjustments:			
Rate base and rate of return	(72)	(65)	(65)
MISO capacity credits	(66)	(112)	(111)
Sales forecast update	(51)	—	—
Monticello and wind farm life extension	(21)	(54)	(51)
PTC forecast	(28)	(1)	(1)
Property tax	(14)	(23)	(34)
Prepaid pension asset and liability	(13)	(21)	(32)
O&M expenses	(37)	(39)	(44)
Sherco 3 and King remaining life	—	29	28
Other, net	(23)	(33)	(43)
Total adjustments	(325)	(319)	(353)
Total proposed revenue change	$ 71	$ 227	$ 324

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

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

2022 Minnesota Natural Gas Rate Case — In November 2021, NSP-Minnesota filed a request with the MPUC for a natural gas rate increase of $36 million, or 6.6%. The filing is based on a 2022 forecast test year and includes a requested ROE of 10.5%, an equity ratio of 52.5% and a rate base of $934 million. In December 2021, the MPUC approved an interim rate increase of $25 million, subject to refund, effective Jan. 1, 2022.

In October 2022, NSP-Minnesota and various parties filed an uncontested settlement, which includes the following key terms:

- Base rate revenue increase of $21 million, with a true up to weather normalized actual sales for 2022.
- Revenue decoupling mechanism.
- Symmetrical property tax true-up.
- ROE of 9.57%.
- Equity ratio of 52.5%.

In December 2022, the ALJ recommended MPUC approval of the settlement. A MPUC decision is expected in the first half of 2023.

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

In May 2022, NSP-Minnesota and NDPSC Staff reached a settlement, which reflects a rate increase of $5 million, based on a 9.8% ROE and 52.54% equity ratio. In October 2022, the NDPSC approved the settlement and final rates were implemented on Nov. 1, 2022.

South Dakota Electric Rate Case — In June 2022, NSP-Minnesota filed a South Dakota electric rate case seeking a revenue increase of approximately $44 million. The filing is based on a 2021 historic test year adjusted for certain known and measurable changes for 2022 and 2023, a ROE of 10.75%, rate base of approximately $947 million and an equity ratio of 53%. Interim rates were implemented on Jan. 1, 2023. Final rates are expected to be approved by the SDPUC in mid-2023.

Wind Repowering — In January 2021, the MPUC approved NSP-Minnesota's request for the repowering of 651 MW of owned wind projects. Two of the four repowering projects, where construction has not yet begun (in-service dates in 2025), now expect costs in excess of the original approval. While the capital costs have increased, the passage of the IRA and other changes result in a levelized cost of energy that is approximately 30% lower than the original approval.

In October 2022, NSP-Minnesota filed a request with the MPUC seeking approval of the higher capital costs for these repowering projects. In February 2023, the DOC filed comments recommending approval of recovery of the increased costs of these projects through the RES Rider. A final decision is pending.

2022 Upper Midwest RFP — In August 2022, NSP-Minnesota launched a RFP for 900 MW of solar or solar-plus-storage hybrid resources to come online by the end of 2025, including up to 300 MW of capacity to reuse the Sherco Unit 2 interconnection rights when the coal facility retires at the end of 2023.

NSP-Minnesota completed its bid evaluation process in December 2022 and will file for approval of the selected projects in early 2023.

2022 Minnesota Electric Vehicle Proposal — In August 2022, NSP-Minnesota filed a request with the MPUC for approval of approximately $320 million of capital investments (2022 through 2026) to support a public charging network, electric school bus pilot, and other expansions and modifications to its residential and commercial electric vehicle programs.

In October 2022, the MPUC referred the matter to the Office of Administrative Hearings to conduct a contested case on the proposals. In February 2023, other parties to the contested proceeding filed their direct testimony ranging in levels of support / opposition to the proposals. The evidentiary hearing is scheduled in Q2 2023 with a report from the ALJ expected in Q3 2023. A MPUC decision is expected in late 2023.

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 from Monticello and PI is disposed of 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 of 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.

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 to allow continued operation of the Monticello Plant until 2040.

A decision is expected in late 2023. 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.

In February 2023, NSP-Minnesota also filed an application with the NDPSC for an Advance Determination of Prudence for continued operation of the Monticello Plant until at least 2040. A decision is expected in 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 risk and to hedge sales and purchases.

NSP-Minnesota also engages in trading activity unrelated to these hedging activities. 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.
Michigan Public Service Commission	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.

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.

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. Reviews and approves Integrated Resource Plans for meeting future energy needs. Certifies the need and siting for generating plans greater than 50 MW. 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.

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.
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.
Pipeline system integrity adjustment	Recovers costs for transmission and distribution pipeline integrity management programs (rider ended on Dec. 31, 2022).
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, which reflects the transfer of $108 million previously recovered from customers through the pipeline system integrity adjustment rider. The request was based on a 10.25% ROE, an equity ratio of 55.66% and a 2022 current test year with a projected rate base of $3.6 billion.

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

In October 2022, the CPUC approved a rate increase net of rider roll-ins of $64 million. The decision reflects a stated WACC of 6.7%, a historic test year with a year-end rate base and $16 million of incremental depreciation expense. PSCo has the option to determine its ROE within a range of 9.2% to 9.5% and its equity ratio within a range of 52% to 55%, as long as it results in a WACC of 6.7%. The CPUC denied the 2023-2024 step increases. Base rates were placed in effect November 1, 2022.

Colorado Electric Rate Case — In November 2022, PSCo filed an electric rate case seeking a net increase of $262 million, or 8.2%. The total request reflects a $312 million increase, which includes $50 million of authorized costs currently recovered through various rider mechanisms. The request is based on a 10.25% ROE, an equity ratio of 55.7% and a 2023 forecast test year with a 2023 year-end rate base of $11.3 billion. PSCo requested rates effective in September 2023. A procedural schedule is expected to be established by the CPUC in the first quarter of 2023.

Colorado Resource Plan — In August 2022, the CPUC approved an updated settlement, which will result in the further acceleration of the retirement of the Comanche Unit 3 coal plant, an expected carbon reduction of at least 85% and an 80% renewable mix by 2030. The CPUC deferred a decision on the method of cost recovery for the retiring coal units to a separate docket, which will consider accelerated depreciation, creation of regulatory assets and securitization. PSCo filed the recovery method docket in the fourth 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 the Pawnee coal plant to natural gas by no later than Jan. 1, 2026.
- Early retirement of Comanche Unit 3 by Jan. 1, 2031 (was 2070) with reduced operations beginning in 2025.
- Addition of ~2,400 MW of wind.
- Addition of ~1,600 MW of universal-scale solar.
- Addition of 400 MW of storage.
- Addition of 1,300 MW of flexible, dispatchable generation.
- Addition of ~1,200 MW of distributed solar resources through our renewable energy programs.

In December 2022, the Company commenced the RFP process for generation resources with a bid receipt date of March 1, 2023. After reviewing the bids received, PSCo will file a report with the CPUC with recommended resource acquisitions and a CPUC decision on the resources to be acquired is expected in October 2023.

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

In October 2021, a settlement was reached on Winter Storm Uri costs and also addressed certain components of the 2020 decoupling refunds.

In April 2022, PSCo made its annual filing on this matter. In December 2022, the ALJ approved a settlement between PSCo, CPUC Staff and the UCA. The settlement requires PSCo to file a petition for declaratory judgment to address the treatment of any expired balance under the 3% soft cap provisions.

As of Dec. 31, 2022, PSCo has recognized a refund for Residential customers and a surcharge for small C&I customers based on 2020, 2021 and 2022 results.

Transmission Cost Adjustment — In December 2022, the CPUC suspended PSCo's request for 2023 TCA rate changes. The CPUC Staff protested the TCA on the grounds that only projects resulting in new transmission should be included and no repair or replacement of existing infrastructure should be included. The CPUC consolidated the matter with the pending electric rate case for assessment.

ECA Fuel Recovery — In December 2022, PSCo filed its first quarter 2023 ECA Advice Letter, which sought to recover $123 million of under-recovered 2022 fuel costs over two quarters (instead of the typical one). In December 2022, the CPUC found that the $123 million should be removed from the proposed ECA rates and required PSCo to file a separate application to recover these fuel costs. Proposed ECA rates were updated to remove the 2022 under-recovered balance and were implemented on Jan. 1, 2023. In February 2023, PSCo submitted an interim ECA filing which included $70 million of the 2022 under-recovered costs. A filing for the remaining amount is anticipated in the first quarter of 2023.

GCA NOPR — In June 2021, the CPUC issued a NOPR addressing the recovery of costs through the GCA. The CPUC has reopened the GCA NOPR and proposed a 2-step process aimed at 1) considering near term process changes to the GCA and 2) a longer term process to evaluate potential performance incentive structures. In step 1, consensus proposed rule amendments to update the process and filing requirements for GCA and related filings have been submitted to the CPUC for consideration. PSCo worked with other utilities and stakeholders regarding consensus proposed rule amendments for step 2, including a provision that each LDC bring forward its own performance incentive mechanism in a future filing. In December 2022, the CPUC approved the consensus proposal.

In February 2023, the Governor of Colorado issued an open letter to the CPUC, utilities, and other stakeholders directing agencies to take additional steps to address energy costs. It is likely this request will result in the opening of additional dockets to further explore the GCA and other related mechanisms. Additionally, the Colorado Legislature announced the formation of a Joint Select Committee to investigate the source of rising utility rates and explore potential actions to prevent future price instability.

Natural Gas Planning NOPR — In October 2021, the CPUC issued a NOPR to implement recent state legislation requiring natural gas utilities to develop clean heat plans to meet state greenhouse gas emission reduction targets, as well as updated demand-side management criteria. Additionally, the proposed rules included new comprehensive natural gas infrastructure planning requirements and related Certificate of Public Convenience and Necessity application procedures, changes in natural gas line extension policy, and details on emission accounting related to clean heat plans. PSCo recommended changes to the proposed rules, which may be incorporated into the final rules issued in the first quarter of 2023.

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 risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to these hedging activities.

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. Reviews and approves Integrated Resource Plans for meeting future energy needs
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.
DOT	Pipeline safety compliance.

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.
Transmission Cost Recovery 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.
Electric Vehicle Rider	Recovers costs of the Transportation Electrification Plan in New Mexico.
Advanced Metering System Surcharge	Recovers costs incurred in deployment of the Advanced Metering System in Texas.
Consulting Fee Rider	Recovers consulting fees and carrying charges incurred by SPS on behalf of the PUCT.

Pending and Recently Concluded Regulatory Proceedings

2021 Texas Electric Rate Case — In May 2022, the PUCT approved a settlement between SPS and intervening parties.

In July 2022, SPS filed to surcharge the final under-recovered amount, estimated to be approximately $85 million, substantially offset by the recognition of previously deferred costs.

(Millions of Dollars)	Year Ended Dec. 31, 2022
Revenue surcharge accrual	$ 85
Depreciation and amortization	(43)
O&M expenses	(16)
Interest expense	(12)
Taxes other than income taxes	(10)
Fuel and purchased power	(2)

2022 New Mexico Electric Rate Case — In November 2022, SPS filed an electric rate case with NMPRC seeking a revenue increase of $78 million, or 10%. The request is based on a future test year ending June 30, 2024, a ROE of 10.75%, an equity ratio of 54.7% and rate base of $2.4 billion. Additionally, the request reflects further acceleration of the Tolk coal plant depreciation life from 2032 to 2028.

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

- Staff and intervenor testimony: March 31, 2023.
- Rebuttal testimony: April 25, 2023.
- Stipulation: May 8, 2023.
- Hearing: June 5, 2023.
- End of rate suspension: Sept. 19, 2023.

2023 Texas Electric Rate Case — On Feb. 8, 2023, SPS filed an electric rate case with the PUCT seeking an increase in base rate revenue of $149 million. The impact to overall customer bills is expected to be approximately 13%. The request is based on a historical test year period ended Sept. 30, 2022, with an Update Period ended Dec. 31, 2022, a ROE of 10.65%, an equity ratio of 54.6% and retail rate base of $3.6 billion. Additionally, the request reflects further acceleration of the Tolk coal plant depreciation life from 2034 to 2028.

SPS is requesting a surcharge from July 13, 2023 through the effective date of new base rates. A PUCT decision is expected in the first quarter of 2024.

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

2022 All-Source RFP — In 2022, SPS issued an RFP, which seeks up to 947 MW of new or existing capacity resources to provide replacement capacity for retiring units and meet SPS' growing capacity needs through 2027. SPS will receive bids in the first quarter of 2023 and file for the approval of successful proposals in the second quarter of 2023.

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, DOT 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 risk and to hedge sales and purchases. Sharing of any margin is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement.

Other

Supply Chain

Xcel Energy's ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Manufacturing processes have experienced disruptions related to scarcity of certain raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, labor shortages and the impact of international conflicts/issues. Xcel Energy continues to monitor the situation as it remains fluid and seeks to mitigate the impacts by securing alternative suppliers, modifying design standards, and adjusting the timing of work.

Electric Distribution and Transmission Transformers

The availability of certain transformers is an industry-wide issue that has been significantly impacted and in some cases may result in delays in projects and new customer connections. Xcel Energy continues to seek alternative suppliers and prioritize work plans to mitigate impacts of supply constraints.

Solar Resources

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

An interim stay on tariffs has been issued and many significant solar projects have resumed with modified costs and projected in-service dates, including the Sherco Solar facility in Minnesota and certain PPAs in PSCo. Further policy action or other restrictions on solar imports (i.e., as a result of implementation of the Uyghur Forced Labor Protection Act) could impact project timelines and costs.

Marshall Wildfire

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

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

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

MISO Capacity Credits

The NSP System offered 1,500 MW of excess capacity into the MISO planning resource auction for June 2022 through May 2023. Due to a projected overall capacity shortfall in the MISO region, the 1,500 MWs offered cleared the auction at maximum pricing, generating revenues of approximately $90 million in 2022, with approximately $60 million expected in 2023. These amounts will primarily be used to mitigate customer rate increases or returned through earnings sharing or other mechanisms.

Inflation Reduction Act

In August 2022, the IRA was signed into law.

Key provisions impacting Xcel Energy include:

- Extends current PTC and ITC for renewable technologies (e.g., wind and solar).
- Restores full value of the PTC and ITC for qualifying facilities placed in-service after 2021.
- Creates a PTC for solar, clean hydrogen and nuclear.
- Establishes an ITC for energy storage, microgrids, interconnection facilities, etc.
- Allows companies to monetize or sell credits to unrelated parties.

Xcel Energy anticipates the IRA will materially reduce the cost of renewable energy, resulting in significant customer savings.

The IRA is expected to allow Xcel Energy to monetize tax credits more efficiently with the incremental benefits passed through to customers. Transferability provisions apply to eligible tax credits generated starting in 2023 for both new and existing facilities. Xcel Energy anticipates tax credit transferability from existing renewable projects will improve cash from operations by $1.8 billion (2023 - 2027), assuming constructive regulatory outcomes and the development of a market.

The IRA creates a nuclear PTC beginning in 2024 that may also provide additional customer savings. The annual customer benefit from these PTCs could range from $0 to $300 million, depending on locational marginal pricing, as well as constructive U.S. Treasury guidance regarding computation of the credits.

In addition, the IRA created a new corporate AMT. Xcel Energy does not anticipate AMT having a material cash impact based on current estimates and our interpretation of its application.

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).

Xcel Energy has received recovery approval from all of our impacted states except for Texas, which is pending. A summary of pending and recently approved regulatory requests for Winter Storm Uri cost recovery is listed below.

Utility Subsidiary	Jurisdiction	Regulatory Status
NSP-Minnesota	Minnesota	In 2021, the MPUC allowed recovery of $179 million of costs (with no financing charge) starting in September 2021, pending a prudency review. The C&I class ($82 million) will be recovered over 27 months and the residential class ($97 million) will be recovered over a 63-month recovery period. In August 2022, the MPUC approved recovery of Uri storm costs with a $19 million disallowance.
PSCo	Colorado	In May 2021, PSCo filed a request with the CPUC to recover $263 million in weather-related electric costs, $287 million in incremental natural gas costs and $4 million in incremental steam costs over 24 months with no financing charge. In July 2022, the CPUC approved a partial settlement providing full recovery of fuel costs, with the exception of an $8 million disallowance, over 24 months for electric and 30 months for natural gas customers.
SPS	Texas	In 2021, SPS filed to recover $88 million of Winter Storm Uri costs over 24 months, as part of the Texas fuel surcharge filing, with total under-recovered costs of $121 million. In April 2022, interim rates designed to recover $121 million over 30 months were approved, subject to PUCT approval through the triennial Fuel Reconciliation proceeding. In July 2022, the intervenors filed recommendations. The Texas Industrial Energy Consumers and PUCT staff recommended disallowances of approximately $10 million (off-system sales margins). The Office of Public Utility Counsel recommended disallowances of approximately $15 million (off-system sales margins and adjustment to energy loss factors). The Alliance of Xcel Municipalities recommended disallowances of approximately $100 million (natural gas storage, contracted capability and off-system sales margins). In November 2022, the ALJs found that costs were prudently incurred and recommended no disallowances. A final PUCT decision is anticipated in the first quarter of 2023.

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, 2022 and 2021, Xcel Energy had regulatory assets of $3.9 billion and $3.8 billion, respectively and regulatory liabilities of $6.0 billion and $5.7 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, 2022, 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, 2022, Xcel Energy set the rate of return on assets used to measure pension costs at 6.93%, which is 44 basis points higher than the rate set in 2021. The rate of return used to measure postretirement health care costs is 5.00% at Dec. 31, 2022, which is 90 basis points higher than the rate set in 2021. 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 and postretirement health care obligations at 5.80% at Dec. 31, 2022. This represents a 272 basis point and 271 basis point increase, respectively, from 2021. 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 Bank of America US 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 2022 pension costs:

	Pension Costs	
(Millions of Dollars)	+1%	-1%
Rate of return [(a)]	$ (11)	$ 26
Discount rate [(a)]	$ 1	$ 8

(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, 2022, the initial medical trend cost claim assumptions for Pre-65 was 6.5% and Post-65 was 5.5%. 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 2022 were $50 million and will remain relatively consistent in future years. Investment returns were less than the assumed levels in 2022, but exceeded the assumed levels in 2021 and 2020.

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 2022).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $66 million in 2023 and $58 million in 2024, while the actual pension costs were $114 million in 2022 and $121 million in 2021. The expected decrease in 2023 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 2020 - 2023:

- $50 million in January 2023.
- $50 million in 2022.
- $131 million in 2021.
- $150 million in 2020.

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 $13 million, $15 million and $11 million during 2022, 2021 and 2020, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $12 million during 2023. 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. Escrow accounting treatment was also approved for ongoing pension and other post-employment benefit expenses, including settlement charges.
- 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 is required to create a regulatory liability that adjusts the annual post-retirement benefits amount to zero in order to match the amount collected in rates.
- 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.

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 $2.2 billion in 2022 and $2.1 billion in 2021.

NSP-Minnesota obtains periodic independent cost studies 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 2022 - 2024 Nuclear Decommissioning Study and Assumptions were approved by the MPUC in August 2022. The MPUC ordered the next triennial decommissioning study be filed by December 1, 2024, allowing for four years between filings.

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 approved retirement dates which can be different than the expiration dates 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).

In April 2022, the Company received approval from the MPUC, in the Integrated Resource Plan, to pursue extending the operating life of the Monticello Nuclear Generating Plant by ten years from 2030 to 2040. This life extension is subject to NRC approval of Monticello's nuclear license extension request.

The retirement dates of the Prairie Island Unit 1 and Unit 2 remain unchanged, 2033 and 2034 respectively. The estimated timing of the decommissioning activities is based upon the DECON method, which assumes prompt removal and dismantlement. Decommissioning activities are expected to begin at the commission approved retirement date and be completed for both facilities by 2101.

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.

NSP-Minnesota 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, 2022.

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 for 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 on the contracts underlying our derivatives, the contracts expose us to credit and non-performance risk.

Distress in the financial markets may impact counterparty risk and the fair value of the securities in the nuclear decommissioning fund and pension fund.

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, 2022:

(Millions of Dollars)	Futures / Forwards Maturity Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [a]	$ (8)	$ (6)	$ (7)	$ (2)	$ (23)
NSP-Minnesota [b]	5	(4)	—	(3)	(2)
PSCo [a]	10	3	3	—	16
PSCo [b]	(56)	(15)	8	—	(63)
	$ (49)	$ (22)	$ 4	$ (5)	$ (72)

(Millions of Dollars)	Options Maturity Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [b]	$ —	$ —	$ —	$ 15	$ 15
PSCo [b]	40	7	—	—	47
	$ 40	$ 7	$ —	$ 15	$ 62

(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)	2022	2021
Fair value of commodity trading net contracts outstanding at Jan. 1	$ (33)	$ (54)
Contracts realized or settled during the period	(15)	(54)
Commodity trading contract additions and changes during the period	38	75
Fair value of commodity trading net contracts outstanding at Dec. 31	$ (10)	$ (33)

A 10% increase and 10% decrease in forward market prices for Xcel Energy's commodity trading contracts would have likewise increased and decreased pretax income from continuing operations, by approximately $8 million at Dec. 31, 2022 and $13 million at Dec. 31, 2021. 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 using an industry standard methodology known as VaR. VaR expresses the potential change in fair value of 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 purchases 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	Average	High	Low
2022	$ 2	$ 1	$ 5	$ —
2021	$ 1	$ 2	$ 52	$ 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 weather event, VaR was $1 million and returned to $1 million by Feb. 19, 2021.

Nuclear Fuel Supply — NSP-Minnesota has contracted for its 2023 and 2024 enriched nuclear material requirements, which are in various stages of processing in Canada, Europe, and the United States. NSP-Minnesota is scheduled to take delivery of approximately 26% of its average enriched nuclear material requirements from Russia through 2030. We are closely monitoring the evolving situation in Ukraine and its global impacts. NSP-Minnesota is in the process of entering into new contracts to reduce the risk of supply interruptions of nuclear material from Russia. NSP-Minnesota will take additional further action to reduce this risk as necessary.

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.

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $8 million and $11 million in 2022 and 2021, respectively.

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

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. Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

The value of pension and postretirement plan assets and benefit costs are impacted by changes in discount rates and expected return on plan assets. Xcel Energy's ongoing pension and postretirement investment strategy is based on plan-specific investment recommendations that seek to optimize potential investment risk and minimize interest rate risk associated with changes in the obligations as a plan's funded status increases over time. The impacts of fluctuations in interest rates on pension and postretirement costs are mitigated by pension cost calculation methodologies and regulatory mechanisms that minimize the earnings impacts of such changes.

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, 2022, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $56 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $47 million. 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 an decrease in credit exposure of $26 million.

Xcel Energy conducts credit reviews for all wholesale, trading and non-trading commodity 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

Derivative contracts, with the exception of those designated as normal purchases and normal sales, 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. 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 — 2021	$	2,189
Components of change — 2022 vs. 2021		
Higher net income		139
Non-cash transactions		257
Changes in working capital		(300)
Changes in net regulatory and other assets and liabilities		1,647
Cash provided by operating activities — 2022	$	3,932

Net cash provided by operating activities increased by $1,743 million for 2022 as compared to 2021. The increase was primarily due to the deferral of net natural gas, fuel and purchased energy costs incurred during Winter Storm Uri in the first quarter of 2021.

Investing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash used in investing activities — 2021	$	(4,287)
Components of change — 2022 vs. 2021		
Increased capital expenditures		(394)
Other investing activities		28
Cash used in investing activities — 2022	$	(4,653)

Net cash used in investing activities increased by $366 million for 2022 as compared to 2021. The increase in capital expenditures was largely due to continued system expansion.

Financing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31	
Cash provided by financing activities — 2021	$	2,135
Components of change — 2022 vs. 2021		
Lower debt issuances		(1,159)
Higher repayments of long-term debt		(184)
Lower proceeds from issuance of common stock		(44)
Higher dividends paid to shareholders		(77)
Other financing activities		(5)
Cash provided by financing activities — 2022	$	666

Net cash provided by financing activities decreased by $1,469 million for 2022 as compared to 2021. The decrease was primarily related to the amount/timing of debt issuances and repayments 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. Xcel Energy expects to have adequate amounts of cash from operating and 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, Xcel Energy 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.

Material Cash Requirements and Other Commitments

	Payments Due by Period (as of Dec. 31, 2022)				
(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	$ 39,750	$ 2,059	$ 3,492	$ 2,714	$ 31,485
Finance lease obligations	228	10	20	17	181
Operating leases obligations [(a)]	1,457	264	506	287	400
Unconditional purchase obligations [(b)]	5,129	1,899	1,475	921	834
Other long-term obligations, including current portion [(c)]	111	53	35	23	—
Other short-term obligations	436	436	—	—	—
Short-term debt	813	813	—	—	—
Total contractual cash obligations	$ 47,924	$ 5,534	$ 5,528	$ 3,962	$ 32,900

(a) Included in operating lease obligations are $231 million, $455 million, $251 million and $326 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	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2023 - 2027 Total**
PSCo	$ 1,940	$ 2,140	$ 2,440	$ 2,550	$ 1,980	$ 2,190	$ 11,300
NSP-Minnesota	1,980	2,000	2,400	2,530	2,200	2,580	11,710
SPS	610	710	780	720	770	900	3,880
NSP-Wisconsin	370	540	570	500	450	540	2,600
Other [(a)]	(10)	10	10	(30)	10	10	10
Total base capital expenditures	$ 4,890	$ 5,400	$ 6,200	$ 6,270	$ 5,410	$ 6,220	$ 29,500

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

	Actual	Base Capital Forecast (Millions of Dollars)					
By Function	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2023 - 2027 Total**
Electric distribution	$ 1,370	$ 1,610	$ 1,790	$ 1,680	$ 2,000	$ 2,450	$ 9,530
Electric transmission	960	1,280	1,650	1,890	1,690	1,900	8,410
Electric generation	720	710	910	900	560	650	3,730
Natural gas	730	740	730	760	650	680	3,560
Other	700	780	840	570	510	540	3,240
Renewables	410	280	280	470	—	—	1,030
Total base capital expenditures	$ 4,890	$ 5,400	$ 6,200	$ 6,270	$ 5,410	$ 6,220	$ 29,500

The base five-year capital forecast includes transmission expansion through the proposed Colorado Pathway (approximately $1.7 billion) and MISO Tranche 1 (approximately $1.2 billion) as well as the proposed 460 MW Sherco Solar Generating Unit 1 and 2 (approximately $600 million).

The base capital investment plan does not include any potential renewable generation assets approved in our Minnesota and Colorado resource plans or additional transmission capital needed to integrate new renewable generation additions in Colorado, beyond the Pathway project.

We expect further clarification in the second half of 2023 after the commissions rule on the recommended resource plan portfolios, which could result in incremental capital expenditures of approximately $2 to $4 billion (assuming 50% ownership of the renewable projects). Furthermore, the base capital investment plan does not include any potential generation assets associated with our 2022 SPS Request for Proposal, which seeks up to 947 MW of new or existing capacity resources.

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 2027 — 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 2023 through 2027:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from operations [(a)]	$ 20,540
New debt [(b)]	8,210
Equity through the DRIP and benefit program	425
Other equity	325
Base capital expenditures 2023 - 2027	$ 29,500
Maturing Debt	$ 3,800

(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 2023, Xcel Energy announced an increase in the annual dividend of 13 cents per share, which represents an increase of 6.7%.

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, 2022	Dec. 31, 2021
Fair value of pension assets	$ 2,685	$ 3,670
Projected pension obligation [(a)]	2,871	3,718
Funded status	$ (186)	$ (48)

(a) Excludes non-qualified plan of $11 million and $43 million at Dec. 31, 2022 and 2021, respectively.

Pension Assumptions	2022	2021
Discount rate	5.80 %	3.08 %
Expected long-term rate of return	6.93	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:

- $1.50 billion for Xcel Energy Inc.
- $700 million for PSCo.
- $700 million for NSP-Minnesota.
- $500 million for SPS.
- $150 million for NSP-Wisconsin.

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

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. 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. 22, 2023, 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.	$ 1,500	$ 328	$ 1,172	$ 6	$ 1,178
PSCo	700	123	577	5	582
NSP-Minnesota	700	186	514	6	520
SPS	500	91	409	2	411
NSP-Wisconsin	150	29	121	2	123
Total	$ 3,550	$ 757	$ 2,793	$ 21	$ 2,814

(a) Credit facilities expire in September 2027.

(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, 2022 and 2021, Xcel Energy had approximately 550 million shares and 544 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 2023 financing plans reflect the following:

(Millions of Dollars)	Security	Amount	Anticipated Timing
Xcel Energy Inc.	Senior Unsecured Bonds	$ 500	Third Quarter
PSCo	First Mortgage Bonds	700	Second Quarter
SPS	First Mortgage Bonds	100	Third Quarter
NSP-Minnesota	First Mortgage Bonds	750	Second Quarter
NSP-Wisconsin	First Mortgage Bonds	125	Second Quarter

Long-Term Borrowings, Equity Issuances and Other Financing Instruments — Xcel Energy also plans to issue approximately $85 million of equity annually through the DRIP and benefit programs during the five-year forecast time period.

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

Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2023 Earnings Guidance — Xcel Energy's 2023 GAAP and ongoing earnings guidance is a range of $3.30 to $3.40 per share.[a]

Key assumptions as compared with 2022 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 increase ~1%.
- Capital rider revenue is projected to increase $90 million to $100 million (net of PTCs).
- O&M expenses are projected to decline ~2%.
- Depreciation expense is projected to increase approximately $130 million to $140 million.
- Property taxes are projected to increase approximately $35 million to $45 million.
- Interest expense (net of AFUDC - debt) is projected to increase $100 million to $110 million.
- AFUDC - equity is projected to increase $0 million to $10 million.
- ETR is projected to be ~(5%) to (7%).

(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 2022 base of $3.15 per share, which represents the mid-point of the original 2022 guidance range of $3.10 to $3.20 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, 2022. 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, 2022, 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, 2023	Feb. 23, 2023

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, 2022 and 2021, 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, 2022, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, 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, 2023

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		
	2022	**2021**	**2020**
Operating revenues			
Electric	$ 12,123	$ 11,205	$ 9,802
Natural gas	3,080	2,132	1,636
Other	107	94	88
Total operating revenues	15,310	13,431	11,526
Operating expenses			
Electric fuel and purchased power	5,005	4,733	3,512
Cost of natural gas sold and transported	1,910	1,081	689
Cost of sales — other	44	38	37
Operating and maintenance expenses	2,491	2,321	2,324
Conservation and demand side management expenses	331	304	288
Depreciation and amortization	2,413	2,121	1,948
Taxes (other than income taxes)	688	630	612
Total operating expenses	12,882	11,228	9,410
Operating income	2,428	2,203	2,116
Other (expense) income, net	(13)	5	(6)
Earnings from equity method investments	36	62	40
Allowance for funds used during construction — equity	75	73	115
Interest charges and financing costs			
Interest charges — includes other financing costs of $31, $29 and $28, respectively	953	842	840
Allowance for funds used during construction — debt	(28)	(26)	(42)
Total interest charges and financing costs	925	816	798
Income before income taxes	1,601	1,527	1,467
Income tax benefit	(135)	(70)	(6)
Net income	$ 1,736	$ 1,597	$ 1,473
Weighted average common shares outstanding:			
Basic	547	539	527
Diluted	547	540	528
Earnings per average common share:			
Basic	$ 3.18	$ 2.96	$ 2.79
Diluted	3.17	2.96	2.79

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2022	2021	2020
Net income	$ 1,736	$ 1,597	$ 1,473
Other comprehensive income			
Pension and retiree medical benefits:			
Net pension and retiree medical gains (losses) arising during the period, net of tax of $1, $— and $(2), respectively	5	—	(5)
Reclassification of losses to net income, net of tax of $1, $3 and $3, respectively	4	8	10
Derivative instruments:			
Net fair value increase (decrease), net of tax of $6, $1 and $(3), respectively	16	4	(10)
Reclassification of losses to net income, net of tax of $2, $2 and $2, respectively	5	6	5
Total other comprehensive income	30	18	—
Total comprehensive income	$ 1,766	$ 1,615	$ 1,473

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2022	2021	2020
Operating activities			
Net income	$ 1,736	$ 1,597	$ 1,473
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	2,436	2,143	1,959
Nuclear fuel amortization	118	114	123
Deferred income taxes	(140)	(79)	(8)
Allowance for equity funds used during construction	(75)	(73)	(115)
Earnings from equity method investments	(36)	(62)	(40)
Dividends from equity method investments	37	42	42
Provision for bad debts	73	60	60
Share-based compensation expense	20	31	73
Changes in operating assets and liabilities:			
Accounts receivable	(429)	(164)	(154)
Accrued unbilled revenues	(243)	(149)	(3)
Inventories	(203)	(126)	(80)
Other current assets	(58)	(34)	(45)
Accounts payable	195	138	(33)
Net regulatory assets and liabilities	570	(973)	(144)
Other current liabilities	102	(1)	29
Pension and other employee benefit obligations	(49)	(135)	(125)
Other, net	(122)	(140)	(164)
Net cash provided by operating activities	3,932	2,189	2,848
Investing activities			
Capital/construction expenditures	(4,638)	(4,244)	(5,369)
Sale of MEC	—	—	684
Purchase of investment securities	(1,332)	(757)	(1,398)
Proceeds from the sale of investment securities	1,297	743	1,378
Other, net	20	(29)	(35)
Net cash used in investing activities	(4,653)	(4,287)	(4,740)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(192)	421	(11)
Proceeds from issuances of long-term debt	2,164	2,710	2,940
Repayments of long-term debt	(601)	(417)	(1,001)
Proceeds from issuance of common stock	322	366	727
Dividends paid	(1,012)	(935)	(856)
Other, net	(15)	(10)	(26)
Net cash provided by financing activities	666	2,135	1,773
Net change in cash and cash equivalents	(55)	37	(119)
Cash, cash equivalents and restricted cash at beginning of period	166	129	248
Cash, cash equivalents and restricted cash at end of period	$ 111	$ 166	$ 129
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (887)	$ (788)	$ (758)
Cash (paid) received for income taxes, net	(15)	(4)	12
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 626	$ 501	$ 400
Inventory transfers to property, plant and equipment	78	87	275
Operating lease right-of-use assets	141	8	369
Allowance for equity funds used during construction	75	73	115
Issuance of common stock for reinvested dividends and/or equity awards	57	60	67

See Notes to Consolidated Financial Statements

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

	Dec. 31 2022	Dec. 31 2021
Assets		
Current assets		
Cash and cash equivalents	$ 111	$ 166
Accounts receivable, net	1,373	1,018
Accrued unbilled revenues	1,105	862
Inventories	803	631
Regulatory assets	1,059	1,106
Derivative instruments	279	123
Prepaid taxes	54	44
Prepayments and other	360	289
Total current assets	5,144	4,239
Property, plant and equipment, net	48,253	45,457
Other assets		
Nuclear decommissioning fund and other investments	3,234	3,628
Regulatory assets	2,871	2,738
Derivative instruments	93	67
Operating lease right-of-use assets	1,204	1,291
Other	389	431
Total other assets	7,791	8,155
Total assets	$ 61,188	$ 57,851
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 1,151	$ 601
Short-term debt	813	1,005
Accounts payable	1,804	1,409
Regulatory liabilities	418	271
Taxes accrued	569	569
Accrued interest	217	209
Dividends payable	268	249
Derivative instruments	76	69
Operating lease liabilities	217	205
Other	545	459
Total current liabilities	6,078	5,046
Deferred credits and other liabilities		
Deferred income taxes	4,756	4,894
Deferred investment tax credits	48	53
Regulatory liabilities	5,569	5,405
Asset retirement obligations	3,380	3,151
Derivative instruments	113	105
Customer advances	181	196
Pension and employee benefit obligations	390	306
Operating lease liabilities	1,038	1,146
Other	147	158
Total deferred credits and other liabilities	15,622	15,414
Commitments and contingencies		
Capitalization		
Long-term debt	22,813	21,779
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 549,578,018 and 544,025,269 shares outstanding at Dec. 31, 2022 and Dec. 31, 2021, respectively	1,374	1,360
Additional paid in capital	8,155	7,803
Retained earnings	7,239	6,572
Accumulated other comprehensive loss	(93)	(123)
Total common stockholders' equity	16,675	15,612
Total liabilities and equity	$ 61,188	$ 57,851

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, 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
Repurchases 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 loss					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
Net income				1,736		1,736
Other comprehensive income					30	30
Dividends declared on common stock ($1.95 per share)				(1,066)		(1,066)
Issuances of common stock	5,552,749	14	345			359
Share-based compensation			7	(3)		4
Balance at Dec. 31, 2022	549,578,018	$ 1,374	$ 8,155	$ 7,239	$ (93)	$ 16,675

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 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:

Nonregulated Subsidiary	Purpose
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 Minnesota community solar gardens.

Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries:

Direct Subsidiary
Xcel Energy Wholesale Group Inc.
Xcel Energy Market Holdings Inc.
Xcel Energy Ventures Inc.
Xcel Energy Retail Holdings Inc.
Xcel Energy Communication Group, Inc.
Xcel Energy International Inc.
Xcel Energy Transmission Holding Company, LLC
Nicollet Holdings Company, LLC
Xcel Energy Nuclear Services Holdings, LLC
Xcel Energy Services Inc.

Xcel Energy 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. The equity method of accounting is used for its investments in EIP funds and WYCO.

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

The 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, 2022 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 — The 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 and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other information available. 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. 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. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities.

Rates are utilized 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, refundable to utility customers over the remaining life of the related assets.

Xcel Energy anticipates that a tax rate increase would predominantly 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 over the book depreciable lives of the related property. The requirement to defer and amortize these credits specifically applies to certain federal ITCs, as determined by tax regulations and Xcel Energy tax elections. For tax credits otherwise eligible to be recognized when earned, Xcel Energy considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

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. Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes.

Xcel Energy measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the 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.

Interest and penalties related to income taxes are reported 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.

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.

Depreciation expense is recorded 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 are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. 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 3.7% for 2022, 3.5% for 2021 and 3.4% for 2020.

See Note 3 for further information.

AROs — Xcel Energy records AROs as a liability for the fair value of an ARO to be recognized in the period incurred (if it can be reasonably estimated), with the offsetting/associated 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 typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts 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 normally performed at least every three years and submitted to the state commissions for approval. Due to other regulatory activity, the next decommissioning study has been deferred one year until 2024.

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 amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable 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 is performed. 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.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are 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, 2022 and 2021, the allowance for bad debts was $122 million and $106 million, respectively.

Inventory — Inventory is recorded at the lower of average cost or net realizable value and consisted of the following:

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
Inventories		
Materials and supplies	$ 330	$ 289
Fuel	201	182
Natural gas	272	160
Total inventories	$ 803	$ 631

Equity Method Investments — The equity method of accounting is used for certain investments including WYCO and EIP funds, which requires Xcel Energy's recognition of its share of these investees' results, 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.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate 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, quoted prices for similar contracts or internally prepared valuation models may be used 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 determine fair value for each security.

See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates, and utility commodity prices, 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.

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 they contain a derivative, and if so, whether they may be exempted from derivative accounting if designated as normal purchases or normal sales.

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 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 and 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.

Alternative Revenue — Certain rate rider mechanisms (including decoupling/sales true up and CIP/DSM programs) qualify as alternative revenue programs. These mechanisms arise from instances in which 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, 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.

Emissions Allowances — Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any 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, 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 on a net basis in electric operating revenues in the consolidated statements of income.

2. Accounting Pronouncements

As of Dec. 31, 2022, there was no material impact from the recent adoption of new accounting pronouncements, nor expected material impact from recently issued accounting pronouncements yet to be adopted, on Xcel Energy's consolidated financial statements.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
Property, plant and equipment, net		
Electric plant	$ 49,639	$ 48,680
Natural gas plant	8,514	7,758
Common and other property	2,970	2,602
Plant to be retired [(a)]	2,217	1,200
CWIP	2,124	1,969
Total property, plant and equipment	65,464	62,209
Less accumulated depreciation	(17,502)	(17,060)
Nuclear fuel	3,183	3,081
Less accumulated amortization	(2,892)	(2,773)
Property, plant and equipment, net	$ 48,253	$ 45,457

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

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2022:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
NSP-Minnesota			
Electric generation:			
Sherco Unit 3	$ 623	$ 468	59 %
Sherco common facilities	180	115	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	3	50
Huntley Wilmarth	49	1	50
CapX2020	818	124	51
Total NSP-Minnesota [(a)]	$ 1,686	$ 715	

(a) Projects additionally include $4 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	$ 20	37 %
CapX2020	166	34	80
Total NSP-Wisconsin [(a)]	$ 343	$ 54	

(a) Projects additionally include $1 million in CWIP.

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
PSCo			
Electric generation:			
Hayden Unit 1	$ 157	$ 99	76 %
Hayden Unit 2	151	81	37
Hayden common facilities	42	29	53
Craig Units 1 and 2	82	51	10
Craig common facilities	39	24	7
Comanche Unit 3	918	174	67
Comanche common facilities	28	3	82
Electric transmission:			
Transmission and other facilities	186	72	Various
Gas transmission:			
Rifle, CO to Avon, CO	25	9	60
Gas transmission compressor	8	2	50
Total PSCo [(a)]	$ 1,636	$ 544	

(a) Projects additionally include $10 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, 2022		Dec. 31, 2021 [(a)]	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	11	Various	$ 22	$ 1,069	$ 77	$ 944
Net AROs [(b)]	1, 12	Various	—	339	—	(112)
Deferred natural gas, electric, steam energy/fuel costs		One to five years	581	299	504	543
Recoverable deferred taxes on AFUDC		Plant lives	—	292	—	289
Excess deferred taxes — TCJA	7	Various	13	205	14	219
Depreciation differences		One to 12 years	17	193	16	173
Environmental remediation costs	1, 12	Various	20	92	14	92
Benson biomass PPA termination and asset purchase		Six years	10	45	10	55
PI extended power uprate		12 years	4	42	4	46
Conservation programs [(c)]	1	One to two years	16	36	21	35
Purchased power contract costs		Term of related contract	10	36	9	45
State commission adjustments		Plant lives	1	33	1	32
Losses on reacquired debt		Term of related debt	3	32	3	35
Contract valuation adjustments [(d)]	1, 10	Term of related contract	28	28	22	34
Grid modernization costs		Various	14	24	—	36
Gas pipeline inspection and remediation costs		One to two years	42	13	33	12
Nuclear refueling outage costs	1	One to two years	30	12	37	16
Renewable resources and environmental initiatives		One to two years	50	6	170	48
Texas revenue surcharges		Less than one year	69	—	20	64
Sales true-up and revenue decoupling		One to two years	54	—	33	56
Other		Various	75	75	118	76
Total regulatory assets			$ 1,059	$ 2,871	$ 1,106	$ 2,738

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

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2022		Dec. 31, 2021 [(a)]	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(b)]	7	Various	$ 9	$ 3,110	$ 26	$ 3,230
Plant removal costs	1, 12	Various	—	1,819	—	1,655
Effects of regulation on employee benefit costs [(c)]		Various	—	247	—	235
Renewable resources and environmental initiatives		Various	6	173	1	101
Revenue decoupling		One to two years	—	77	9	41
ITC deferrals	1	Various	1	61	—	53
Formula rates		One to two years	32	17	19	11
Contract valuation adjustments [(d)]	1, 10	One to two years	175	1	56	1
Deferred natural gas, electric, steam energy/fuel costs		Less than one year	39	—	50	—
Conservation programs [(e)]	1	Less than one year	72	—	42	—
DOE settlement		Various	12	3	14	14
Other		Various	72	61	54	64
Total regulatory liabilities [(f)]			$ 418	$ 5,569	$ 271	$ 5,405

(a) Prior period amounts have been restated to conform with current year presentation.
(b) 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.
(c) Includes regulatory amortization and certain 2018 TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset.
(d) Includes the fair value of FTR instruments utilized/intended to offset the impacts of transmission system congestion.
(e) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.
(f) Revenue subject to refund of $67 million and $17 million for 2022 and 2021, respectively, is included in other current liabilities.

Xcel Energy's regulatory assets not earning a return include the unfunded portion of pension and retiree medical obligations and net AROs (i.e. deferrals for which cash has not been disbursed). In addition, regulatory assets included $1,020 million and $1,718 million at Dec. 31, 2022 and 2021 respectively, of past expenditures not earning a return. Amounts are predominately related to purchased natural gas and electric energy costs (including certain costs related to Winter Storm Uri), sales true-up and revenue decoupling, various renewable resources/environmental initiatives and certain prepaid pension amounts.

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 other borrowings outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2022	Year Ended Dec. 31 2022	2021	2020
Borrowing limit	$ 3,550	$3,550	$3,100	$3,100
Amount outstanding at period end	813	813	1,005	584
Average amount outstanding	416	552	1,399	1,126
Maximum amount outstanding	813	1,357	2,054	2,080
Weighted average interest rate, computed on a daily basis	4.20 %	1.47 %	0.57 %	1.45 %
Weighted average interest rate at period end	4.66	4.66	0.31	0.23

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

As of Dec. 31, 2022, NSP-Minnesota had $54 million outstanding letters of credit under the $75 million 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, 2022 and 2021, there were $43 million and $19 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.

Amended Credit Agreements — In September 2022, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each entered into an amended five-year credit agreement with a syndicate of banks. The aggregate borrowing limit was increased to $3.55 billion. The amended credit agreements have substantially the same terms and conditions as the prior agreements, with the following changes:

- Maturities extended from June 2024 to September 2027.
- Borrowing limit for Xcel Energy Inc. increased from $1.25 billion to $1.5 billion.
- Borrowing limit for NSP-Minnesota increased from $500 million to $700 million.

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]
	2022	2021		
Xcel Energy Inc. [c]	60 %	60 %	$ 350	2
NSP-Minnesota	48	47	150	2
NSP-Wisconsin	47	49	N/A	1
SPS	46	47	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, 2022, 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, 2022:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available
Xcel Energy Inc.	$ 1,500	$ 231	$ 1,269
PSCo	700	321	379
NSP-Minnesota	700	222	478
SPS	500	36	464
NSP-Wisconsin	150	47	103
Total	$ 3,550	$ 857	$ 2,693

(a) These credit facilities mature in September 2027.

(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, 2022 and 2021.

Long-Term Borrowings and Other Financing Instruments

Generally, the property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS is subject to the liens of their respective first mortgage indentures for the benefit of bondholders.

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	2022	2021
Unsecured senior notes	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	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	3.40	June 1, 2030	600	600
Unsecured senior notes [a]	2.35	Nov. 15, 2031	300	300
Unsecured senior notes [b]	4.60	June 1, 2032	700	—
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			(7)	(8)
Unamortized debt issuance cost			(35)	(33)
Current maturities			(500)	—
Total long-term debt			$ 5,338	$ 5,139

(a) 2021 financing.

(b) 2022 financing.

NSP-Minnesota

Financing Instrument	Interest Rate	Maturity Date	2022	2021
First mortgage bonds	2.15 %	Aug. 15, 2022	$ —	$ 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	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	2.60	June 1, 2051	700	700
First mortgage bonds [a]	3.20	April 1,2052	425	425
First mortgage bonds [b]	4.50	June 1, 2052	500	—
Other long-term debt			3	3
Unamortized discount			(45)	(44)
Unamortized debt issuance cost			(66)	(62)
Current maturities			(400)	(300)
Total long-term debt			$ 6,542	$ 6,447

(a) 2021 financing.

(b) 2022 financing.

NSP-Wisconsin

Financing Instrument	Interest Rate	Maturity Date	2022	2021
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	3.05	May 1, 2051	100	100
First mortgage bonds [(a)]	2.82	May 1, 2051	100	100
First mortgage bonds [(b)]	4.86	Sept. 15, 2052	100	—
Other long-term debt			—	1
Unamortized discount			(3)	(4)
Unamortized debt issuance cost			(11)	(10)
Total long-term debt			$ 1,086	$ 987

(a) 2021 financing.
(b) 2022 financing.

PSCo

Financing Instrument	Interest Rate	Maturity Date	2022	2021
First mortgage bonds	2.25 %	Sept. 15, 2022	$ —	$ 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	1.90	Jan. 15, 2031	375	375
First mortgage bonds [(a)]	1.875	June 15, 2031	750	750
First mortgage bonds [(b)]	4.10	June 1, 2032	300	—
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	2.70	Jan. 15, 2051	375	375
First mortgage bonds [(b)]	4.50	June 1, 2052	400	—
Unamortized discount			(37)	(33)
Unamortized debt issuance cost			(53)	(50)
Current maturities			(250)	(300)
Total long-term debt			$ 6,610	$ 6,167

(a) 2021 financing.
(b) 2022 financing.

SPS

Financing Instrument	Interest Rate	Maturity Date	2022	2021
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	3.15	May 1, 2050	350	350
First mortgage bonds [(a)]	3.15	May 1, 2050	250	250
First mortgage bonds [(b)]	5.15	June 1, 2052	200	—
Unamortized discount			(10)	(9)
Unamortized debt issuance cost			(29)	(28)
Total long-term debt			$ 3,211	$ 3,013

(a) 2020 financing re-opened in 2021.
(b) 2022 financing.

Other Subsidiaries

Financing Instrument	Interest Rate	Maturity Date	2022	2021
Various Eloigne affordable housing project notes	0.00% - 8.00%	2024 - 2055	$ 27	$ 27
Current maturities			(1)	(1)
Total long-term debt			$ 26	$ 26

Maturities of long-term debt:

(Millions of Dollars)	
2023	$ 1,151
2024	552
2025	1,103
2026	501
2027	501

Deferred Financing Costs — Deferred financing costs of approximately $193 million and $184 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2022 and 2021, respectively.

Equity through DRIP and Benefits Program — Xcel Energy issued $84 million and $74 million of equity through the DRIP and benefits programs in 2022 and 2021, respectively. The program allows shareholders to reinvest their dividends directly in Xcel Energy Inc. common stock.

ATM Equity Offering — In November 2021, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $800 million of its common stock through an ATM program. In 2021, 5.33 million shares of common stock were issued (approximately $350 million). In 2022, 4.30 million shares of common stock were issued (approximately $300 million). As of Dec. 31, 2022, approximately $150 million remained available for sale under the ATM program.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2022 and 2021
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, 2022	Common Stock Outstanding (Shares) as of Dec. 31, 2021
1,000,000,000	$ 2.50	549,578,018	544,025,269

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, 2022:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2022
NSP-Minnesota	47.2 %	57.6 %	52.3 %
NSP-Wisconsin	52.5	N/A	52.8
SPS [(a)]	45.0	55.0	54.3

(a) Excludes short-term debt.

(Amounts in Millions)	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1,446	$ 14,984	$ 16,140
NSP-Wisconsin [(a)]	11	2,280	N/A
SPS [(b)]	540	7,094	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, 2022:

(Millions of Dollars)	Long-Term Debt	Short-Term Debt
NSP-Minnesota	52.8% of total capitalization [(a)]	$ 2,400 [(a)]
NSP-Wisconsin	$ 50	150
SPS	—	600
PSCo	1,300	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.

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:

(Millions of Dollars)	Year Ended Dec. 31, 2022 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 3,542	$ 1,814	$ 53	$ 5,409
C&I	5,807	998	32	6,837
Other	148	—	10	158
Total retail	9,497	2,812	95	12,404
Wholesale	1,354	—	—	1,354
Transmission	675	—	—	675
Other	97	178	—	275
Total revenue from contracts with customers	11,623	2,990	95	14,708
Alternative revenue and other	500	90	12	602
Total revenues	$ 12,123	$ 3,080	$ 107	$ 15,310

(Millions of Dollars)	Year Ended Dec. 31, 2021 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

(Millions of Dollars)	Year Ended Dec. 31, 2020 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

7. Income Taxes

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:

	2022	2021 [(a)]	2020 [(a)]
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	4.9	5.0	4.9
(Decreases) increases in tax from:			
Wind PTCs [(b)]	(27.4)	(23.4)	(15.7)
Plant regulatory differences [(c)]	(5.5)	(6.2)	(7.6)
Other tax credits, net NOL & tax credit allowances	(1.3)	(1.1)	(1.2)
NOL Carryback	—	—	(0.9)
Other, net	(0.1)	0.1	(0.9)
Effective income tax rate	(8.4)%	(4.6)%	(0.4)%

(a) Prior period amounts have been restated to conform with current year presentation.

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

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

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

(Millions of Dollars)	2022	2021	2020
Current federal tax expense (benefit)	$ 1	$ 15	$ (13)
Current state tax expense (benefit)	3	(2)	2
Current change in unrecognized tax expense	5	1	18
Deferred federal tax benefit	(239)	(183)	(89)
Deferred state tax expense	96	99	91
Deferred change in unrecognized tax expense (benefit)	3	5	(10)
Deferred ITCs	(4)	(5)	(5)
Total income tax benefit	$ (135)	$ (70)	$ (6)

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

(Millions of Dollars)	2022	2021	2020
Deferred tax (benefit) expense excluding items below	$ (138)	$ 148	$ 237
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	8	(221)	(247)
Tax (benefit) expense allocated to other comprehensive income and other	(10)	(6)	2
Deferred tax benefit	$ (140)	$ (79)	$ (8)

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

(Millions of Dollars)	2022	2021 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 6,442	$ 6,231
Regulatory assets	508	560
Operating lease assets	325	351
Deferred fuel costs	222	262
Pension expense	159	175
Other	92	88
Total deferred tax liabilities	$ 7,748	$ 7,667
Deferred tax assets:		
Tax credit carryforward	$ 1,679	$ 1,261
Regulatory liabilities	742	742
Operating lease liabilities	325	351
Other employee benefits	102	119
NOL carryforward	57	247
NOL and tax credit valuation allowances	(62)	(64)
Deferred ITCs	14	15
Other	135	102
Total deferred tax assets	$ 2,992	$ 2,773
Net deferred tax liability	$ 4,756	$ 4,894

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

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)	2022	2021
Federal NOL carryforward	$ 20	$ 765
Federal tax credit carryforwards	1,593	1,172
State NOL carryforwards	1,022	1,648
Valuation allowances for state NOL carryforwards	(3)	(3)
State tax credit carryforwards, net of federal detriment [(a)]	85	89
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(62)	(64)

(a) State tax credit carryforwards are net of federal detriment of $23 million and $24 million as of Dec. 31, 2022 and 2021.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $16 million and $17 million as of Dec. 31, 2022 and 2021.

Federal carryforward periods expire starting 2032 and state carryforward periods expire starting 2022.

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.

Unrecognized Tax Benefits

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

Tax Year(s)	Expiration
2014 - 2016	March 2024
2019	October 2023

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, 2022, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Tax Year(s)	Expiration
Colorado	2014 - 2016	March 2025
Colorado	2018	September 2023
Minnesota	2014 - 2016	September 2024
Minnesota	2018	June 2023
Texas	2016	May 2023
Texas	2017	July 2025
Texas	2018	November 2023
Wisconsin	2016 - 2017	April 2023
Wisconsin	2018	October 2023

- In 2020, Minnesota began an audit of tax years 2015-2018. In 2022, the state of Minnesota issued its audit report without any material adjustments.
- In 2021, Texas began an audit of tax years 2016-2019. As of Dec. 31, 2022, no material adjustments have been proposed.
- In 2021, Wisconsin began an audit of tax years 2016-2019. As of Dec. 31, 2022, no material adjustments have been proposed.
- No other state income tax audits are in progress for its major operating jurisdictions as of Dec. 31, 2022.

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, 2022	Dec. 31, 2021
Unrecognized tax benefit — Permanent tax positions	$ 55	$ 47
Unrecognized tax benefit — Temporary tax positions	12	11
Total unrecognized tax benefit	$ 67	$ 58

Changes in unrecognized tax benefits:

(Millions of Dollars)	2022	2021	2020
Balance at Jan. 1	$ 58	$ 52	$ 44
Additions based on tax positions related to the current year	7	5	9
Reductions based on tax positions related to the current year	—	—	(2)
Additions for tax positions of prior years	6	2	35
Reductions for tax positions of prior years	(1)	(1)	(34)
Reductions for tax positions related to settlements with taxing authorities	(1)	—	—
Reductions for tax positions related to statute of limitations	(2)	—	—
Balance at Dec. 31	$ 67	$ 58	$ 52

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

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
NOL and tax credit carryforwards	$ (40)	$ (36)

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 $40 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)	2022	2021	2020
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (3)	$ (3)	$ —
Interest expense related to unrecognized tax benefits	(1)	—	(3)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (4)	$ (3)	$ (3)

No penalties were accrued related to unrecognized tax benefits as of Dec. 31, 2022, 2021 or 2020.

8. Share-Based Compensation

Incentive Plan Including Share-Based Compensation — Xcel Energy has authorized 7.0 million equity shares under an incentive plan (the Amended and Restated 2015 Omnibus Incentive Plan).

Equity Awards — Xcel Energy's Board of Directors has granted equity awards under the 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 time-based equity shares subject only to service conditions were granted annually in 2022, 2021 and 2020.

The performance conditions for a portion of the awards granted from 2020 to 2022 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:

(Units in Thousands)	2022	2021	2020
Granted units	395	421	411
Weighted average grant date fair value	$ 68.43	$ 66.03	$ 62.92

Equity awards vested:

(Units in Thousands, Fair Value in Millions)	2022	2021	2020
Vested Units	319	392	442
Total Fair Value	$ 22	$ 27	$ 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, 2022	695	$ 64.59
Granted	395	68.43
Forfeited	(96)	65.53
Vested	(319)	63.03
Dividend equivalents	33	65.40
Nonvested Units at Dec. 31, 2022	708	67.35

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)	2022	2021	2020
Granted units	29	31	33
Weighted average grant date fair value	$ 71.97	$ 68.15	$ 61.61

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2022	604	$ 39.27
Granted	29	71.97
Units distributed	(52)	38.16
Dividend equivalents	16	67.79
Stock equivalent units at Dec. 31, 2022	597	41.75

Liability Awards — Xcel Energy's Board of Directors has granted TSR liability awards under the 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%.

Liability awards granted:

(In Thousands)	2022	2021	2020
Awards granted	165	221	212

Liability awards settled:

(Units In Thousands, Settlement Amount in Millions)	2022	2021	2020
Awards settled	411	446	476
Settlement amount (cash, common stock and deferred amounts)	$ 27	$ 27	$ 33

TSR liability awards of $21 million were settled in cash in 2022.

Share-Based Compensation Expense — Award settlement determination (permitting cash or share settlement) is made by Xcel Energy, not the participants. Equity 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 are accounted for as liabilities, as historically they are partially settled in cash. 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)	2022	2021	2020
Cost for share-based awards [(a)]	$ 36	$ 31	$ 73
Tax benefit recognized in income	9	8	19

(a) Compensation costs for share-based payments are included in O&M expense. Amount for equity awards (non-cash) amounted to $20 million in 2022.

There was approximately $37 million and $28 million as of Dec. 31, 2022 and 2021, respectively, 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 1.8 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 — 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)	2022	2021	2020
Basic	547	539	527
Diluted [(a)]	547	540	528

(a) Diluted common shares outstanding included common stock equivalents of 0.3 million, 0.3 million and 1.1 million shares for 2022, 2021 and 2020, respectively.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

- 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 actively traded instruments with observable actual trading prices.
- Level 2 — Pricing inputs are other than actual trading 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 include those valued with models requiring significant judgment or estimation.

Specific valuation methods include:

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 funds 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 funds 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 contracts relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges, the significance of the use of less observable inputs on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The values of these instruments are derived from, and designed to offset, the costs of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of these instruments.

FTRs are recognized at fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3 classification.

Net congestion costs, including the impact of FTR settlements, are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Non-Derivative Fair Value Measurements

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 billion and $1.3 billion as of Dec. 31, 2022 and 2021, respectively, and unrealized losses were $90 million and $7 million as of Dec. 31, 2022 and 2021, respectively.

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

	Dec. 31, 2022					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 29	$ 29	$ —	$ —	$ —	$ 29
Commingled funds	803	—	—	—	1,178	1,178
Debt securities	738	—	669	6	—	675
Equity securities	406	999	1	—	—	1,000
Total	$ 1,976	$ 1,028	$ 670	$ 6	$ 1,178	$ 2,882

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $219 million of equity method investments and $133 million of rabbi trust assets and other miscellaneous investments.

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

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

For the years ended Dec. 31, 2022 and 2021, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2022:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	$ 6	$ 204	$ 250	$ 215	$ 675

Rabbi Trusts

Xcel Energy has established rabbi trusts to provide partial funding for future distributions of deferred compensation plan. The fair value of assets held in the rabbi trusts were $80 million and $109 million at Dec. 31, 2022 and 2021, respectively, comprised of cash equivalents and mutual funds (level 1 valuation methods). Amounts are reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Activities and 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, and utility commodity prices.

Interest Rate Derivatives — Xcel Energy enters into contracts that effectively fix the interest rate on a specified principal amount of a hypothetical future debt issuance. These financial swaps net settle based on changes in a specified benchmark interest rate, acting as a hedge of changes in market interest rates that will impact specified anticipated debt issuances. These derivative instruments are designated as cash flow hedges for accounting purposes, with changes in fair value prior to occurrence of the hedged transactions recorded as other comprehensive income.

As of Dec. 31, 2022, accumulated other comprehensive loss related to interest rate derivatives included $2 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, 2022, Xcel Energy had unsettled interest swaps outstanding with a notional amount of $40 million. These interest rate derivatives were designated as cash flow hedges, with changes in fair value recorded to other comprehensive income.

See Note 13 for the financial impact of qualifying interest rate cash flow hedges on Xcel Energy's accumulated other comprehensive loss included in the consolidated statements of common stockholder's equity and in the consolidated statements of comprehensive income.

Wholesale and Commodity Trading — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Derivative instruments entered into for trading purposes are presented in the consolidated statements of income as electric revenues, net of any sharing with customers. These activities are not intended to mitigate commodity price risk associated with regulated electric and natural gas operations. Sharing of these margins is determined through state regulatory proceedings as well as the operation of the FERC-approved joint operating agreement.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale and FTRs.

The most significant derivative positions outstanding at December 31, 2022 and 2021 for this purpose relate to FTR instruments administered by MISO and SPP. These instruments are intended to offset the impacts of transmission system congestion.

Higher congestion costs in recent years have led to an increase in the fair value of FTRs. Settlements of FTRs are shared with electric customers through fuel and purchased energy cost-recovery mechanisms.

When Xcel Energy enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, the instruments are not typically 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, 2022, Xcel Energy had no commodity contracts designated as cash flow hedges.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [a][b]	Dec. 31, 2022	Dec. 31, 2021
MWh of electricity	61	80
MMBtu of natural gas	131	156

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

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

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented 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, 2022, four of Xcel Energy's ten most significant counterparties for these activities, comprising $75 million or 37% of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings.

Four of the ten most significant counterparties, comprising $63 million or 32% of this credit exposure, were not rated by these external ratings agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade.

Two of these significant counterparties, comprising $62 million or 31% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Six of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

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, 2022 and 2021, there were $4 million and $3 million, respectively, of derivative liabilities 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 other financing arrangements related to payment terms or other covenants.

As of Dec. 31, 2022 and 2021, there were approximately $76 million and $64 million of derivative liabilities with such underlying contract provisions, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired.

Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2022 and 2021.

Recurring Derivative Fair Value Measurements

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, 2022		
Derivatives designated as cash flow hedges		
Interest rate	$ 22	$ —
Total	$ 22	$ —
Other derivative instruments		
Electric commodity	$ —	$ (10)
Natural gas commodity	—	(16)
Total	$ —	$ (26)
Year Ended Dec. 31, 2021		
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)

	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, 2022			
Derivatives designated as cash flow hedges			
Interest rate	$ 7 [(a)]	$ —	$ —
Total	$ 7	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 25 [(b)]
Electric commodity	—	3 [(c)]	—
Natural gas commodity	—	10 [(d)]	(27) [(d)(e)]
Total	$ —	$ 13	$ (2)
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)(e)]
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)(e)]
Total	$ —	$ 7	$ (14)

(a) Recorded to interest charges.

(b) Recorded to electric revenues. Presented amounts do not reflect non-derivative transactions or margin sharing with customers.

(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. FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.

(d) Recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

(e) Relates primarily to option premium amortization.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2022, 2021 and 2020.

Derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	Dec. 31, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 32	$ 259	$ 33	$ 324	$ (242)	$ 82	$ 22	$ 137	$ 21	$ 180	$ (134)	$ 46
Electric commodity	—	—	177	177	(2)	175	—	—	57	57	(1)	56
Natural gas commodity	—	19	—	19	—	19	—	18	—	18	—	18
Total current derivative assets	$ 32	$ 278	$ 210	$ 520	$ (244)	276	$ 22	$ 155	$ 78	$ 255	$ (135)	120
PPAs [b]						3						3
Current derivative instruments						$ 279						$ 123
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 34	$ 71	$ 74	$ 179	$ (89)	$ 90	$ 16	$ 63	$ 89	$ 168	$ (107)	$ 61
Total noncurrent derivative assets	$ 34	$ 71	$ 74	$ 179	$ (89)	90	$ 16	$ 63	$ 89	$ 168	$ (107)	61
PPAs [b]						3						6
Noncurrent derivative instruments						$ 93						$ 67

	Dec. 31, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total
Current derivative liabilities												
Derivatives designated as cash flow hedges:												
Interest rate	$ —	$ 1	$ —	$ 1	$ —	$ 1	$ —	$ —	$ —	$ —	$ —	$ —
Other derivative instruments:												
Commodity trading	$ 29	$ 297	$ 6	$ 332	$ (287)	$ 45	$ 19	$ 148	$ 20	$ 187	$ (143)	$ 44
Electric commodity	—	—	2	2	(2)	—	—	—	1	1	(1)	—
Natural gas commodity	—	13	—	13	—	13	—	8	—	8	—	8
Total current derivative liabilities	$ 29	$ 311	$ 8	$ 348	$ (289)	59	$ 19	$ 156	$ 21	$ 196	$ (144)	52
PPAs [b]						17						17
Current derivative instruments						$ 76						$ 69
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 43	$ 97	$ 41	$ 181	$ (98)	$ 83	$ 18	$ 48	$ 127	$ 193	$ (128)	$ 65
Total noncurrent derivative liabilities	$ 43	$ 97	$ 41	$ 181	$ (98)	83	$ 18	$ 48	$ 127	$ 193	$ (128)	65
PPAs [b]						30						40
Noncurrent derivative instruments						$ 113						$ 105

(a) Xcel Energy nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement. At Dec. 31, 2022 and 2021, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2022 and 2021, derivative assets and liabilities include rights to reclaim cash collateral of $53 million and $30 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) Xcel Energy currently applies the normal purchase exception to qualifying PPAs. Balance relates to specific contracts that were previously recognized at fair value prior to applying the normal purchase exception, and are 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)	2022	2021	2020
Balance at Jan. 1	$ 19	$ (49)	$ 4
Purchases [(a)]	406	65	51
Settlements [(a)]	(350)	(158)	(73)
Net transactions recorded during the period:			
Gains (losses) recognized in earnings [(b)]	151	49	(39)
Net gains recognized as regulatory assets and liabilities [(a)]	10	112	8
Balance at Dec. 31	$ 236	$ 19	$ (49)

(a) Relates primarily to NSP-Minnesota and SPS FTR instruments administered by MISO and SPP.

(b) Relates to commodity trading and is subject to substantial offsetting losses and gains on derivative instruments categorized as levels 1 and 2 in the income statement. See above tables for the income statement impact of derivative activity, including commodity trading gains and losses.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2022		2021	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 23,964	$ 20,897	$ 22,380	$ 25,232

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2022 and 2021, 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 4.89, 2.03 and 1.89% in 2022, 2021, and 2020, 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, 2022 and 2021 were $11 million and $43 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $17 million in 2022 and $4 million in 2021.

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 the long-term projected return levels from investment experts.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2022 were below the assumed level of 6.49%.
- Investment returns in 2021 were above the assumed level of 6.49%.
- Investment returns in 2020 were above the assumed level of 6.87%.
- In 2023, expected investment-return assumption is 6.93%.

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:

(Millions of Dollars)	Dec. 31, 2022 (a) Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2021 (a) Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 129	$ —	$ —	$ —	$ 129	$ 133	$ —	$ —	$ —	$ 133
Commingled funds	935	—	—	882	1,817	1,324	—	—	1,143	2,467
Debt securities	—	682	3	—	685	—	959	5	—	964
Equity securities	47	—	—	—	47	67	—	—	—	67
Other	—	7	—	—	7	—	7	—	32	39
Total	$ 1,111	$ 689	$ 3	$ 882	$ 2,685	$ 1,524	$ 966	$ 5	$ 1,175	$ 3,670

(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:

(Millions of Dollars)	Dec. 31, 2022 (a) Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2021 (a) Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 31	$ —	$ —	$ —	$ 31	$ 28	$ —	$ —	$ —	$ 28
Insurance contracts	—	41	—	—	41	—	52	—	—	52
Commingled funds	54	—	—	63	117	64	—	—	77	141
Debt securities	—	175	1	—	176	—	218	1	—	219
Other	—	(1)	—	—	(1)	—	2	—	—	2
Total	$ 85	$ 215	$ 1	$ 63	$ 364	$ 92	$ 272	$ 1	$ 77	$ 442

(a) See Note 10 for further information on fair value measurement inputs and methods.

Immaterial assets were transferred in or out of Level 3 for 2022. No assets were transferred in or out of Level 3 for 2021.

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2021 to Dec. 31, 2022, 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)	2022	2021	2022	2021
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,718	$ 3,964	$ 511	$ 574
Service cost	97	104	2	2
Interest cost	110	104	15	15
Plan amendments	1	5	—	—
Actuarial gain	(703)	(94)	(85)	(41)
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	2	2
Benefit payments (a)	(352)	(365)	(48)	(49)
Obligation at Dec. 31	$ 2,871	$ 3,718	$ 405	$ 511
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 3,670	$ 3,599	$ 442	$ 452
Actual return on plan assets	(683)	305	(51)	16
Employer contributions	50	131	13	15
Plan participants' contributions	—	—	8	8
Benefit payments	(352)	(365)	(48)	(49)
Fair value of plan assets at Dec. 31	$ 2,685	$ 3,670	$ 364	$ 442
Funded status of plans at Dec. 31	$ (186)	$ (48)	$ (41)	$ (69)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Noncurrent assets	$ 15	$ 19	$ 33	$ 33
Current liabilities	—	—	(2)	(4)
Noncurrent liabilities	(201)	(67)	(72)	(98)
Net amounts recognized	$ (186)	$ (48)	$ (41)	$ (69)

(a) Includes approximately $195 million in 2022 and $197 million in 2021 of lump-sum benefit payments used in the determination of a settlement charge.

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	**2022**	**2021**	**2022**	**2021**
Discount rate for year-end valuation	5.80 %	3.08 %	5.80 %	3.09 %
Expected average long-term increase in compensation level	4.25	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	6.50 %	5.30 %
Health care costs trend rate — initial: Post-65	N/A	N/A	5.50 %	4.90 %
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	7	4

Accumulated benefit obligation for the pension plan was $2,672 million and $3,469 million as of Dec. 31, 2022 and 2021, 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:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
Service cost	$ 97	$ 104	$ 95	$ 2	$ 2	$ 1
Interest cost	110	104	125	15	15	18
Expected return on plan assets	(208)	(206)	(208)	(18)	(18)	(19)
Amortization of prior service credit	(1)	(1)	(4)	(6)	(8)	(8)
Amortization of net loss	75	107	100	2	5	4
Settlement charge [(a)]	71	59	—	—	—	—
Net periodic pension cost (credit)	144	167	108	(5)	(4)	(4)
Effects of regulation	(30)	(46)	9	3	2	3
Net benefit cost (credit) recognized for financial reporting	$ 114	$ 121	$ 117	$ (2)	$ (2)	$ (1)
Significant Assumptions Used to Measure Costs:						
Discount rate	3.08 %	2.71 %	3.49 %	3.09 %	2.65 %	3.47 %
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	6.49	6.87	4.10	4.10	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 2022 and 2021, as a result of lump-sum distributions during each plan year, Xcel Energy recorded a total pension settlement charge of $71 million and $59 million, respectively, the majority of which was not recognized due to the effects of regulation. A total of $9 million and $7 million was recorded in the consolidated statements of income in 2022 and 2021, respectively. There were no settlement charges recorded for the qualified pension plans in 2020.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2022**	**2021**	**2022**	**2021**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 1,021	$ 978	$ 63	$ 81
Prior service credit	(7)	(9)	(1)	(7)
Total	$ 1,014	$ 969	$ 62	$ 74
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	$ 21	$ 74	$ —	$ —
Noncurrent regulatory assets	943	846	78	90
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(20)	(19)
Deferred income taxes	14	13	1	1
Net-of-tax accumulated other comprehensive income	36	36	4	3
Total	$ 1,014	$ 969	$ 62	$ 74
Measurement date	Dec. 31, 2022	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2021

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 2020 - 2023 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $50 million in January 2023.
- $50 million in 2022.
- $131 million in 2021.
- $150 million in 2020.

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:

- $12 million expected during 2023.
- $13 million during 2022.
- $15 million during 2021.
- $11 million during 2020.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2022	2021	2022	2021
Domestic and international equity securities	33 %	33 %	16 %	15 %
Long-duration fixed income securities	38	37	—	—
Short-to-intermediate fixed income securities	9	11	71	71
Alternative investments	18	17	12	8
Cash	2	2	1	6
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 — There were no significant plan amendments made in 2022 or 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
2023	$ 283	$ 42	$ 2	$ 40
2024	249	41	2	39
2025	249	40	2	38
2026	246	39	2	37
2027	243	37	2	35
2028 - 2032	1,162	167	12	155

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $46 million in 2022, $43 million in 2021 and $42 million in 2020.

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.). The Court issued a ruling on June 30, 2022 granting plaintiffs' class certification. Defendants will work together to prepare and file a petition appealing the class certification ruling to the Seventh Circuit. Xcel Energy has concluded that a loss is remote for the remaining lawsuit.

Comanche Unit 3 Litigation — In 2021, CORE filed a lawsuit in Denver County District Court, alleging PSCo breached ownership agreement terms by failing to operate Comanche Unit 3 in accordance with prudent utility practices. In January 2022, the Court granted PSCo's motion to dismiss CORE's claims for unjust enrichment, declaratory judgment and damages for replacement power costs. In April 2022, CORE filed a supplement to include the January 2022 outage and damages related to this event. Also in 2022, CORE sent notice of withdrawal from the ownership agreement based on the same alleged breaches. In February 2023, CORE disclosed its expert witness, who estimated damages incurred of $270 million. Also in February 2023, the court granted PSCo's motion precluding CORE from seeking damages related to its withdrawal as part of the lawsuit. PSCo continues to believe CORE's claims are without merit and disputes CORE's right to withdraw.

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.

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 fuel clause adjustment.

In March 2019, the MPUC approved NSP-Minnesota's settlement refund proposal. Additionally, the MPUC decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of an appeal pending between GE and NSP-Minnesota's insurers.

In February 2020, the Minnesota Court of Appeals affirmed the district court's judgment in favor of GE. In March 2020, NSP-Minnesota's insurers filed a petition seeking additional review by the Minnesota Supreme Court. In April 2020, the Minnesota Supreme Court denied the insurers' petition for further review, ending the litigation.

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

A final decision by the MPUC is expected in mid-2024. A loss related to this matter is deemed remote.

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

The FERC subsequently issued various related orders (including Opinion Nos. 569, 569A and 569B) related to ROE methodology/calculations and timing. NSP-Minnesota has processed refunds to customers for applicable complaint periods based on the ROE in the most recent applicable opinions.

The MISO TOs and various other parties have filed petitions for review of the FERC's most recent applicable opinions at the D.C. Circuit. In August 2022, the D.C. Circuit ruled that FERC had not adequately supported its conclusions, vacated FERC's related orders and remanded the issue back to FERC for further proceedings, which remain pending. Additional exposure, if any related to this matter is expected to be immaterial.

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 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 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 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of the FERC's orders at the D.C. Circuit. In 2021, the D.C. Circuit issued a decision denying these appeals and upholding the FERC's orders. Refunds received by SPS are expected to be given back to SPS customers through future rates.

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

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, 2022, the full-year net capacity factor exceeded the guaranteed level, resulting in no refund liability for 2022.

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 9 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 applicable landfills and surface impoundments as well as perform corrective actions where offsite groundwater has been impacted.

As of Dec. 31, 2022, Xcel Energy had eight regulated ash units in operation.

PSCo is currently exploring an agreement with a third party that would excavate and process ash for beneficial use (at two sites) and perform restoration at one site at a cost of approximately $45 million. An estimated liability has been recorded and amounts are expected to be fully recoverable through regulatory mechanisms.

Investigation and feasibility studies for additional corrective action related to offsite groundwater are ongoing (three sites). While the results are uncertain, additional costs are estimated to be up to $35 million. A liability has been recorded for the portion estimable/probable and are expected to be fully recoverable through regulatory mechanisms.

Federal Clean Water Act Section 316(b) — The Federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure they reflect the best technology available for minimizing impingement and entrainment of aquatic species.

Estimated capital expenditures of approximately $45 million may be required for NSP-Minnesota to comply with the requirements pending approval of mitigation plans from the MPCA. Xcel Energy anticipates these costs will be recoverable through regulatory mechanisms.

Environmental Requirements — Air

Reasonable Progress Rule and BART — 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 which would require the installation of dry scrubbers on Tolk Units 1 and 2; compliance would have been required by February 2021. SPS appealed the EPA's decision and obtained a stay of the final rule.

In 2017, the EPA adopted a final BART rule for Texas. Under that rule, Harrington Units 1, 2, and 3 and Tolk Units 1 and 2 participate in intrastate SO2 budget and trading program. The rule also implemented participation in a federal ozone season NOx budget and trading program, named the Cross State Air Pollution Rule. The EPA is reconsidering this rule.

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 $2.9 billion and $3.3 billion for 2022 and 2021, respectively.

Xcel Energy's AROs were as follows:

(Millions of Dollars)	Jan. 1, 2022	Amounts Incurred (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2022
Electric					
Nuclear	$ 2,056	$ —	$ 104	$ —	$ 2,160
Wind	478	25	19	(8)	514
Steam, hydro and other production	288	34	12	14	348
Distribution	47	—	1	—	48
Natural gas					
Transmission and distribution	271	—	12	23	306
Miscellaneous	8	—	—	(7)	1
Common					
Miscellaneous	1	—	—	—	1
Non-utility					
Miscellaneous	2	—	—	—	2
Total liability	$ 3,151	$ 59	$ 148	$ 22	$ 3,380

(a) Amounts incurred related to the wind farms placed in service in 2022 for NSP-Minnesota (Dakota Range and Rock Aetna) and steam production pond remediation costs for PSCo.

(b) In 2022, 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.

(Millions of Dollars)	Jan. 1, 2021	Amounts Incurred (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2021
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.

Indeterminate AROs — Outside of the recorded asbestos 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, 2022. 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 $13.7 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.2 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 $20 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 $12 million for business interruption insurance and $32 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 50 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 to 2040. 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 authorized retirement dates, which can be different than the currently approved NRC operating licenses. These decommissioning activities are planned to be completed at both facilities by 2101.

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. The MPUC reaffirmed a 60-year DECON scenario, where Monticello continues operations under a 10-year license extension (approved in August 2022). NRC approval of the extension is pending.

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. The 2020 nuclear decommissioning filing was approved by the MPUC and became effective in 2022.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. NSP-Minnesota had $2.9 billion and $3.3 billion of assets held in external decommissioning trusts at Dec. 31, 2022, and 2021, respectively.

See Note 10 to the consolidated financial statements for additional discussion.

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 4.1%). 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, 2022	Dec. 31, 2021
PPAs	$ 1,669	$ 1,656
Other	244	225
Gross operating lease ROU assets	1,913	1,881
Accumulated amortization	(709)	(590)
Net operating lease ROU assets	$ 1,204	$ 1,291

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, 2022	Dec. 31, 2021
Gas storage facilities	$ 160	$ 201
Gas pipeline	21	21
Gross finance lease ROU assets	181	222
Accumulated amortization	(64)	(97)
Net finance lease ROU assets	$ 117	$ 125

Components of lease expense:

(Millions of Dollars)	2022	2021	2020
Operating leases			
PPA capacity payments	$ 241	$ 251	$ 238
Other operating leases [(a)]	39	36	26
Total operating lease expense [(b)]	$ 280	$ 287	$ 264
Finance leases			
Amortization of ROU assets	$ 4	$ 7	$ 7
Interest expense on lease liability	16	17	18
Total finance lease expense	$ 20	$ 24	$ 25

(a) Includes short-term lease expense of $6 million for 2022 and $5 million for 2021 and 2020.

(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, 2022:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [(c)]
2023	$ 231	$ 33	$ 264	$ 10
2024	238	28	266	10
2025	217	23	240	10
2026	161	18	179	9
2027	90	18	108	8
Thereafter	326	74	400	181
Total minimum obligation	1,263	194	1,457	228
Interest component of obligation	(170)	(32)	(202)	(162)
Present value of minimum obligation	$ 1,093	162	1,255	66
Less current portion			(217)	(2)
Noncurrent operating and finance lease liabilities			$ 1,038	$ 64
Weighted-average remaining lease term in years			7.9	37.8

(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 2033.

(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 $182 million, $149 million and $112 million in 2022, 2021 and 2020, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $75 million, $69 million and $75 million in 2022, 2021 and 2020, 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, 2022, 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)]
2023	$ 77	$ 50
2024	72	45
2025	29	51
2026	10	48
2027	7	55
Thereafter	3	28
Total	$ 198	$ 277

(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 2023 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, 2022:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2023	$ 628	$ 144	$ 684	$ 316
2024	343	112	8	290
2025	90	158	1	276
2026	53	37	—	276
2027	55	155	—	225
Thereafter	2	194	—	607
Total	$ 1,171	$ 800	$ 693	$ 1,990

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, however it 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 3,961 MW and 4,062 MW of capacity under these long-term PPAs at Dec. 31, 2022 and 2021, respectively, 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 2024 and December 2027, respectively. 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 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 with affordable rental housing activities that qualify for low-income housing tax credits.

Eloigne and NSP-Wisconsin, as primary beneficiaries of these activities, consolidate these limited partnerships in their consolidated financial statements.

Amounts reflected in Xcel Energy's consolidated balance sheets for these investments include $44 million of assets and $35 million of liabilities at Dec. 31, 2022, and $45 million of assets and $35 million of liabilities at Dec. 31, 2021.

Other

Technology Agreements — Xcel Energy has several contracts for information technology services that extend through 2027. The contracts are cancelable, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $181 million, $103 million and $110 million associated with these vendors in 2022, 2021 and 2020, respectively.

Committed minimum payments under these obligations as follows:

(Millions of Dollars)	Minimum Payments
2023	$ 24
2024	13
2025	12
2026	11
2027	10
Thereafter	—

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, 2022 and 2021, 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 $62 million and $60 million at Dec. 31, 2022 and 2021 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:

	2022		
(Millions of Dollars)	Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (75)	$ (48)	$ (123)
Other comprehensive gain before reclassifications	16	5	21
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	5 [(a)]	—	5
Amortization of net actuarial loss	—	4 [(b)]	4
Net current period other comprehensive income	21	9	30
Accumulated other comprehensive loss at Dec. 31	$ (54)	$ (39)	$ (93)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

	2021		
(Millions of Dollars)	Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (85)	$ (56)	$ (141)
Other comprehensive gain before reclassifications	4	—	4
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	6 [(a)]	—	6
Amortization of net actuarial loss	—	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.

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 $219 million and $208 million as of Dec. 31, 2022 and 2021, respectively, included in the natural gas utility and all other segments.

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

Reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations, which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

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

Xcel Energy's segment information:

(Millions of Dollars)	2022	2021	2020
Regulated Electric			
Operating revenues — external	$ 12,123	$ 11,205	$ 9,802
Intersegment revenue	2	2	2
Total revenues	$ 12,125	$ 11,207	$ 9,804
Depreciation and amortization	2,122	1,855	1,673
Interest charges and financing costs	636	568	534
Income tax (benefit) expense	(162)	(96)	1
Net income	1,631	1,478	1,407
Regulated Natural Gas			
Operating revenues — external	$ 3,080	$ 2,132	$ 1,636
Intersegment revenue	2	2	1
Total revenues	$ 3,082	$ 2,134	$ 1,637
Depreciation and amortization	276	254	252
Interest charges and financing costs	86	75	71
Income tax expense	68	54	17
Net income	264	231	190
All Other			
Total revenues	$ 107	$ 94	$ 88
Depreciation and amortization	15	12	23
Interest charges and financing costs	203	173	193
Income tax benefit	(41)	(28)	(24)
Net loss	(159)	(112)	(124)
Consolidated Total			
Total revenues	$ 15,314	$ 13,435	$ 11,529
Reconciling eliminations	(4)	(4)	(3)
Total operating revenues	$ 15,310	$ 13,431	$ 11,526
Depreciation and amortization	2,413	2,121	1,948
Interest charges and financing costs	925	816	798
Income tax (benefit) expense	(135)	(70)	(6)
Net income	1,736	1,597	1,473

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, 2022, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter ended Dec. 31, 2022 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, 2022 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 2023 Annual Meeting of Shareholders, which is expected to occur on April 11, 2023, 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 2023 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 2023 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 2023 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 2023 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, 2022.
	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, 2022, 2021, and 2020.
	Consolidated Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2022, 2021, and 2020.
	Consolidated Statements of Cash Flows — For each of the three years ended Dec. 31, 2022, 2021, and 2020.
	Consolidated Balance Sheets — As of Dec. 31, 2022 and 2021.
	Consolidated Statements of Common Stockholders' Equity — For each of the three years ended Dec. 31, 2022, 2021, and 2020.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2022, 2021, and 2020.
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 as of Dec. 1, 2000, by and between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to 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 as of June 1, 2006, by and between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $300 million of 6.50% Senior Notes, Series due July 1, 2036	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 Computershare Trust Company, N.A. (as successor to 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, by and between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $250 million of 4.80% Senior Notes, Series due Sept. 15, 2041	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	4.01
4.07*	Supplemental Indenture No. 8, dated as of June 1, 2015, by and between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $250 million aggregate principal amount of 3.30% Senior Notes, Series due June 1, 2025	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 Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association, as Trustee), creating $500 million aggregate principal amount of 3.35% Senior Notes, Series due Dec. 1, 2026	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 Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $500 million aggregate principal amount of 4.00% Senior Notes, Series due June 15, 2028	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 Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $500 million aggregate principal amount of 2.60% Senior Notes, Series due Dec 1. 2029 and $500 million aggregate principal amount of 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 Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee creating $600 million aggregate 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 Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee, creating $500 million aggregate 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 aggregate principal amount of 1.75% Senior Notes, Series due March 15, 2027 and $300 million aggregate principal amount of 2.35% Senior Notes, Series due Nov. 15, 2031	Xcel Energy Inc. Form 8-K dated Nov. 3, 2021	4.01

4.14*	Supplemental Indenture No. 16, dated as of May 6, 2022, by and between Xcel Energy Inc. and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as trustee, creating $700 million aggregate principal amount of 4.60% Senior Notes, Series due June 1, 2032	Xcel Energy Form 8-K dated May 6, 2022	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 Sept. 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*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, 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, and Citibank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association., as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.01
10.26*+	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 Dec. 10, 2021	10.01
NSP-Minnesota			
4.15*	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)
4.16*	Supplemental Trust Indenture, dated as of June 1, 1995, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, creating $250 million aggregate 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
4.17*	Supplemental Trust Indenture, dated as of March 1, 1998, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, creating $150 million aggregate 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
4.18*	Supplemental Trust Indenture, dated as of Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.51
4.19*	Indenture, dated as of July 1, 1999, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to 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)

4.20*	Supplemental Indenture No. 2, dated Aug. 18, 2000, supplemental to the Indenture, dated as of July 1, 1999, among Xcel Energy Inc., NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to Wells Fargo Bank Minnesota, NA), as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.63
4.21*	Supplemental Trust Indenture, dated as of July 1, 2005, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $250 million aggregate principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	4.01
4.22*	Supplemental Trust Indenture, dated as of May 1, 2006, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $400 million aggregate principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	4.01
4.23*	Supplemental Trust Indenture, dated as of June 1, 2007, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $350 million aggregate principal amount of 6.20% First Mortgage Bonds, Series due July 1, 2037	NSP-Minnesota Form 8-K dated June 19, 2007	4.01
4.24*	Supplemental Trust Indenture, dated as of Nov. 1, 2009, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company., NA, as Trustee, creating $300 million aggregate principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	4.01
4.25*	Supplemental Trust Indenture, dated as of Aug. 1, 2010, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as Trustee, creating $250 million aggregate principal amount of 4.85% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	4.01
4.26*	Supplemental Trust Indenture, dated as of Aug. 1, 2012, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as Trustee, creating $500 million aggregate principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	4.01
4.27*	Supplemental Trust Indenture, dated as of May 1, 2013, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $400 million aggregate principal amount of 2.60% First Mortgage Bonds, Series due May 15, 2023	NSP-Minnesota Form 8-K dated May 20, 2013	4.01
4.28*	Supplemental Trust Indenture, dated as of May 1, 2014, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $300 million aggregate principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044	NSP-Minnesota Form 8-K dated May 13, 2014	4.01
4.29*	Supplemental Trust Indenture, dated as of Aug. 1, 2015, by and between NSP-Minnesota and The Bank of New York Mellon Company, N.A., as Trustee, creating $300 million aggregate principal amount of 4.00% First Mortgage Bonds, Series due Aug. 15, 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	4.01
4.30*	Supplemental Trust Indenture, dated as of May 1, 2016, by and between NSP-Minnesota and The Bank of NY Mellon Trust Company, N.A., as Trustee, creating $350 million aggregate principal amount of 3.60% First Mortgage Bonds, Series due May 15, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	4.01
4.31*	Supplemental Trust Indenture, dated as of Sept. 1, 2017, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $600 million aggregate principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	4.01
4.32*	Supplemental Trust Indenture, dated as of Sept. 1, 2019, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $600 million aggregate principal amount of 2.90% First Mortgage Bonds, Series due March 1, 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	4.01
4.33*	Supplemental Indenture, dated as of June 8, 2020, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $700 million aggregate principal amount of 2.60% First Mortgage Bonds, Series due June 1, 2051	NSP-Minnesota 8-K dated June 15, 2020	4.01
4.34*	Supplemental Indenture, dated as of March 1, 2021, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as 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
4.35*	Supplemental Indenture, dated as of May 1, 2022, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $500 million aggregate principal amount of 4.50% First Mortgage Bonds, Series due June 1, 2052	NSP-Minnesota 8-K dated May 9, 2022	4.01
10.27*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.28*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, 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, and Citibank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.02

NSP-Wisconsin			
4.36*	Supplemental and Restated Trust Indenture, dated as of March 1, 1991, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to First Wisconsin Trust Company), as Trustee providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(c)(3)
4.37*	Trust Indenture, dated Sept. 1, 2000, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to Firstar Bank, N.A.), as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	4.01
4.38*	Supplemental Trust Indenture, dated as of Sept. 1, 2008, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $200 million aggregate principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	4.01
4.39*	Supplemental Trust Indenture, dated as of Oct. 1, 2012, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 3.70% First Mortgage Bonds, Series due Oct. 1, 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	4.01
4.40*	Supplemental Trust Indenture, dated as of June 1, 2014, between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 3.30% First Mortgage Bonds, Series due June 15, 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	4.01
4.41*	Supplemental Trust Indenture, dated as of Nov 1, 2017, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 3.75% First Mortgage Bonds, Series due Dec. 1, 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	4.01
4.42*	Supplemental Indenture, dated as of Sept. 1, 2018, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $200 million aggregate principal amount of 4.20% First Mortgage Bonds, Series due Sept. 1, 2048	NSP-Wisconsin Form 8-K dated Sept. 12, 2018	4.01

4.43*	Supplemental Trust Indenture, dated as of May 18, 2020, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $100 million aggregate principal amount of 3.05% First Mortgage Bonds, Series due May 1, 2051	NSP-Wisconsin Form 8-K dated May 26, 2020	4.01
4.44*	Supplemental Indenture dated as of July 19, 2021 between NSP-Wisconsin and U.S. Bank Trust Company, National Association (as successor to 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
4.45*	Supplemental Trust Indenture, dated as of July 15, 2022, by and between NSP-Wisconsin and U.S. Bank Trust Company, National Association, as Trustee, creating $100 million aggregate principal amount of 4.86% First Mortgage Bonds, Series due Sept. 15, 2052	NSP-Wisconsin Form 8-K dated July 15, 2022	4.01
10.29*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.30*	Fourth Amended and Restated Credit Agreement, dated as of Sept. 19, 2022, 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, and Citibank, N.A., MUFG Bank, Ltd. and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.05
PSCo			
4.46*	Indenture, dated as of Oct. 1, 1993, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to 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)
4.47*	Supplemental Indenture No. 17, dated as of Aug. 1, 2007, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $350 million of 6.25% First Mortgage Bonds, Series No. 17 due Sept. 1, 2037	PSCo Form 8-K dated Aug. 8, 2007	4.01
4.48*	Supplemental Indenture No. 18, dated as of Aug. 1, 2008, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 6.50% First Mortgage Bonds, Series No. 19 due Aug. 1, 2038	PSCo Form 8-K dated Aug. 6, 2008	4.01
4.49*	Supplemental Indenture No. 21, dated as of Aug. 1, 2011, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $250 million aggregate principal amount of 4.75% First Mortgage Bonds, Series No. 22 due Aug. 15, 2041	PSCo Form 8-K dated Aug. 9, 2011	4.01
4.50*	Supplemental Indenture No. 22, dated as of Sept. 1, 2012, between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $500 million aggregate principal amount of 3.60% First Mortgage Bonds, Series No. 24 due Sept. 15, 2042	PSCo Form 8-K dated Sept. 11, 2012	4.01
4.51*	Supplemental Indenture No. 23, dated as of March 1, 2013, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $250 million aggregate principal amount of 2.50% First Mortgage Bonds, Series No. 25 due March 15, 2023 and $250 million aggregate principal amount of 3.95% First Mortgage Bonds, Series No. 26 due March 15, 2043	PSCo Form 8-K dated March 26, 2013	4.01
4.52*	Supplemental Indenture No. 24, dated as of March 1, 2014, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 4.30% First Mortgage Bonds, Series No. 27 due March 15, 2044	PSCo Form 8-K dated March 10, 2014	4.01
4.53*	Supplemental Indenture No. 25, dated as of May 1, 2015, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $250 million aggregate principal amount of 2.90% First Mortgage Bonds, Series No. 28 due May 15, 2025	PSCo Form 8-K dated May 12, 2015	4.01
4.54*	Supplemental Indenture No. 26, dated as of June 1, 2016, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $250 million aggregate principal amount of 3.55% First Mortgage Bonds, Series No. 29 due June 15, 2046	PSCo Form 8-K dated June 13, 2016	4.01
4.55*	Supplemental Indenture No. 27, dated as of June 1, 2017, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $400 million aggregate principal amount of 3.80% First Mortgage Bonds, Series No. 30 due June 15, 2047	PSCo Form 8-K dated June 19, 2017	4.01
4.56*	Supplemental Indenture No. 28, dated as of June 1, 2018, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $350 million aggregate principal amount of 3.70% First Mortgage Bonds, Series No. 31 due June 15, 2028, and $350 million aggregate principal amount of 4.10% First Mortgage Bonds, Series No. 32 due June 15, 2048	PSCo Form 8-K dated June 21, 2018	4.01
4.57*	Supplemental Indenture No. 29, dated as of March 1, 2019, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $400 million aggregate principal amount of 4.05% First Mortgage Bonds, Series No. 33 due Sept. 15, 2049	PSCo Form 8-K dated March 13, 2019	4.01
4.58*	Supplemental Indenture No. 30, dated as of Aug. 1, 2019, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $550 million aggregate principal amount of 3.20% First Mortgage Bonds, Series No. 34 due March 1, 2050	PSCo Form 8-K dated August 13, 2019	4.01
4.59*	Supplemental Indenture No. 31, dated as of May 1, 2020, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $375 million aggregate principal amount of 2.70% First Mortgage Bonds, Series No. 35 due Jan. 15, 2051 and $375 million aggregate principal amount of 1.90% First Mortgage Bonds, Series No. 36 due Jan. 15, 2031	PSCo Form 8-K dated May 15, 2020	4.01
4.60*	Supplemental Indenture No. 32, dated as of February 1, 2021, by and between PSCo and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $750 million aggregate principal amount of 1.875% First Mortgage Bonds, Series No. 37 due June 15, 2031	PSCo Form 8-K dated March 1, 2021	4.01
4.61*	Supplemental Indenture No. 33, dated as of May 1, 2022, by and between PSCo and U.S. Bank Trust Company, National Association, as Trustee, creating $300 million aggregate principal amount of 4.10% First Mortgage Bonds, Series No. 38 due June 1, 2032 and $400 million aggregate principal amount of 4.50% First Mortgage Bonds, Series No. 39 due June 1, 2052	PSCo Form 8-K dated May 17, 2022	4.01
10.31*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	99.02
10.32*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, 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, and Citibank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.03
SPS			

4.62*	Indenture, dated as of Feb. 1, 1999, by and between SPS and The Chase Manhattan Bank, as Trustee	SPS Form 8-K dated Feb. 25, 1999	99.2
4.63*	Third Supplemental Indenture, dated as of Oct. 1, 2003, by and between SPS and JPMorgan Chase Bank (as successor to The Chase Manhattan Bank), as Trustee, creating $100 million aggregate principal amount of Series C Notes, 6% due Oct. 1, 2033 and Series D Notes, 6% due Oct. 1, 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	4.04
4.64*	Fourth Supplemental Indenture, dated as of Oct. 1, 2006, by and between SPS and The Bank of New York (as successor to The Chase Manhattan Bank), as Trustee, creating $250 million aggregate principal amount of Series F Notes, 6% due Oct. 1, 2036	SPS Form 8-K dated Oct. 3, 2006	4.01
4.65*	Indenture, dated as of Aug. 1, 2011, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee	SPS Form 8-K dated Aug. 10, 2011	4.01
4.66*	Supplemental Indenture No. 1, dated as of Aug. 3, 2011, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $200 million aggregate principal amount of 4.50% First Mortgage Bonds, Series No. 1 due Aug. 15, 2041	SPS Form 8-K dated Aug. 10, 2011	4.02
4.67*	Supplemental Indenture No. 3, dated as of June 1, 2014, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $150 million aggregate principal amount of 3.30% First Mortgage Bonds, Series No. 3 due June 15, 2024	SPS Form 8-K dated June 9, 2014	4.02
4.68*	Supplemental Indenture No. 4, dated as of Aug. 1, 2016, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 3.40% First Mortgage Bonds, Series No. 4 due Aug. 15, 2046	SPS Form 8-K dated Aug. 12, 2016	4.02
4.69*	Supplemental Indenture No. 5, dated as of Aug. 1, 2017, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $450 million aggregate principal amount of 3.70% First Mortgage Bonds, Series No. 5 due Aug. 15 2047	SPS Form 8-K dated Aug 9. 2017	4.02
4.70*	Supplemental Indenture No. 6, dated as of Oct. 1, 2018, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 4.40% First Mortgage Bonds, Series No. 6 due Nov. 15, 2048	SPS Form 8-K dated Nov. 5, 2018	4.02
4.71*	Supplemental Indenture No. 7, dated as of June 1, 2019, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $300 million aggregate principal amount of 3.75% First Mortgage Bonds, Series No. 7 due June 15, 2049	SPS Form 8-K dated June 18, 2019	4.02
4.72*	Supplemental Indenture No. 8, dated as of May 1, 2020, by and between SPS and U.S. Bank Trust Company, National Association (as successor to U.S. Bank National Association), as Trustee, creating $600 million aggregate principal amount of 3.15% First Mortgage Bonds, Series No. 8 due May 1, 2050	SPS Form 8-K dated May 18, 2020	4.02
4.73*	Supplemental Indenture No. 9, dated as of May 1, 2022, by and between SPS and U.S. Bank Trust Company, National Association, as Trustee, creating $200 million aggregate principal amount of 5.15% First Mortgage Bonds, Series No. 9 due June 1, 2052	SPS Form 8-K dated May 31, 2022	4.02
10.33*	Fourth Amended and Restated Credit Agreement, dated as of Sept. 19, 2022, 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, and Citibank, N.A., MUFG Bank, Ltd. and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	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		
	2022	2021	2020
Income			
Equity earnings of subsidiaries	$ 1,905	$ 1,744	$ 1,646
Total income	1,905	1,744	1,646
Expenses and other deductions			
Operating expenses	19	21	43
Other (income) expenses	(2)	3	(4)
Interest charges and financing costs	206	173	198
Total expenses and other deductions	223	197	237
Income before income taxes	1,682	1,547	1,409
Income tax benefit	(54)	(50)	(64)
Net income	$ 1,736	$ 1,597	$ 1,473
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $ 1, $1 and $1, respectively	$ 9	$ 8	$ 5
Derivative instruments, net of tax of $3, $(1) and $(7), respectively	21	10	(5)
Other comprehensive income	30	18	—
Comprehensive income	$ 1,766	$ 1,615	$ 1,473
Weighted average common shares outstanding:			
Basic	547	539	527
Diluted	547	540	528
Earnings per average common share:			
Basic	$ 3.18	$ 2.96	$ 2.79
Diluted	3.17	2.96	2.79

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2022	2021	2020
Operating activities			
Net cash provided by operating activities	$ 1,340	$ 1,147	$ 2,377
Investing activities			
Capital contributions to subsidiaries	(921)	(1,661)	(2,553)
Net return (investments) in the utility money pool	—	57	(18)
Other, net	—	—	(1)
Net cash used in investing activities	(921)	(1,604)	(2,572)
Financing activities			
Proceeds (repayment of) from short-term borrowings, net	(407)	638	(500)
Proceeds from issuance of long-term debt	694	791	1,089
Repayment of long-term debt	—	(400)	(300)
Proceeds from issuance of common stock	322	366	727
Repurchase of common stock	—	—	(4)
Dividends paid	(1,012)	(935)	(856)
Other	(16)	(16)	(17)
Net cash provided by financing activities	(419)	444	139
Net change in cash, cash equivalents, and restricted cash	—	(13)	(56)
Cash, cash equivalents and restricted cash at beginning of period	1	14	70
Cash, cash equivalents and restricted cash at end of period	$ 1	$ 1	$ 14

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2022	2021
Assets		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable from subsidiaries	443	430
Derivative instruments	1	—
Other current assets	7	6
Total current assets	452	437
Investment in subsidiaries	22,597	21,167
Other assets	(7)	71
Total other assets	22,590	21,238
Total assets	$ 23,042	$ 21,675
Liabilities and Equity		
Current portion of long-term debt	500	—
Dividends payable	268	249
Short-term debt	231	638
Other current liabilities	17	29
Total current liabilities	1,016	916
Other liabilities	13	10
Total other liabilities	13	10
Commitments and contingencies		
Capitalization		
Long-term debt	5,338	5,137
Common stockholders' equity	16,675	15,612
Total capitalization	22,013	20,749
Total liabilities and equity	$ 23,042	$ 21,675

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, 2022 and 2021, 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, 2022:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of loan for Hiawatha Collegiate High School [(a)]	Xcel Energy Inc.	$ 1	—	(b)
Guarantee of Capital Services purchase contract for solar generating equipment. [(c)]	Xcel Energy Inc.	98	(d)	(b)
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries [(e)]	Xcel Energy Inc.	61	(f)	(g)

(a) The guarantee expires the earlier of 2024 or full repayment of the loan.
(b) Nonperformance and/or nonpayment.
(c) The guarantee expires the earlier of termination or payment of all obligations under the purchase contract.
(d) Given that the manufacturing of solar generating equipment has not yet commenced, related exposure to the payment obligations of Capital Services at Dec. 31, 2022 is immaterial.
(e) 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.
(f) 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.
(g) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.

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)	2022	2021
NSP-Minnesota	$ 82	$ 104
NSP-Wisconsin	17	25
PSCo	111	91
SPS	61	58
Xcel Energy Services Inc.	145	125
Other subsidiaries of Xcel Energy Inc.	27	27
	$ 443	$ 430

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $1,503 million, $1,344 million and $2,527 million for the years ended Dec. 31, 2022, 2021 and 2020, 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, 2022
Loan outstanding at period end	$ —
Average loan outstanding	1
Maximum loan outstanding	50
Weighted average interest rate, computed on a daily basis	0.01 %
Weighted average interest rate at end of period	N/A
Money pool interest income	$ —

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Year Ended Dec. 31, 2020
Loan outstanding at period end	$ —	$ —	$ 57
Average loan outstanding	10	16	104
Maximum loan outstanding	204	439	350
Weighted average interest rate, computed on a daily basis	0.73 %	0.08 %	0.60 %
Weighted average interest rate at end of period	N/A	N/A	0.07
Money pool interest income	$ —	$ —	$ 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)	2022	2021	2020	2022	2021	2020
Balance at Jan. 1	$ 106	$ 79	$ 55	$ 64	$ 64	$ 67
Additions charged to costs and expenses	73	60	60	6	5	6
Additions charged to other accounts	26 (a)	14 (a)	12 (a)	—	—	—
Deductions from reserves	(83) (b)	(47) (b)	(48) (b)	(8) (c)	(5) (c)	(9) (d)
Balance at Dec. 31	$ 122	$ 106	$ 79	$ 62	$ 64	$ 64

(a) Recovery of amounts previously written-off.
(b) Deductions related primarily to bad debt write-offs.
(c) Primarily reductions to valuation allowances due to additional NOLs and tax credits forecasted to be used prior to expiration.
(d) 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.

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, 2023	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 Accounting Officer and Principal Financial Officer)
*	Megan Burkhart	Director
*	Lynn Casey	Director
*	Netha 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
*	Kim Williams	Director
*	Daniel Yohannes	Director
*By:	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Attorney-in-Fact

SHAREHOLDER INFORMATION

Headquarters
414 Nicollet Mall, Minneapolis, MN 55401

Website
xcelenergy.com

Stock Transfer Agent
EQ Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
Telephone: 877-778-6786, toll free

Reports Available Online
Financial reports, including filings with the Securities and Exchange Commission and other investor materials, are available online at xcelenergy.com; click on Investors. Other information about Xcel Energy, including our Code of Conduct, Guidelines on Corporate Governance, Sustainability Report and Committee Charters, is also available at xcelenergy.com.

Stock Exchange Listings and Ticker Symbol
Common stock is listed on the Nasdaq Global Select Market (Nasdaq) under the ticker symbol XEL. In newspaper listings, it may appear as XcelEngy.

Investor Relations
Website: investors.xcelenergy.com or contact Paul Johnson, Vice President, Treasurer & Investor Relations, at 612-215-4535.

Shareholder Services
Website: investors.xcelenergy.com or contact Darin Norman, Consultant, Investor Relations, at 612-337-2310 or email darin.norman@xcelenergy.com.

Corporate Governance
Xcel Energy has filed with the Securities and Exchange Commission certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2022.

To contact the Board of Directors, send an email to boardofdirectors@xcelenergy.com.

You also may direct questions to the Corporate Secretary's department at corporatesecretary@xcelenergy.com.

FISCAL AGENTS

XCEL ENERGY INC.

Transfer Agent, Registrar, Dividend Distribution, Common Stock
EQ Shareowner Services,
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120

Trustee–Bonds
Computershare Corporate Trust
MAC 9300-070
600 South 4th Street
Minneapolis, MN 55415

Xcel Energy®

Northern States Power Company
Gas Utility - State of Minnesota
DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR

Definition: The incremental amount of gross revenue required to generate an additional dollar of operating income. Gross earnings fees included.

Let: GR = Gross Revenue Conversion Factor
T= Federal and Minnesota Income Tax

Formula for Gross Revenue Conversion Factor

$$GR = \frac{1}{1 - T}$$

Gross Revenue Conversion Factor:

$$GR = \frac{1}{1 - 0.287420}$$

$$GR = 1.403351$$