Northern States Power Company
Gas Utility - Minnesota

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES
Test Year Ending December 31, 2022
Revenue by Rate Schedule

Docket No. G002/GR-21-678
Exhibit___(MMT-1), Schedule 5

Residential Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	5,331,144		$9.00	$47,980,296	$11.00	$58,642,584	$10,662,288	
Distribution Charge		389,299,108	$0.175996	$68,515,086	$0.285785	$111,255,845	$42,740,759	
CIP/SEP/GUIC TY Adj		389,299,108	$0.067050	$26,102,622	$0.000000	$0	-$26,102,622	
Margin Subtotal				$142,598,004		$169,898,429	$27,300,425	19.1%
Gas Supply Charge								
April through October		94,647,687	$0.397729	$37,644,130	$0.397729	$37,644,130	$0	
November through March		294,651,421	$0.463431	$136,550,603	$0.463431	$136,550,603	$0	
Gas Supply Subtotal		389,299,108		$174,194,733		$174,194,733	$0	0.0%
Average Customers	444,262		**Total**	$316,792,737		$344,093,162	$27,300,425	8.6%

Small Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	297,960		$25.00	$7,448,999	$30.00	$8,938,798	$1,489,799	
Distribution Charge		51,420,746	$0.116732	$6,002,447	$0.168025	$8,639,971	$2,637,524	
CIP/SEP/GUIC TY Adj		51,420,746	$0.044995	$2,313,692	$0.000000	$0	-$2,313,692	
CIP Neutrality exemption		11,000	-$0.018662	-$205	$0.000000	$0		
Cip base exemption		11,000	-$0.005240	-$58	-$0.023902	-$263		
Margin Subtotal				$15,764,875		$17,578,506	$1,813,631	11.5%
Gas Supply Charge								
April through October		10,838,776	$0.396154	$4,293,824	$0.396154	$4,293,824	$0	
November through March		40,581,971	$0.461856	$18,743,027	$0.461856	$18,743,027	$0	
Gas Supply Subtotal		51,420,746		$23,036,851		$23,036,851	$0	0.0%
Average Customers	24,830		**Total**	$38,801,726		$40,615,357	$1,813,631	4.7%

Large Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	135,146		$50.00	$6,757,300	$70.00	$9,460,220	$2,702,920	
Distribution Charge		178,596,136	$0.116582	$20,821,095	$0.167725	$29,955,037	$9,133,942	
CIP/SEP/GUIC TY Adj		178,596,136	$0.044995	$8,035,987	$0.000000	$0	-$8,035,987	
CIP Neutrality exemption		77,167	-$0.018662	-$1,440	$0.000000	$0	$1,440	
Cip base exemption		77,167	-$0.005240	-$404	-$0.023902	-$1,844	-$1,440	
Margin Subtotal				$35,612,538		$39,413,413	$3,800,875	10.7%
Gas Supply Charge								
April through October		47,962,652	$0.396154	$19,000,597	$0.396154	$19,000,597	$0	
November through March		130,633,484	$0.461856	$60,333,858	$0.461856	$60,333,858	$0	
Gas Supply Subtotal		178,596,136		$79,334,455		$79,334,455	$0	0.0%
Average Customers	11,262		**Total**	$114,946,993		$118,747,868	$3,800,875	3.3%

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Small & Large Commercial Demand Billed

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,680		$275.00	$462,000	$275.00	$465,600	$3,600	
Discount				-$18,000		-$18,000		
Distribution Charges								
Distribution Demand Charge		3,395,255	$0.809470	$2,748,357	$0.882000	$2,994,615	$246,258	
Distribution Commodity Charge		29,905,854	$0.044978	$1,345,105	$0.085138	$2,546,125	$1,201,020	
CIP/SEP/GUIC TY Adj		29,905,854	$0.038902	$1,163,392	$0.000000	$0	-$1,163,392	
CIP Neutrality exemption		289,589	-$0.018662	-$5,404	$0.000000	$0	$5,404	
Cip base exemption		289,589	-$0.005240	-$1,517	-$0.023902	-$6,922	-$5,405	
Margin Subtotal				$5,693,933		$5,981,418	$287,485	5.0%
Gas Supply Charges								
Gas Supply Demand Charge		3,395,255	$0.725628	$2,463,692	$0.725628	$2,463,692	$0	
Gas Supply Commodity Charge		29,905,854	$0.327832	$9,804,096	$0.327832	$9,804,096	$0	
Gas Supply Subtotal				$12,267,788		$12,267,788	$0	0.0%
Average Customers	128		**Total**	$17,961,721		$18,249,206	$287,485	1.6%

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Small Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	2,486		$145.00	$360,470	$150.00	$372,900	$12,430	
Distribution Charge		16,409,131	$0.091214	$1,496,742	$0.144125	$2,364,966	$868,224	
CIP/SEP/GUIC TY Adj		16,409,131	$0.035961	$590,085	$0.000000	$0	-$590,085	
Margin Subtotal				$2,447,297		$2,737,866	$290,569	11.9%
Gas Supply Charge		16,409,131	$0.336877	$5,527,859	$0.336877	$5,527,859	$0	0.0%
Average Customers	207		**Total**	$7,975,156		$8,265,725	$290,569	3.6%

Medium & Large Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,092		$300.00	$327,600	$300.00	$327,600	$0	
Discount				-89,279		9,000	$98,279	
Distribution Charge		78,279,409	$0.044978	$3,520,851	$0.083431	$6,530,959	$3,010,108	
CIP/SEP/GUIC TY Adj		78,279,409	$0.035961	$2,814,990	$0.000000	$0	-$2,814,990	
CIP Neutrality exemption		531,035	-$0.018662	-$9,910	$0.000000	$0	$9,910	
Cip base exemption		531,035	-$0.005240	-$2,783	-$0.023902	-$12,693	-$9,910	
Margin Subtotal				$6,561,469		$6,854,866	$293,397	4.5%
Gas Supply Charge		78,279,409	$0.327193	$25,612,469	$0.327193	$25,612,469	$0	0.0%
Average Customers	91		**Total**	$32,173,938		$32,467,335	$293,397	0.9%

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Transportation

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	312		$325.00	$101,400	$325.00	$101,400	$0	
Discount				-3,300		-$3,300		
Distribution Charges								
Distribution Demand Charge		431,778	$0.809470	$349,511	$0.882000	$380,828	$31,317	
Distribution Commodity Charge		133,818,194	$0.027898	$3,733,196	$0.062239	$5,890,821	$2,157,625	
CIP/SEP/GUIC TY Adj		133,818,194	$0.022413	$1,715,432	$0.000000	$511,293	-$1,204,139	
CIP Neutrality exemption		(27,111,106)	$0.018662	-$505,948	$0.018662	-$505,947	$1	
Cip base exemption		(27,111,106)	$0.005240	-$142,062	$0.005240	-$142,062	$0	
Average Customers	26		**Total**	$5,248,229		$6,233,033	$984,804	18.8%

Generation (summary of 6 customers on 4 retail rates)

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	84			$24,300		$24,300	$0	0.0%
Distribution Charges		233,390,970		$6,129,687		$6,239,298	$109,611	1.8%
CIP/SEP/GUIC TY Adj		233,390,970	$0.015190	$880,115	$0.004890	$871,475	($8,640)	
Margin Subtotal				$7,034,102		$7,135,073		
Gas Supply Charge				$81,250		$81,250	$0	0.0%
Average Customers	7		**Total**	$7,115,352		$7,216,323	$100,971	1.4%

Class Cost of Service Study ($000); Test Year 2022

SUMMARY

Rate Base		Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production	50,807	26,701	15,757	1,631	0	207	6,510
2	Storage	66,050	34,712	20,485	2,121	0	270	8,463
3	Transmission	121,439	48,459	28,599	3,001	3,193	4,712	33,475
4	Distribution	1,364,436	1,076,927	209,911	11,039	13,665	15,020	37,872
5	General	185,633	137,458	31,823	2,061	1,953	2,341	9,998
6	Common	0	0	0	0	0	0	0
7	**Total Plant In Service**	**1,788,364**	**1,324,258**	**306,575**	**19,854**	**18,811**	**22,550**	**96,318**
8	Production	10,510	5,523	3,260	337	0	43	1,347
9	Storage	43,072	22,636	13,358	1,383	0	176	5,519
10	Transmission	28,585	11,426	6,743	708	753	1,111	7,844
11	Distribution	523,033	419,153	81,127	3,488	4,773	4,190	10,303
12	General	86,632	64,150	14,851	962	911	1,092	4,666
13	Common	0	0	0	0	0	0	0
14	**Total Depreciation Reserve**	**691,832**	**522,888**	**119,339**	**6,878**	**6,437**	**6,612**	**29,679**
15	**Net Plant**	**1,096,532**	**801,369**	**187,236**	**12,976**	**12,374**	**15,938**	**66,639**
16	**Deductions** (Accum Def Inc Tax)	**202,226**	**150,609**	**33,343**	**2,027**	**2,325**	**2,710**	**11,212**
17	**Additions**	**40,142**	**25,967**	**5,760**	**438**	**559**	**2,309**	**5,108**
18	**Rate Base**	**934,448**	**676,727**	**159,654**	**11,387**	**10,608**	**15,537**	**60,536**

Income Statement		Minn	Res	Com	Demand	Interrupt	Tran	Gener
19	**Present Retail Revenue**	**541,016**	**316,793**	**153,749**	**17,962**	**40,149**	**5,248**	**7,115**
20	**Present Other Oper Rev**	**4,908**	**3,021**	**1,085**	**108**	**72**	**111**	**511**
21	**Present Total Operating Rev**	**545,924**	**319,814**	**154,834**	**18,069**	**40,221**	**5,360**	**7,626**
	Operating & Maint Expenses							
22	Purchased Gas Expense	320,055	174,195	102,371	12,268	31,140	0	81
23	Other Purch Gas Exp	0	0	0	0	0	0	0
24	Other Production	5,659	2,865	1,691	187	180	90	647
25	Transmission	2,419	1,171	691	73	77	114	294
26	Distribution	39,105	30,992	5,346	325	410	559	1,473
27	Customer Accounting	14,038	12,533	1,126	161	196	17	5
28	Customer Service and Information	964	704	215	13	28	2	1
29	Administrative and General	21,869	16,099	3,819	314	481	276	880
30	Amortizations; Sales Expense	19,110	9,589	5,596	718	2,273	915	19
31	**Total Operating & Maint Exp**	**423,219**	**248,147**	**120,854**	**14,058**	**34,786**	**1,973**	**3,400**
32	Book Depreciation	53,130	39,575	9,326	586	511	572	2,561
33	Taxes Other Than Income Taxes	22,205	11,518	5,902	603	604	886	2,691
34	Prov For Deferred Inc Taxes	2,957	1,683	715	72	42	63	384
35	Net Investment Tax Credit	-107	-80	-17	-1	-1	-2	-5
36	**Total Operating Expense**	**501,405**	**300,843**	**136,780**	**15,318**	**35,941**	**3,492**	**9,031**
37	State and Federal Income Taxes	3,891	-586	3,515	649	1,119	365	-1,171
38	**Total Expense**	**505,296**	**300,257**	**140,294**	**15,967**	**37,060**	**3,857**	**7,860**
39	AFUDC (Rev Credit)	3,693	2,633	681	56	39	56	228
40	**Total Operating Income**	**44,321**	**22,190**	**15,221**	**2,158**	**3,200**	**1,559**	**-6**
41	**Rate Base**	**934,448**	**676,727**	**159,654**	**11,387**	**10,608**	**15,537**	**60,536**
42	**Present Return on Rate Base**	**4.74%**	**3.28%**	**9.53%**	**18.95%**	**30.16%**	**10.03%**	**-0.01%**
43	**Present Return on Common Equity**	**5.32%**	**2.53%**	**14.45%**	**32.38%**	**53.74%**	**15.40%**	**-3.73%**
44	**Required Return on Rate Base**	**7.46%**	**7.46%**	**7.46%**	**7.46%**	**7.46%**	**7.46%**	**7.46%**
45	**Required Operating Income**	**69,710**	**50,484**	**11,910**	**849**	**791**	**1,159**	**4,516**
46	**Income Deficiency**	**25,388**	**28,294**	**-3,311**	**-1,308**	**-2,408**	**-400**	**4,522**
47	**Revenue Deficiency**	**35,629**	**39,954**	**-4,802**	**-1,861**	**-3,437**	**-567**	**6,342**
48	**Deficiency / Pres Retail Revenue**	**6.59%**	**12.61%**	**-3.12%**	**-10.36%**	**-8.56%**	**-10.80%**	**89.13%**

Class Cost of Service Study ($000); Test Year 2022

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
Equal Return vs Present								
	Operating Revenue Requirement							
1	Return On Rate Base	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%
2	Equalized Total Retail Rev	576,645	356,746	148,947	16,101	36,712	4,681	13,457
3	Present Total Retail Revenue	541,016	316,793	153,749	17,962	40,149	5,248	7,115
4	Revenue Deficiency	35,629	39,954	-4,802	-1,861	-3,437	-567	6,342
5	Deficiency / Pres Total Retail Rev	6.59%	12.61%	-3.12%	-10.36%	-8.56%	-10.80%	89.13%
	Internal Retail Revenue Reqt							
6	Customer Retail Revenue Requirement	144,483	128,697	14,816	329	575	53	13
7	Average Monthly Customers	480,825	444,262	36,092	140	298	26	7
8	Revenue Requirement $ / Mo / Cust	25.04	24.14	34.21	196.08	160.57	171.01	150.80
9	Capacity Retail Revenue Requirement	86,922	41,637	24,827	2,619	2,199	3,193	12,447
10	Annual Dkt Sales	111,111,955	38,929,911	23,001,688	2,990,585	9,468,854	13,381,819	23,339,097
11	Revenue Requirement $ / Dkt	0.78	1.07	1.08	0.88	0.23	0.24	0.53
	Capacity - Sub Classification							
12	Capacity - Base Revenue Requirement	23,658	8,641	5,159	676	2,199	2,985	3,998
13	Capacity - Seasonal Revenue Requirement	44,640	23,254	13,851	1,336	0	132	6,067
14	Peak Shaving Revenue Requirement	18,624	9,741	5,818	606	0	76	2,382
15	Base Rev Requirement $ / Dkt	0.21	0.22	0.22	0.23	0.23	0.22	0.17
16	Seasonal Rev Requirement $ / Dkt	0.40	0.60	0.60	0.45	0.00	0.01	0.26
17	Peak Shave Rev Requirement $ / Dkt	0.17	0.25	0.25	0.20	0.00	0.01	0.10
18	Energy Retail Revenue Requirement	24,428	11,519	6,876	885	2,798	1,435	917
19	Revenue Requirement $ / Dkt	0.22	0.30	0.30	0.30	0.30	0.11	0.04
20	Total Internal Retail Revenue Requirement	255,833	181,852	46,519	3,833	5,572	4,681	13,376
21	Revenue Requirement $ / Dkt	2.30	4.67	2.02	1.28	0.59	0.35	0.57
22	Revenue Requirement $ / Mo / Cust	44.34	34.11	107.41	2,281.42	1,557.17	15,003.68	159,238.14
	External Retail Revenue Reqt							
23	Capacity Revenue Requirement	66,581	40,418	23,692	2,464	0	0	9
24	Energy Revenue Requirement	253,474	133,777	78,680	9,804	31,140	0	73
25	Total External Revenue Requirement	320,055	174,195	102,371	12,268	31,140	0	81
26	Cap Revenue Requirement $ / Dkt	0.60	1.04	1.03	0.82	0.00	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.28	3.44	3.42	3.28	3.29	0.00	0.00
28	Tot Revenue Requirement $ / Dkt	2.88	4.47	4.45	4.10	3.29	0.00	0.00
	Total Retail Revenue Reqt							
29	Customer Revenue Requirement	144,483	128,697	14,816	329	575	53	13
30	Capacity Revenue Requirement	153,503	82,054	48,519	5,082	2,199	3,193	12,455
31	Energy Revenue Requirement	277,902	145,296	85,556	10,689	33,938	1,435	989
32	Total Revenue Requirement	575,888	356,047	148,890	16,101	36,712	4,681	13,457
33	Customer Revenue Reqt $ / Dkt	1.30	3.31	0.64	0.11	0.06	0.00	0.00
34	Demand Revenue Reqt $ / Dkt	1.38	2.11	2.11	1.70	0.23	0.24	0.53
35	Energy Revenue Reqt $ / Dkt	2.50	3.73	3.72	3.57	3.58	0.11	0.04
36	Total Revenue Reqt $ / Dkt	5.18	9.15	6.47	5.38	3.88	0.35	0.58
Proposed Return vs Present								
37	Proposed Total Retail Revenue	576,645	344,793	159,419	18,249	40,734	6,233	7,216
38	Revenue Deficiency	35,629	28,000	5,671	288	584	985	101
39	Deficiency / Pres Total Oper Revenue	6.59%	8.84%	3.69%	1.60%	1.46%	18.77%	1.42%
Proposed Return vs Equal								
40	Revenue Difference	0	-11,954	10,473	2,149	4,021	1,552	-6,241
41	Difference / Tot Equal Revenue"	0.00%	-3.35%	7.03%	13.34%	10.95%	33.15%	-46.38%

Class Cost of Service Study ($000); Test Year 2022

RATE BASE

	Plant in Service	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	50,807	26,701	15,757	1,631	0	207	6,510
2	**Storage Plant (LNG)**	Design Day	66,050	34,712	20,485	2,121	0	270	8,463
3	Transmission - Average C	Average and Peak	100,132	48,459	28,599	3,001	3,193	4,712	12,168
4	Transmission - Direct Ass	Direct Assign	21,306	0	0	0	0	0	21,306
5	**Transmission Plant**		121,439	48,459	28,599	3,001	3,193	4,712	33,475
	Distribution Plant								
6	Regulator Stations	Average and Peak	605	293	173	18	19	28	74
7	Mains - Minimum System	Modified Customer	540,379	499,289	40,563	157	335	29	6
8	Mains - Average Capacity	Modified Sales W/	107,219	40,691	24,042	3,126	9,897	13,987	15,475
9	Mains - Excess Capacity	Excess Design Da	203,129	109,501	64,597	6,175	0	617	22,239
10	Mains - Total		850,726	649,481	129,202	9,459	10,232	14,633	37,720
11	Services	Service Study	355,443	301,263	52,006	579	1,452	120	22
12	Meters	Meter & Regul Stu	128,966	102,977	23,338	805	1,605	195	46
13	House Regulators	Meter & Regul Stu	28,695	22,913	5,193	179	357	43	10
14	Total Distribution Plant		1,364,436	1,076,927	209,911	11,039	13,665	15,020	37,872
15	**General Plant**	Prod-Stor-Tran-Dis	185,633	137,458	31,823	2,061	1,953	2,341	9,998
16	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
17	**Gas Plant in Service**		**1,788,364**	**1,324,258**	**306,575**	**19,854**	**18,811**	**22,550**	**96,318**
	Accum Depr Reserve	**Allocator**							
18	**Production Plant (LPG)**	Design Day	10,510	5,523	3,260	337	0	43	1,347
19	**Storage Plant (LNG)**	Design Day	43,072	22,636	13,358	1,383	0	176	5,519
20	Transmission - Average C	Average and Peak	23,610	11,426	6,743	708	753	1,111	2,869
21	Transmission - Direct Ass	Direct Assign	4,975	0	0	0	0	0	4,975
22	**Transmission Plant**		28,585	11,426	6,743	708	753	1,111	7,844
	Distribution Plant								
23	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
24	Mains	Mains, Overall	231,316	176,597	35,130	2,572	2,782	3,979	10,256
25	Services	Service Study	196,076	166,189	28,689	319	801	66	12
26	Meters	Meter & Regul Stu	78,803	62,923	14,260	492	981	119	28
27	House Regulators	Meter & Regul Stu	16,838	13,445	3,047	105	210	25	6
28	Total Distribution Plant		523,033	419,153	81,127	3,488	4,773	4,190	10,303
29	**General Plant**	Prod-Stor-Tran-Dis	86,632	64,150	14,851	962	911	1,092	4,666
30	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
31	**Total Accum Depr**		**691,832**	**522,888**	**119,339**	**6,878**	**6,437**	**6,612**	**29,679**
32	**Net Plant**		**1,096,532**	**801,369**	**187,236**	**12,976**	**12,374**	**15,938**	**66,639**
	Subtractions to Net Plant								
	Accum Deferred Inc Tax	**Allocator**							
33	**Production Plant (LPG)**	Design Day	1,401	736	434	45	0	6	179
34	**Storage Plant (LNG)**	Design Day	528	278	164	17	0	2	68
35	Transmission - Average C	Average and Peak	16,447	7,960	4,698	493	525	774	1,999
36	Transmission - Direct Ass	Direct Assign	3,781	0	0	0	0	0	3,781
37	**Transmission Plant**		20,228	7,960	4,698	493	525	774	5,780
	Distribution Plant								
38	Regulator Stations	Average and Peak	9	5	3	0	0	0	1
39	Mains	Mains, Overall	97,772	74,644	14,849	1,087	1,176	1,682	4,335
40	Services	Service Study	44,231	37,489	6,472	72	181	15	3
41	Meters	Meter & Regul Stu	19,782	15,796	3,580	123	246	30	7
42	House Regulators	Meter & Regul Stu	2,591	2,069	469	16	32	4	1
43	Total Distribution Plant		164,386	130,002	25,372	1,299	1,635	1,731	4,347
44	**General Plant**	Prod-Stor-Tran-Dis	15,159	11,225	2,599	168	159	191	816
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	524	409	76	5	6	7	22
48	**Total Subtractions**		**202,226**	**150,609**	**33,343**	**2,027**	**2,325**	**2,710**	**11,212**

Class Cost of Service Study ($000); Test Year 2022 RATE BASE

	Additions to Net Plant								
	CWIP	**Allocator**	**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
1	Production Plant (LPG)	Design Day	336	176	104	11	0	1	43
2	Storage Plant (LNG)	Design Day	2,529	1,329	784	81	0	10	324
3	Transmission - Average C	Average and Peak	1,066	516	304	32	34	50	130
4	Transmission - Direct Ass	Direct Assignment	0	0	0	0	0	0	0
5	Transmission Plant		1,066	516	304	32	34	50	130
6	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
7	Mains	Mains Overall	17,638	13,466	2,679	196	212	303	782
8	Services	Service Study	0	0	0	0	0	0	0
9	Meters	Meter & Regul Stu	0	0	0	0	0	0	0
10	House Regulators	Meter & Regul Stu	25	20	5	0	0	0	0
11	General & Common Plant	Prod-Stor-Tran-Dis	6,032	4,467	1,034	67	63	76	325
12	Total CWIP		27,627	19,975	4,910	387	310	441	1,604
13	**Materials & Supplies**	Tran & Distrib	1,249	946	200	12	14	17	60
	Gas In Storage								
14	Total Gas in Storage	Sales, W/ Transp	14,823	5,194	3,069	399	1,263	1,785	3,114
15	**Non-Plant Assets & Liab**	Labor	7,928	6,185	1,156	78	85	98	326
	Miscellaneous	**Allocator**							
16	Prepay: Insurance	Tran & Distrib	0	0	0	0	0	0	0
17	Prepay: Miscellaneous	Tran & Distrib	2,262	1,713	363	21	26	30	109
18	Fuel	Sales, W/o Transp	0	0	0	0	0	0	0
19	Total Miscellaneous		2,262	1,713	363	21	26	30	109
	Working Cash								
20	Total Working Cash	Modified O&M Exp	-13,747	-8,045	-3,938	-459	-1,139	-62	-104
21	**Total Additions**		**40,142**	**25,967**	**5,760**	**438**	**559**	**2,309**	**5,108**
22	**Total Rate Base**		**934,448**	**676,727**	**159,654**	**11,387**	**10,608**	**15,537**	**60,536**
23	**Common Rate Base (@ 52.50%)**		**490,585**	**355,282**	**83,818**	**5,978**	**5,569**	**8,157**	**31,781**
24	Customer Component		562,252	502,969	57,090	631	1,392	140	30
25	Demand Component		366,051	173,172	102,205	10,695	9,027	13,611	57,341
26	Energy Component		6,145	586	358	61	189	1,786	3,165

Class Cost of Service Study ($000); Test Year 2022

			Minn	Res	Com	Demand	Interrupt	Tran	Gener
	Operating Revenue (Cal Month)								
	Retail Revenue	**Allocator**	**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
1a	**Present Retail Rev**	Direct Assign	**541,016**	**316,793**	**153,749**	**17,962**	**40,149**	**5,248**	**7,115**
1b	**Proposed Retail Rev**	Direct Assign	**575,888**	**344,093**	**159,363**	**18,249**	**40,733**	**6,233**	**7,216**
2	**Retail Rev Increase**		**34,872**	**27,300**	**5,615**	**287**	**584**	**985**	**101**
	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 Payment Stuc	1,021	951	68	1	1	0	0
4	Connection Charges	Customers	361	334	27	0	0	0	0
5	Return Check Charges	Customers	42	39	3	0	0	0	0
6	Connect Smart	Customers	24	22	2	0	0	0	0
7	Interchange Gas	Design Day	437	229	135	14	0	2	56
8	Damage Claim	Design Day	987	519	306	32	0	4	126
9	Ltd Firm Sales - Rsrvs & \	Design Day	360	189	112	12	0	1	46
10	Distribution Other	Customers	7	6	1	0	0	0	0
11	Miscellaneous Other	1/2 Dsgn Day, 1/2	1,671	732	432	49	71	104	283
12	**Tot Other Oper Rev - Pres**		**4,908**	**3,021**	**1,085**	**108**	**72**	**111**	**511**
13	Incr Late Pay - Proposed	Late Payment Stuc	66	61	4	0	0	0	0
14	Incr Connection Charge R	Customers	691	638	52	0	0	0	0
15	**Tot Other Oper Rev - Prop**		**5,665**	**3,720**	**1,142**	**108**	**73**	**111**	**511**
16a	**Total Oper Rev - Present**		**545,924**	**319,814**	**154,834**	**18,069**	**40,221**	**5,360**	**7,626**
16b	**Total Oper Rev - Proposed**		**581,553**	**347,814**	**160,505**	**18,357**	**40,806**	**6,344**	**7,727**
17	**Operating Rev Increase**		**35,629**	**28,000**	**5,671**	**288**	**584**	**985**	**101**
	Operation & Maintenance (Pg 1 of 2)								
	Purchased Gas Expense	**Allocator**							
18	Commodity	Direct Assign	253,474	133,777	78,680	9,804	31,140	0	73
19	Demand	Direct Assign	66,581	40,418	23,692	2,464	0	0	9
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		320,055	174,195	102,371	12,268	31,140	0	81
	Other Production Expense								
23	Other Purchased Gas	Design Day	439	231	136	14	0	2	56
24	MN Gas MGP Clean Up	Sales, W/o Transp	1,002	524	310	40	127	0	0
25	Misc. LPG Op Exp	Design Day	2,995	1,574	929	96	0	12	384
26	Misc. LNG Op Exp	1/2 Dsgn Day, 1/2	1,223	536	316	36	52	76	207
27	Total Other Production Expense		5,659	2,865	1,691	187	180	90	647
28	Transmission - Average C	Average and Peak	2,419	1,171	691	73	77	114	294
29	Transmission - Other	Other	0	0	0	0	0	0	0
30	**Transmission Expense**		2,419	1,171	691	73	77	114	294
	Distribution Expense								
31	Regulator Stations	Average and Peak	438	212	125	13	14	21	53
32	Mains	Mains, Overall	13,499	10,306	2,050	150	162	232	599
33	Services	Service Study	4,272	3,621	625	7	17	1	0
34	Meters	Meter & Regul Stu	-2,138	-1,708	-387	-13	-27	-3	-1
35	House Regulators	Meter & Regul Stu	1,803	1,439	326	11	22	3	1
36	Rents	Customers	1,466	1,355	110	0	1	0	0
37	Dispatching	1/2 Dsgn Day, 1/2	3,556	1,557	919	105	152	221	601
38	Customer Installations	Customers	1,103	1,019	83	0	1	0	0
39	Other Distribution	Customers	9,266	8,561	696	3	6	1	0
40	Supervision & Engineerin	Dist Exp, w/o Sup	5,840	4,629	798	49	61	84	220
41	Total Distribution Expense		39,105	30,992	5,346	325	410	559	1,473

Class Cost of Service Study ($000); Test Year 2022

INCOME STATEMENT

Operation & Maintenance (Pg 2 of 2)

	Cust Acctg & Inform	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Acct Superv	Customers	1,722	1,591	129	1	1	0	0
2	Acct Meter Read	Customers	4,648	4,294	349	1	3	0	0
3	Acct Recrds & Coll	Record & Coll Stuc	5,439	4,780	355	90	192	17	5
4	Acct Uncollect	Uncollectibles Stuc	2,208	1,849	291	69	0	0	0
5	Acct Misc	Customers	21	19	2	0	0	0	0
6	Asst Expense (w/o CIP)	Cust Inform Study	964	704	215	13	28	2	1
7	Tot Cust Acctg & Inform		15,002	13,237	1,341	174	225	19	5
	Admin & General								
8	Property Insurance	Net Plant	517	378	88	6	6	8	31
9	Pension & Benefit-Direct	Labor	6,730	5,250	981	66	72	83	277
10	Salaries	Labor	5,937	4,632	866	58	63	74	244
11	Office & Supplies	Labor	4,004	3,123	584	39	43	50	165
12	Admin Transfer Credit	Labor	-3,899	-3,042	-569	-38	-42	-48	-160
13	Outside Services	Labor	1,411	1,100	206	14	15	17	58
14	Incentive Compensation	Labor	0	0	0	0	0	0	0
15	Injuries and Claims	1/2 Rt Base, 1/2 Pı	1,323	867	301	30	57	17	52
16	Regulatory Comm Exp	Pres Rev; Mod Pre	548	321	156	18	41	5	7
17	Contributions	Pres Rev; Mod Pre	0	0	0	0	0	0	0
18	General Advertising	1/2 Rt Base, 1/2 Pı	16	11	4	0	1	0	1
19	Misc General Exp	1/2 Rt Base, 1/2 Pı	245	160	56	6	10	3	10
20	Rents	1/2 Rt Base, 1/2 Pı	4,998	3,273	1,137	113	214	66	195
21	Maint of Gen Plt	1/2 Rt Base, 1/2 Pı	40	26	9	1	2	1	2
22	Total A & G Expense		21,869	16,099	3,819	314	481	276	880
	Amortizations								
23	CIP/DSM	Sales, W/o CIP Ex	18,668	9,305	5,496	708	2,251	906	2
24	Amortizations	Labor	167	131	24	2	2	2	7
25	Instructional Advertising	Pres Rev; Mod Pre	241	141	68	8	18	2	3
26	Total Amortizations		19,076	9,577	5,589	718	2,270	911	12
	Sales Expense								
27	Sales, Econ Dvlp & Other	Sales, W/ Transp	34	12	7	1	3	4	7
28	Total Sales Econ Dvlp & Other		34	12	7	1	3	4	7
29	**Total O&M Expense**		**423,219**	**248,147**	**120,854**	**14,058**	**34,786**	**1,973**	**3,400**
	Book Depreciation	**Allocator**							
30	**Production Plant (LPG)**	Design Day	3,085	1,621	957	99	0	13	395
31	**Storage Plant (LNG)**	Design Day	1,529	803	474	49	0	6	196
32	Transmission - Average C	Average and Peak	1,722	833	492	52	55	81	209
33	Transmission - Direct Ass	Direct Assign	308	0	0	0	0	0	308
34	**Transmission Plant**		2,030	833	492	52	55	81	517
	Distribution Plant								
35	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
36	Mains	Mains, Overall	17,643	13,469	2,679	196	212	303	782
37	Services	Service Study	10,906	9,244	1,596	18	45	4	1
38	Meters	Meter & Regul Stu	4,376	3,494	792	27	54	7	2
39	House Regulators	Meter & Regul Stu	1,169	933	212	7	15	2	0
40	Total Distribution Plant		34,094	27,141	5,279	249	326	316	785
41	**General & Common Plar**	Prod-Stor-Tran-Dis	12,392	9,176	2,124	138	130	156	667
42	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
43	**Total Book Deprec**		**53,130**	**39,575**	**9,326**	**586**	**511**	**572**	**2,561**

Class Cost of Service Study ($000); Test Year 2022

INCOME STATEMENT

	Real Estate & Prop Taxes	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	1,122	590	348	36	0	5	144
2	**Storage Plant (LNG)**	Design Day	0.0	0	0	0	0	0	0
3	Transmission - Average C	Average and Peak	1,148	556	328	34	37	54	140
4	Transmission - Direct Ass	Direct Assignment	244	0	0	0	0	0	244
5	**Transmission Plant**		1,392	556	328	34	37	54	384
	Distribution Plant								
6	Regulator Stations	Average and Peak	16,843	8,151	4,811	505	537	793	2,047
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 Stu	0	0	0	0	0	0	0
10	House Regulators	Meter & Regul Stu	0	0	0	0	0	0	0
11	Total Distribution Plant		16,843	8,151	4,811	505	537	793	2,047
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**		**19,358**	**9,297**	**5,487**	**575**	**574**	**851**	**2,574**
15	Payroll Taxes	Labor	2,847	2,221	415	28	30	35	117
16	**Tot Non-Income Taxes**		**22,205**	**11,518**	**5,902**	**603**	**604**	**886**	**2,691**
	Provision-Defer Inc Tax	**Allocator**							
17	**Production Plant (LPG)**	Design Day	570	299	177	18	0	2	73
18	**Storage Plant (LNG)**	Design Day	393	207	122	13	0	2	50
19	Transmission - Average C	Average and Peak	806	390	230	24	26	38	98
20	Transmission - Direct Ass	Direct Assign	87	0	0	0	0	0	87
21	**Transmission Plant**		893	390	230	24	26	38	185
	Distribution Plant								
22	Regulator Stations	Average and Peak	1	1	0	0	0	0	0
23	Mains	Mains, Overall	271	207	41	3	3	5	12
24	Services	Service Study	-555	-471	-81	-1	-2	0	0
25	Meters	Meter & Regul Stu	176	141	32	1	2	0	0
26	House Regulators	Meter & Regul Stu	-86	-69	-16	-1	-1	0	0
27	Total Distribution Plant		-193	-191	-23	3	2	5	12
28	**General and Common Pl**	Prod-Stor-Tran-Dis	804	596	138	9	8	10	43
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	490	383	72	5	5	6	20
32	**Tot Prov Defer Inc Tax**		**2,957**	**1,683**	**715**	**72**	**42**	**63**	**384**
	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	-77	-15	-1	-1	-2	-4
40	Services	Service Study	0	0	0	0	0	0	0
41	Meters	Meter & Regul Stu	0	0	0	0	0	0	0
42	House Regulators	Meter & Regul Stu	0	0	0	0	0	0	0
43	Total Distribution Plant		-101	-77	-15	-1	-1	-2	-4
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**		**-107**	**-80**	**-17**	**-1**	**-1**	**-2**	**-5**
47	**Total Operating Exp**		**501,405**	**300,843**	**136,780**	**15,318**	**35,941**	**3,492**	**9,031**
42a	**Pres Op Inc Before Inc Tax**		**44,519**	**18,971**	**18,054**	**2,752**	**4,280**	**1,867**	**-1,405**
42b	**Prop Op Inc Before Inc Tax**		**80,148**	**46,971**	**23,725**	**3,039**	**4,865**	**2,852**	**-1,304**

Class Cost of Service Study ($000); Test Year 2022

INCOME STATEMENT

	Tax Deprec & Removal	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	5,228	2,747	1,621	168	0	21	670
2	**Storage Plant (LNG)**	Design Day	3,180	1,671	986	102	0	13	407
3	Transmission - Average Capa	Average and Peak	4,705	2,277	1,344	141	150	221	572
4	Transmission - Direct Assign	Direct Assign	662	0	0	0	0	0	662
5	**Transmission Plant**		5,367	2,277	1,344	141	150	221	1,234
	Distribution Plant								
6	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
7	Mains	Mains, Overall	24,021	18,338	3,648	267	289	413	1,065
8	Services	Service Study	8,792	7,452	1,286	14	36	3	1
9	Meters	Meter & Regul Study	4,728	3,775	856	30	59	7	2
10	House Regulators	Meter & Regul Study	419	335	76	3	5	1	0
11	Total Distribution Plant		37,960	29,900	5,866	314	389	424	1,067
12	**General and Common Plan**	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) Ca	Net Plant	18,499	13,520	3,159	219	209	269	1,124
15	**Total Tax Depreciation**		**70,234**	**50,116**	**12,976**	**943**	**748**	**949**	**4,503**
	Present Return								
	Inc Tax Additions	**Allocator**							
16	Total Book Depr Exp		53,130	39,575	9,326	586	511	572	2,561
17	Provision for Deferred		2,957	1,683	715	72	42	63	384
18	Net Inv Tax Credit		-107	-80	-17	-1	-1	-2	-5
19	Avoided Tax Interest	CWIP	704	509	125	10	8	11	41
20	Total Tax Additions		56,684	41,687	10,149	666	559	644	2,981
	Inc Tax Deductions								
21	Tax Depr & Removal Exp		70,234	50,116	12,976	943	748	949	4,503
22	Debt Interest Expense	; Mod Rate Base	18,222	13,196	3,113	222	207	303	1,180
23	Other Timing Differences	Labor	-894	-698	-130	-9	-10	-11	-37
24	Meals	Labor	106	83	15	1	1	1	4
25	Total Tax Deductions		87,667	62,697	15,974	1,158	946	1,242	5,651
26a	**Pres Taxable Net Income**		**13,537**	**-2,039**	**12,229**	**2,260**	**3,893**	**1,269**	**-4,075**
26b	**Prop Taxable Net Income**		**49,165**	**25,961**	**17,899**	**2,547**	**4,478**	**2,254**	**-3,974**
27a	**Pres Inc Tax, @28.74%**		**3,891**	**-586**	**3,515**	**649**	**1,119**	**365**	**-1,171**
27b	**Prop Inc Tax, @28.74%**		**14,131**	**7,462**	**5,145**	**732**	**1,287**	**648**	**-1,142**
28a	**Pres Preliminary Return**		40,629	19,557	14,540	2,102	3,161	1,502	-234
28b	**Prop Preliminary Return**		66,017	39,509	18,581	2,307	3,578	2,204	-162
29	**Total AFUDC**	CWIP	**3,693**	**2,633**	**681**	**56**	**39**	**56**	**228**
30a	**Pres Total Return**	; Mod Rate Base	**44,321**	**22,190**	**15,221**	**2,158**	**3,200**	**1,559**	**-6**
30b	**Prop Total Return**	; Mod Rate Base	**69,710**	**42,142**	**19,262**	**2,363**	**3,616**	**2,261**	**66**
31a	**Pres % Return on Rate Base**		**4.74%**	**3.28%**	**9.53%**	**18.95%**	**30.16%**	**10.03%**	**-0.01%**
31b	**Prop % Return on Rate Base**		**7.46%**	**6.23%**	**12.06%**	**20.75%**	**34.09%**	**14.55%**	**0.11%**
32a	**Pres Common Return**		**26,100**	**8,994**	**12,108**	**1,936**	**2,993**	**1,256**	**(1,186)**
32b	**Prop Common Return**		**51,488**	**28,946**	**16,149**	**2,141**	**3,409**	**1,958**	**(1,115)**
33a	**Pres % Ret on Common Rt Bs**		**5.32%**	**2.53%**	**14.45%**	**32.38%**	**53.74%**	**15.40%**	**-3.73%**
33b	**Prop % Ret on Common Rt Bs**		**10.50%**	**8.15%**	**19.27%**	**35.81%**	**61.22%**	**24.00%**	**-3.51%**
	AFUDC								
34	Production Plant (LPG)	Design Day	292	153	91	9	0	1	37
35	Storage Plant (LNG)	Design Day	312	164	97	10	0	1	40
36	Transmission - Average Capa	Average and Peak	110	53	31	3	4	5	13
37	Transmission - Direct Assign	Direct Assign	0	0	0	0	0	0	0
38	Transmission Plant	Average and Peak	110	53	31	3	4	5	13
	Distribution:								
39	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
40	Mains	Mains Overall	2,452	1,872	372	27	29	42	109
41	Services	Service Study	0	0	0	0	0	0	0
42	Meters	Meter & Regul Study	0	0	0	0	0	0	0
43	House Regulators	Meter & Regul Study	2	1	0	0	0	0	0
44	Total Distribution		2,454	1,874	373	27	30	42	109
45	General Plant	Prod-Stor-Tran-Dis	525	388	90	6	6	7	28
46	Gas Common	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
47	Total AFUDC		3,693	2,633	681	56	39	56	228
	Labor Allocator	**Allocator**							
48	Customer Accounting	Customers	3,190	2,948	239	1	2	0	0
49	Cust Serv & Inform	Customers	644	595	48	0	0	0	0
50	Distribution	Dist Exp, w/o Sup &	23,517	18,638	3,215	195	246	336	886
51	Admin & General	Labor w/o A&G	12,955	10,107	1,889	127	138	161	533
52	Production	Other Production Exp	2,423	1,226	724	80	77	39	277
53	Sales	Sales, W/ Transp	0	0	0	0	0	0	0
54	Transmission	Design Day	701	368	217	23	0	3	90
55	Total		43,429	33,881	6,333	426	464	539	1,786

Class Cost of Service Study ($000); Test Year 2022

	Internal Allocators	**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**43.80%**	**25.86%**	**2.95%**	**4.26%**	**6.23%**	**16.91%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**65.49%**	**22.75%**	**2.27%**	**4.28%**	**1.32%**	**3.90%**
3	Average and Peak (Mains)	310,347	150,192	88,639	9,301	9,897	14,604	37,714
4	Average and Peak	**100.00%**	**48.39%**	**28.56%**	**3.00%**	**3.19%**	**4.71%**	**12.15%**
5	CWIP	**100.00%**	**72.30%**	**17.77%**	**1.40%**	**1.12%**	**1.60%**	**5.80%**
6	Dist Exp, w/o Sup & Eng	33,265	26,363	4,547	276	348	476	1,253
7	Dist Exp, w/o Sup & Eng	**100.00%**	**79.25%**	**13.67%**	**0.83%**	**1.05%**	**1.43%**	**3.77%**
8	Distribution Plant	**100.00%**	**78.93%**	**15.38%**	**0.81%**	**1.00%**	**1.10%**	**2.78%**
9	Gas Plant In Service	**100.00%**	**74.05%**	**17.14%**	**1.11%**	**1.05%**	**1.26%**	**5.39%**
10	Labor	**100.00%**	**78.02%**	**14.58%**	**0.98%**	**1.07%**	**1.24%**	**4.11%**
11	Mains, Overall	**100.00%**	**76.34%**	**15.19%**	**1.11%**	**1.20%**	**1.72%**	**4.43%**
12	Modified O&M Expense	415,808	243,348	119,124	13,882	34,444	1,879	3,132
13	Modified O&M Expense	**100.00%**	**58.52%**	**28.65%**	**3.34%**	**8.28%**	**0.45%**	**0.75%**
14	Net Plant	**100.00%**	**73.08%**	**17.08%**	**1.18%**	**1.13%**	**1.45%**	**6.08%**
15	Other Production Exp	**100.00%**	**50.62%**	**29.88%**	**3.30%**	**3.17%**	**1.59%**	**11.43%**
16	Prod-Stor-Tran-Dis	1,602,732	1,186,799	274,752	17,793	16,859	20,209	86,320
17	Prod-Stor-Tran-Dis	**100.00%**	**74.05%**	**17.14%**	**1.11%**	**1.05%**	**1.26%**	**5.39%**
18	Rate Base	**100.00%**	**72.42%**	**17.09%**	**1.22%**	**1.14%**	**1.66%**	**6.48%**
19	Rt Base, w/o Work Cash	948,195	684,773	163,592	11,846	11,747	15,599	60,639
20	Rt Base, w/o Work Cash	**100.00%**	**72.22%**	**17.25%**	**1.25%**	**1.24%**	**1.65%**	**6.40%**
21	Transmission & Distribution	1,485,874	1,125,386	238,510	14,040	16,859	19,732	71,347
22	Tran & Distrib	**100.00%**	**75.74%**	**16.05%**	**0.94%**	**1.13%**	**1.33%**	**4.80%**
23	Labor w/o A&G	30,474	23,775	4,444	299	326	378	1,253
24	Labor w/o A&G	**100.00%**	**78.02%**	**14.58%**	**0.98%**	**1.07%**	**1.24%**	**4.11%**
	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%**

Class Cost of Service Study ($000); Test Year 2022

External Allocators

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
	Customer-Related							
1	Bills	5,769,904	5,331,144	433,106	1,680	3,578	312	84
2	Modified Bills	5,769,880	5,331,144	433,106	1,680	3,578	312	60
3	Meter & Regul Weightings		1.00					
4	Meter (Wtd Bills)	6,676,602	5,331,144	1,208,206	41,666	83,075	10,106	2,404
5	Service Weightings		1.00					
6	Service (Wtd Bills)	6,289,898	5,331,144	920,303	10,241	25,693	2,123	394
7	Records & Collect Weightings		1.00					
8	Records & Collect (Wtd Bills)	6,066,858	5,331,144	396,474	100,800	214,680	18,720	5,040
9	Cust Information Weightings		1.00					
10	Cust Information (Wtd Bills)	7,295,596	5,331,144	1,628,092	100,800	212,880	17,640	5,040
11	Customers	100.00%	92.40%	7.51%	0.03%	0.06%	0.01%	0.00%
12	Modified Customers	100.00%	92.40%	7.51%	0.03%	0.06%	0.01%	0.00%
13	Meter & Regul Study	100.00%	79.85%	18.10%	0.62%	1.24%	0.15%	0.04%
14	Service Study	100.00%	84.76%	14.63%	0.16%	0.41%	0.03%	0.01%
15	Record & Coll Study	100.00%	87.87%	6.54%	1.66%	3.54%	0.31%	0.08%
16	Cust Inform Study	100.00%	73.07%	22.32%	1.38%	2.92%	0.24%	0.07%
	Energy-Related							
17	Cal Yr Sales Dkt, W/o Trans	74,413,192	38,929,911	23,001,688	2,990,585	9,468,854	0	22,154
18	Transportation Dkt	36,698,763	0	0	0	0	13,381,819	23,316,943
19	Cal Yr Sales Dkt, W/ Trans	111,111,955	38,929,911	23,001,688	2,990,585	9,468,854	13,381,819	23,339,097
20	CIP Exempt Dkt	33,010,988	0	8,817	28,959	53,103	9,590,304	23,329,805
21	Sales Dkt, W/o CIP Exempt	78,100,967	38,929,911	22,992,872	2,961,626	9,415,750	3,791,516	9,292
22	Sales, W/o Transp	100.00%	52.32%	30.91%	4.02%	12.72%	0.00%	0.03%
23	Sales, W/ Transp	100.00%	35.04%	20.70%	2.69%	8.52%	12.04%	21.01%
24	Sales, W/o CIP Exempt	100.00%	49.85%	29.44%	3.79%	12.06%	4.85%	0.01%
25	Modified Sales W/Transport	100.00%	37.95%	22.42%	2.92%	9.23%	13.05%	14.43%
	Demand-Related							
26	Design Day Demand (Retail)	881,141	463,074	273,275	28,294	0	3,598	112,900
27	Avg Daily Firm Dkt, W/ Trans	243,354	106,657	63,018	8,193	0	1,591	63,894
28	Excess Design Day	637,787	356,417	210,257	20,100	0	2,007	49,006
29	Design Day	100.00%	52.55%	31.01%	3.21%	0.00%	0.41%	12.81%
30	Excess Design Day	100.00%	53.91%	31.80%	3.04%	0.00%	0.30%	10.95%
	Miscellaneous (only alloc to class, not component)							
31	Present Retail Revenue	541,016	316,793	153,749	17,962	40,149	5,248	7,115
32	Uncollectibles Study	100.00%	83.72%	13.16%	3.12%	0.00%	0.00%	0.00%
33	Present Retail Revenue	100.00%	58.56%	28.42%	3.32%	7.42%	0.97%	1.32%
34	Late Payment Study	100.00%	93.22%	6.64%	0.08%	0.06%	0.00%	0.00%

Class Cost of Service Study ($000); Test Year 2022

	Capital Structure	**Rate**	**Ratio**	**Wtd Cost**
1	Long Term Debt	4.13%	46.89%	1.94%
2	Short Term Debt	0.94%	0.61%	0.01%
3	Debt Total	4.11%	47.50%	1.95%
4	Preferred Stock	0.00%	0.00%	0.00%
5	Common Equity	10.50%	52.50%	5.51%
6	Required Rate of Return		100.00%	7.46%
7	MN Combined State & Fed Tax Rate	28.74%		
8	1 / (1 - Tax Rate) Factor	140.34%		
9	Tax Rate / (1 - Tax Rate) Factor	40.34%		

OTHER SUPPLEMENTAL INFORMATION
(Part 7825.4400)

The following supplemental information as required by part 7825.3800 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.


ESSENTIAL
2020 ANNUAL REPORT
Xcel Energy®

FOWKE ADVOCATES FOR RACIAL EQUITY AS EEI CHAIR

In June, Xcel Energy Chairman and CEO Ben Fowke was elected Chairman of Edison Electric Institute, our industry trade association, after serving as Vice Chair last year. He originally planned to focus on the clean energy transition and COVID-19 recovery, but two weeks before his one-year term began, Ben and most of the country saw the footage of George Floyd's death while in police custody in south Minneapolis.

Calling the incident that occurred only a few miles from Xcel Energy's corporate headquarters "an awakening," Ben knew that addressing racial equity was too important to not include in his platform. Ben, who was named 2020 Executive of the Year by Utility Dive, quickly rallied the industry and gained commitments from 57 CEOs to address racial equity in their companies and communities, starting with four core principles: 1) Ensuring diversity, equity and inclusion efforts are driven from the top 2) Removing barriers to entry and broadening talent pools 3) Establishing strong community connections, and 4) Developing infrastructure academies and training programs.

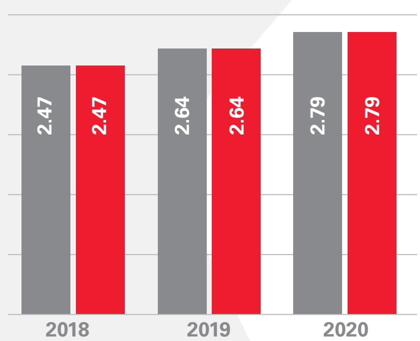
Xcel Energy added a diversity, equity and inclusion corporate scorecard metric for 2021, tying executive and employee compensation to demonstrate our commitment to diversity, equity and inclusion and improved hiring and sponsorship practices. This metric is designed to create accountability in our leadership team and the company as a whole to reduce the barriers to a diverse workforce.

FINANCIAL HIGHLIGHTS

	2019	2020
Total GAAP earnings per share	2.64	2.79
Ongoing earnings per share	2.64	2.79
Dividends annualized	1.62	1.72
Stock price (close)	63.49	66.67
Assets (millions)	50,448	53,957

EARNINGS PER SHARE

Dollars per share (diluted)

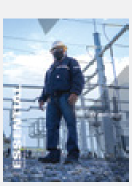


GAAP (generally accepted accounting principles) earnings per share

Ongoing earnings per share

COMPANY DESCRIPTION

Xcel Energy is a major U.S. electric and natural gas company with annual revenues of $11.5 billion. Based in Minneapolis, Minnesota, the company operates in eight states and provides a comprehensive portfolio of energy-related products and services to 3.7 million electricity customers and 2.1 million natural gas customers.



ON THE COVER:
Adolphus Ugeh, a member of our Transmission Field Operations team, is pictured at a new transmission substation near Golden, Colorado. He is one of thousands of Xcel Energy essential workers responsible for providing safe, reliable energy for our customers.

Ben Fowke
Chairman and
Chief Executive Officer

DEAR FELLOW SHAREHOLDERS:

2020 was a year like no other, and I am proud to say the Xcel Energy team rose to the challenge. In the face of a global pandemic, a severe economic downturn and widespread civil unrest, we delivered on our financial and operational objectives while simultaneously mitigating the impacts of COVID-19 and supporting our communities like never before.

We continue to lead the clean energy transition and make excellent progress toward our vision to provide 100% carbon-free electricity for our customers by 2050. At the end of 2020, 47% of the energy we produced came from carbon-free sources. That number will continue to climb as we execute our plans to retire coal plants, build large-scale renewable projects, preserve our high-performing nuclear fleet and maintain natural gas as a bridge and backup fuel. A diversified energy mix is critical during this transition to enhance reliability and keep customer bills low.

We've reduced carbon emissions 51% since 2005 — halfway to our 2050 goal and ahead of schedule — and we are creating concrete pathways to reach our 80% reduction goal by 2030. I'm encouraged by the opportunity to take our increasingly green product and reduce carbon from the transportation sector. Last year, we announced a bold vision to power 1.5 million electric vehicles in our service areas by the end of 2030 (see story on pages 6-8) and launched a comprehensive strategy to lower greenhouse gas emissions from our natural gas business.

For me, 2020 will always be remembered as the year that our employees delivered for our customers and communities in extraordinary times. We never take for granted the trust you place in us to power the homes and businesses of our customers all day, every day. It's a tremendous responsibility that took on additional meaning during this global pandemic.

We chose "Essential" as the theme for this report because of the essential role we play in our communities and in our society. Electricity and natural gas are essential services provided by our essential workers who take great pride in their ability to deliver for their neighbors. We also play a vital role in driving economic development and giving back through the Xcel Energy Foundation. Last year, we earmarked $20 million in short- and long-term corporate giving, including support for COVID-19 recovery and racial justice (see story on pages 16-18).

I take great pride in our team's resiliency, determination and flexibility last year as we learned to work differently, keep each other safe and deliver for our customers, our communities and you, our valued shareholders.

STRONG FINANCIAL PERFORMANCE

For the 16th consecutive year, we met or exceeded our earnings guidance. We delivered 2020 earnings of $2.79 per share, within our original earnings guidance range of $2.73-$2.83 per share, compared to $2.64 per share in 2019. Although electric sales declined approximately 3% due to the economic downturn, we successfully implemented continuous improvement initiatives and other cost control measures that reduced our O&M expenses by nearly 1%.

Xcel Energy also increased your dividend by 6.2%, or 10 cents annually in 2020. We maintained our earnings and dividend growth objectives of 5% to 7% annually, reflecting our confidence in our long-term financial plan. In February 2021, we increased the dividend 6.4%, or 11 cents on an annual basis, extending our streak of dividend growth to 18 consecutive years.

As a result of our continued strong performance, our one-year total shareholder return exceeded 7.8% in 2020, which was the second highest in our peer group. We also compare favorably to our peer group and the S&P 500 for three-, five- and 10-year performance results.

Due to the sound execution of our strategic priorities — leading the clean energy transition, enhancing the customer experience and keeping bills low — we remain well positioned to deliver for our customers and shareholders in 2021 and beyond.

STEEL FOR FUEL EXECUTION

Our Steel for Fuel growth strategy — building wind farms that deliver both economic and environmental benefits for our customers and stakeholders — continues to drive organic growth for the company. Under Steel for Fuel, we add carbon-free renewable energy — the "steel" — allowing our customers to avoid the cost of fuel that would otherwise be used to produce electricity in traditional generating plants. This strategy keeps customer bills low, drives economic development and generates an attractive shareholder return.

In the last year, we added nearly 1,500 megawatts of company-owned wind to our system, including large self-build projects in Colorado, Minnesota and New Mexico. In 2021, we will complete the four remaining projects in our nation-leading multi-state wind expansion that began in 2017. With completion of those remaining projects, the total wind on our system will grow to approximately 11,000 megawatts, including nearly 4,500 megawatts of owned wind capacity (see story on pages 12-13).

Our investments in wind will continue longer term, including wind repowering projects where we replace aging equipment with the latest technology to increase wind farm efficiency and save customers money. We completed two wind repowering projects in 2020 and received approval in December to repower four projects in the Upper Midwest to help stimulate the economy (see story on page 9).

OPERATIONAL EXCELLENCE

Delivering natural gas and electricity took on even greater prominence during the pandemic, and our workforce delivered while adjusting to enhanced safety precautions (see story on pages 14-15). We met or exceeded goals on all 2020 corporate scorecard metrics, including customer satisfaction, wind deployment, employee safety, public safety and electric system reliability.

Operational highlights include our J.D. Power customer satisfaction score improving by 40 points to our highest rating ever. The Institute of Nuclear Power Operations rated our nuclear fleet as the best in the nation — we achieved a

96% capacity factor and successfully executed a refueling at Prairie Island during the pandemic. And we began the pivotal evolution of our safety approach that focuses on eliminating serious injuries and fatalities. Under this "Safety Always" approach, we are developing a culture of enhanced trust and transparency with our employees, giving them the opportunity to learn from their experiences and continuously improve the safety of their work environment.

REGULATORY PROGRESS

We achieved constructive outcomes in numerous regulatory proceedings in 2020, including rate case settlements in New Mexico, Texas and Colorado and approval of our proposal to avoid moving forward with a rate case in Minnesota when many customers are struggling financially. The Minnesota Public Utilities Commission continues to review our resource plan that will determine the future energy mix in the Upper Midwest, and we expect a decision in 2021.

We recently filed a Colorado Clean Energy Plan that includes adding 5,500 MW of wind, solar and energy storage. It also proposes the early retirement or conversion to natural gas of our remaining coal plants in Colorado. If approved along with a supplemental filing to expand the transmission network in the state, we expect to generate approximately 80% of our energy from renewable sources in Colorado by 2030, reducing our carbon emissions by approximately 85% from 2005 levels while maintaining system reliability and customer affordability. We also came to a resolution with the City of Boulder for a new 20-year franchise agreement.

To support our vision of powering 1.5 million electric vehicles in our service areas by 2030, we filed transportation electrification plans in Colorado, Minnesota, New Mexico and Wisconsin and gained approval for new home charging programs in Minnesota and Wisconsin.

As we look to achieve our vision of producing 100% carbon-free electricity for our customers by 2050, we initiated the Carbon-free Technology Initiative. This working group stretches across all aspects of Xcel Energy, along with strategic partners such as Edison Electric Institute, other utilities, leading venture capital investors and environmental groups. The goal is to support the advancement, funding and policies supportive of technologies critical to achieving our carbon-free goals. As an example, in 2020 we entered into partnership with the Department of Energy to test the viability of producing carbon-free hydrogen at one of our nuclear plants.

BEST IN THE BUSINESS

Resiliency and flexibility are characteristics that we seek in our generation assets, but this year those terms accurately describe our employees that I believe are the best in the business. It's an honor and a privilege to lead this team that is so committed to serving our customers and living our values: Committed, Connected, Safe and Trustworthy.

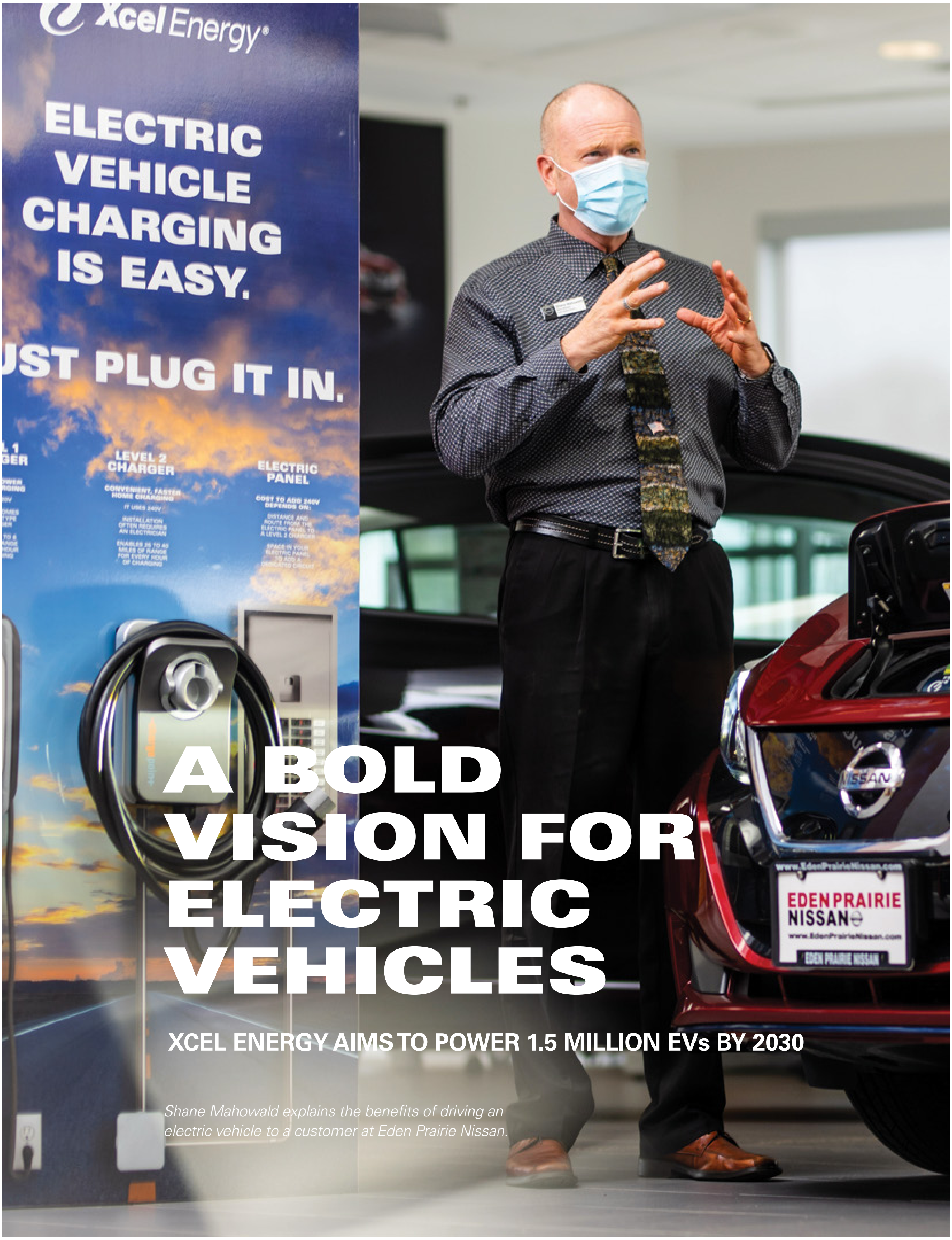
It shouldn't come as a surprise that our employees continue to receive recognition for their efforts and our workplace culture. For the eighth consecutive year, we were selected for Fortune Magazine's "World's Most Admired" companies list. Ethisphere named us among the "2021 World's Most Ethical Companies" — it's the second consecutive year we received that honor. Our field crews received two EEI Emergency Recovery Awards for their efforts to restore service following Winter Storm Billy, an October ice storm that caused significant damage to the grid in Texas, and for restoring power to 135,000 Minnesota residents following a summer storm that rolled through the Twin Cities.

As we look at 2021, we know that there are challenges ahead. We've already seen the impact of a historic cold snap, and although the rollout of vaccines provides renewed optimism that we can put COVID-19 in the rearview mirror, the pandemic is not over.

But our performance in 2020 is a reason for optimism. Regardless of whatever new challenges arise, you can count on the Xcel Energy team to deliver for you.

Sincerely,

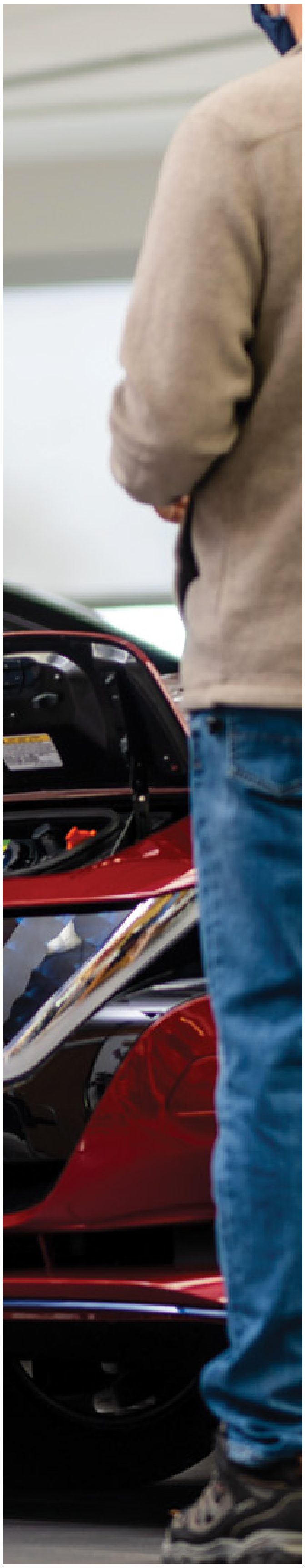
Ben Fowke
Chairman and Chief Executive Officer



A BOLD VISION FOR ELECTRIC VEHICLES

XCEL ENERGY AIMS TO POWER 1.5 MILLION EVs BY 2030

Shane Mahowald explains the benefits of driving an electric vehicle to a customer at Eden Prairie Nissan.



AS ELECTRIC VEHICLES (EVs) HAVE EVOLVED AND GAINED PROMINENCE DURING THE PAST DECADE, SHANE MAHOWALD HAS WITNESSED A NOTICEABLE UPTICK IN THE NUMBER OF CUSTOMERS INQUIRING ABOUT THE BENEFITS AND SUBSEQUENTLY PURCHASING THEIR FIRST EV.

"The excitement level for EVs has risen dramatically, especially in the last year," said Mahowald, the General Sales Manager at Eden Prairie Nissan in Minnesota. "A growing percentage of customers want their next car purchase to be an EV. That just wasn't the case a few years back. They see the trend and want to take advantage of the economic and environmental benefits."

Those benefits include: no oil changes or engine maintenance; low-cost overnight charging instead of filling up at the gas pump; reduced emissions; generous rebates and tax credits; and improved battery technology compared to earlier models.

General Motors recently announced its plans to phase out the production of gas and diesel-powered vehicles by 2035, and other automakers are expected to announce similar goals.

"Electric vehicle adoption will grow substantially in the coming years, and we want to be at the leading edge of that wave — powering the cars with our clean, affordable energy, while also providing our customers with the programs they want — from innovative community electric rideshare partnerships to installing at-home chargers with an easy process," said Brett Carter, Chief Customer and Innovation Officer at Xcel Energy. "That's why in August of 2020 we announced a bold vision to power 1.5 million electric vehicles in our service areas by the end of the decade."

That means about 20% of all cars on the road in our service territory would be electric, saving customers an estimated $1 billion in annual fuel costs by 2030 and removing approximately 5 million tons of carbon annually by the same year.

Regulators in Colorado, Minnesota and Wisconsin have approved various programs to support EV adoption for business and residential customers, with more states expected to follow in 2021 and beyond.

"One of our key objectives is making the EV purchasing experience and set-up of home charging equipment as easy as possible for our customers," said Nadia El Mallakh, Area Vice President of Strategic Partnerships.

An example of how we are reaching potential buyers is placing Xcel Energy

EV educational pillars at car dealerships like Eden Prairie Nissan, just outside the Twin Cities. The kiosks offer digital tools, a hands-on experience with charging equipment and the ability for our customers to sign up for a home charging program.

Consumers in Minnesota and Wisconsin can work with Xcel Energy to have a Level 2 fast charger installed at their homes. Our customers can charge their EVs overnight at off-peak rates for the equivalent of less than $1 per gallon of gas. Over the course of a year, those fuel savings can add up to an average of $700.

EV adoption is tailor-made for Xcel Energy's three strategic priorities: leading the clean energy transition, enhancing the customer experience and keeping bills low for customers. Charged on the increasingly clean Xcel Energy system, electric vehicles will have about 80% lower carbon emissions than gas-powered cars by 2030, amounting to about three tons of annual carbon reduction per vehicle.

In addition to residential customers, Xcel Energy is working with companies and municipalities to help convert their fleets to electric vehicles. We have also invested $25 million in public charging mobility hubs in the Twin Cities and are supporting HOURCAR, a St. Paul-based nonprofit ridesharing program to make EVs accessible to lower-income residents.

Colorado regulators recently approved our $110 million Transportation Electrification Plan that will deploy approximately 20,000 EV charging ports at residential, business and public sites across Colorado.

In New Mexico, our proposed Transportation Electrification Plan is specifically geared to support the state's developing marketplace, offering education, incentives and infrastructure needed to expand EV home charging, public charging and fleet operations.

A customer gathers information about the benefits of EVs at an Xcel Energy educational pillar.

PROJECTS DRIVE RECOVERY

EVERY YEAR, XCEL ENERGY DRIVES SIGNIFICANT ECONOMIC DEVELOPMENT ACROSS OUR EIGHT-STATE FOOTPRINT THROUGH CAPITAL INVESTMENT PROJECTS, WAGES AND TAX BASE.

In 2020, the company spent $4.9 billion through our supply chain vendors, with 71% of those dollars supporting local companies in our service territory.

So, it should come as no surprise that the Minnesota Public Utilities Commission and the Minnesota Department of Commerce asked us and other industry peers for proposals to help jumpstart the economy following the COVID-19 economic slowdown.

Our Minnesota Relief and Recovery Act proposal included $3 billion of incremental and accelerated investments to help the region's economic recovery from the impact of COVID-19 and accelerate the clean energy transition. The proposal includes building a 460-megawatt large-scale solar farm next to our Sherco Generating Station, upgrading four company-owned wind farms with the next generation of technology and expanding conservation and energy efficiency programs.

Upgrading the wind farms — which received commission approval in December — will save customers approximately $160 million in energy costs over the next 25 years and create up to 700 local, union construction jobs, in addition to the indirect jobs provided by suppliers. Following construction, the wind farms will increase their annual carbon-free energy output by approximately 20%, on average, compared to today.

Four of our owned wind farms — three in southern Minnesota and one in eastern North Dakota — will be repowered. The wind towers will be rebuilt on the same foundation locations with much larger blades and more efficient turbines. Construction using union labor is expected to begin in 2021.

Nobles Wind Farm in southern Minnesota is one of four wind farms that will be repowered with new technology to help jumpstart the economy.

BISTRO VENDOME, A FRENCH RESTAURANT LOCATED IN LARIMER SQUARE IN DOWNTOWN DENVER, TRANSPORTS PATRONS FROM THE SHADOWS OF THE ROCKIES TO THE HEART OF PARIS.

From weekend brunches and business lunches to romantic dates and family gatherings, the eatery is normally bustling with diners. However, the COVID-19 pandemic and subsequent shutdowns of indoor dining have devastated restaurants like Bistro Vendome. To keep their doors open many Colorado eateries have expanded or renovated their outdoor spaces to provide patrons with a safe, warm dining experience.

Bistro Vendome is one of nearly 400 restaurants in more than 30 Colorado counties to receive a grant from the Winter Outdoor Dining Fund, which the Xcel Energy Foundation kickstarted with a pledge of $750,000 and an initial gift of $500,000. Launched in November 2020 in partnership with the State of Colorado and the Colorado Restaurant Association, the program awards restaurants with grants of up to $10,000 to winterize their outdoor spaces with igloos, heaters, tents and more.

With the grant funds, Bistro Vendome converted its cozy European courtyard hidden by brick walls and shady trees into a large, yet intimate insulated tent flecked with string lights.

"We are grateful to Xcel Energy and other partners for their efforts to help Colorado restaurants survive this winter," said Beth Gruitch, co-partner of Crafted Concepts, which owns Bistro Vendome. "With COVID-19 restrictions, it would have been difficult to stay open without the revenue from our winterized outdoor dining area."

"Powering the homes and businesses of our communities and keeping our customers warm this winter is not enough," said Hollie Velasquez Horvath, Senior Director, State Affairs and Community Relations in Colorado. "We hope this contribution will help Colorado restaurants thrive, while also providing customers a safe and fun dining experience this winter and beyond."

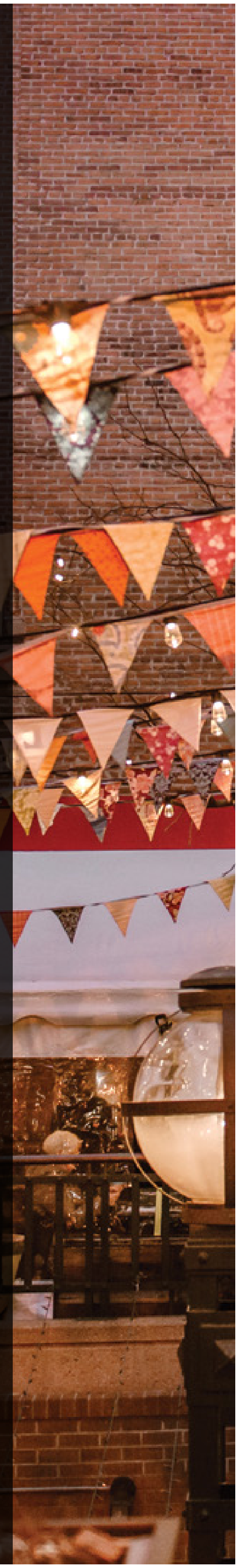
The economic shutdown caused by the global pandemic has hurt many businesses, especially in the hospitality industry. As a company literally embedded in the communities we are privileged to serve, Xcel Energy created a strategy in 2020 to help our customers weather the challenges as best as possible.

We were among the first companies in the industry to suspend disconnections of residential customers behind on their bills and are partnering with customers to set up repayment plans that work for them. We also worked closely with business customers to inform them about federal government loan programs. In Minnesota, the Public Utilities Commission agreed with our recommendation to provide a temporary electric rate discount for business customers affected by the shutdowns.

Account Manager Sara Terrell received a thank-you note from a large hotel in downtown Minneapolis that said in part: "Our business has suffered a $7 million loss this year, and our staffing levels have been reduced to the bare bones. So, when I say we are grateful, I can't find a way to fully express that in words. But the savings provided with this discounted electric rate are helping to keep good people employed."

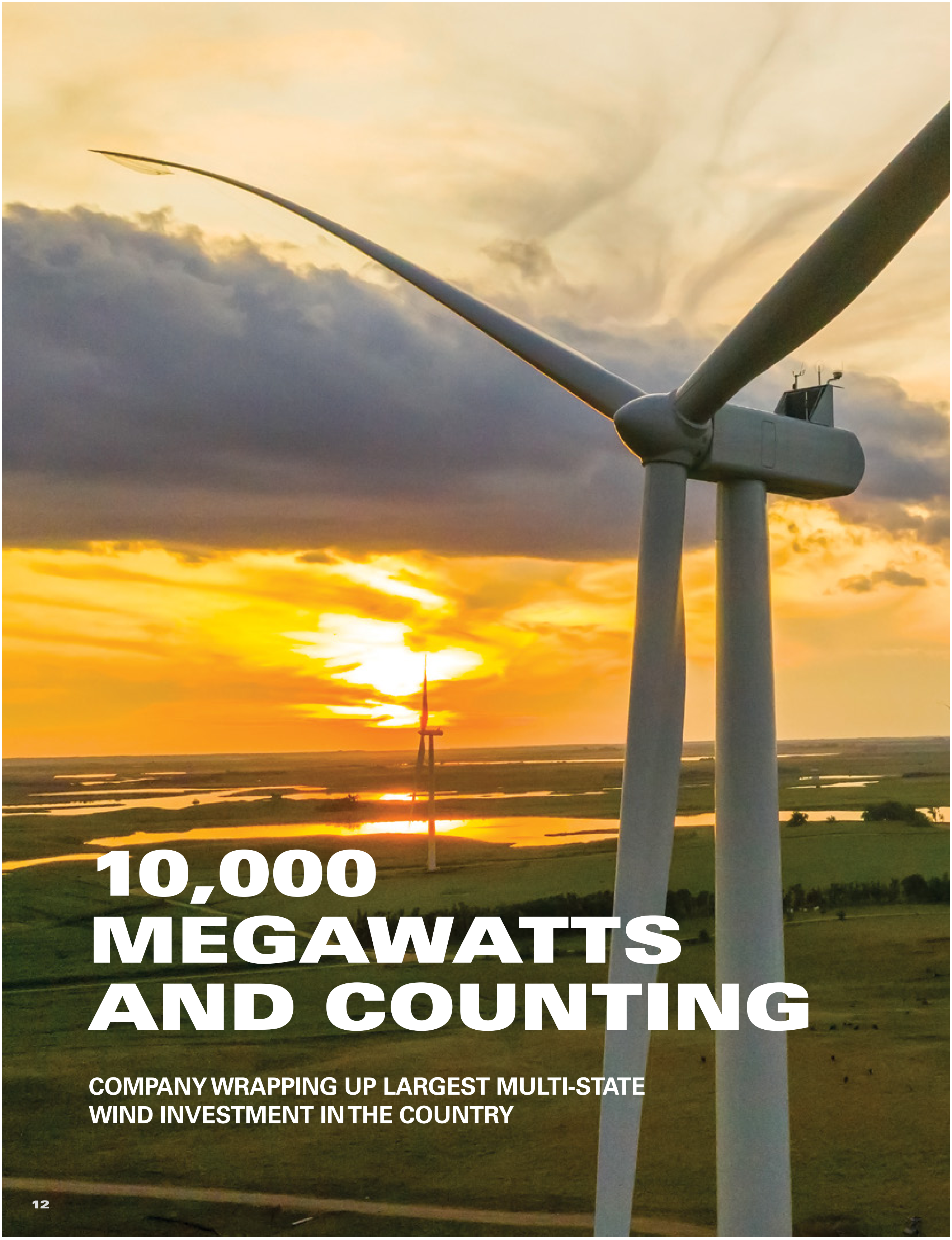
Xcel Energy account managers were in constant contact with their business customers to offer our help.

"Our customers just wanted someone in their corner to listen to their struggles and lend a hand if possible," said Chris Conrad, Director of Account Management in Minnesota. "Helping customers in big and small ways is always important, and this past year demonstrated that more than ever."



HELPING CUSTOMERS WEATHER A PANDEMIC

THE HOSPITALITY INDUSTRY WAS ESPECIALLY HIT HARD BY COVID-19



10,000 MEGAWATTS AND COUNTING

COMPANY WRAPPING UP LARGEST MULTI-STATE WIND INVESTMENT IN THE COUNTRY

DESPITE A GLOBAL PANDEMIC, XCEL ENERGY CONTINUED TO MAKE EXCELLENT PROGRESS IN 2020 ON OUR NATION-LEADING MULTI-STATE WIND EXPANSION THAT IS SCHEDULED TO WRAP UP IN 2021.

The company added nearly 1,500 megawatts of owned wind capacity on the system last year, including the Sagamore Wind Farm in New Mexico and Cheyenne Ridge Wind Farm in Colorado. At approximately 500 megawatts each, these company-owned and operated projects are two of the largest on our system.

Our Steel for Fuel strategy delivers significant environmental benefits, saves customers hundreds of millions of dollars in fuel costs over the life of the projects and provides shareholder value. Our wind ownership portfolio — where we earn an investment return — has grown five-fold in recent years.

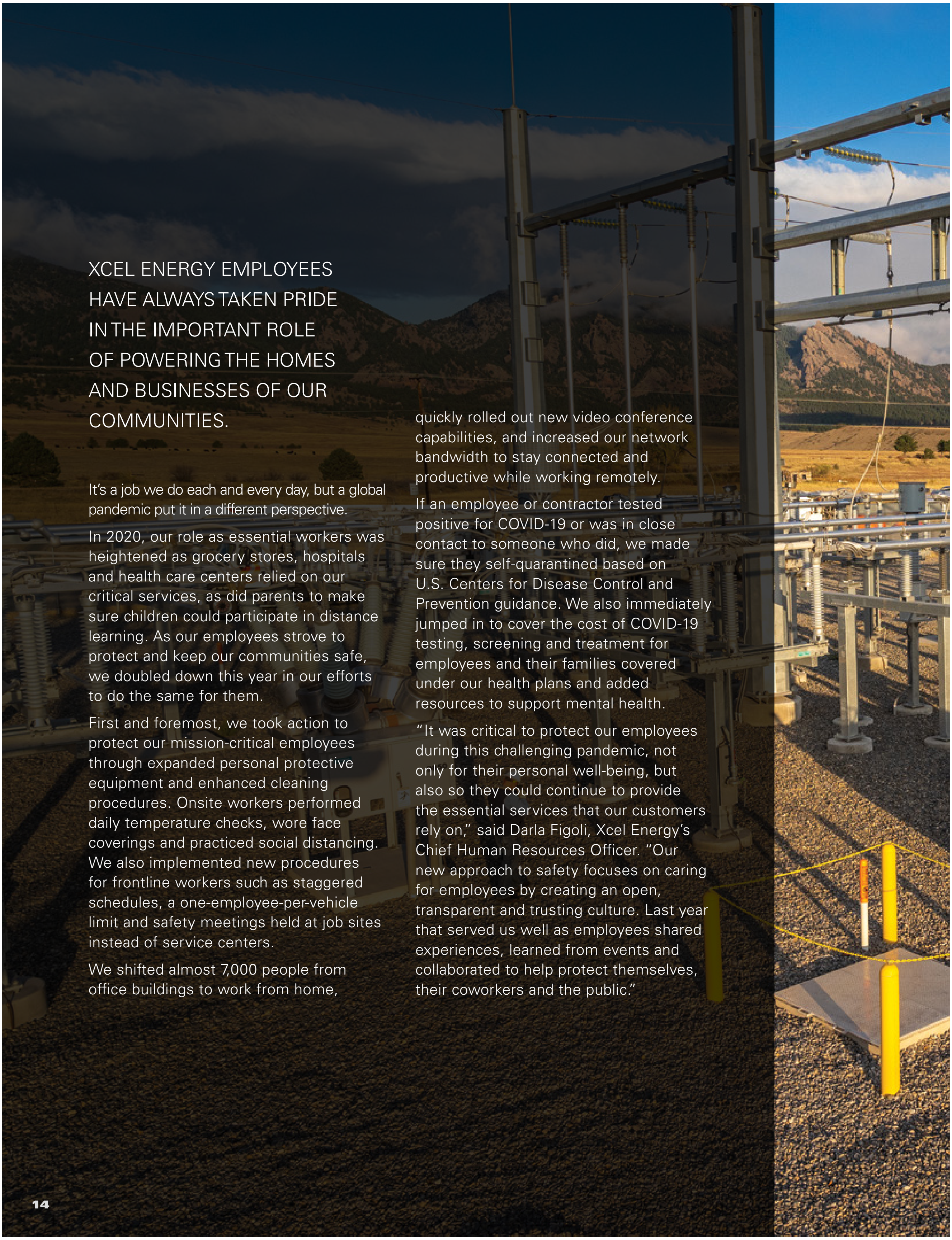
"I'm really proud of the progress we made in 2020. There was a lot of concern the pandemic would slow down the clean energy transition, but it actually strengthened our resolve," said Kim Randolph, Xcel Energy's Vice President of Energy Supply Projects. "We never lost sight of the importance of employee safety and worked with our construction partners to put these huge wind farms into service."

When all the 2020 wind projects were tallied, Xcel Energy became one of the first companies in the country to reach 10,000 megawatts of wind capacity on our system, and we have more on the way. Four additional wind farms will be completed in 2021, adding 800 megawatts to our system, and we also have another 650 megawatts of approved wind repowering projects in the pipeline. Xcel Energy is currently the second-largest utility wind energy provider in the country.

Because of challenges due to COVID-19, the U.S. Congress extended the full production tax credit for an additional year, meaning that wind projects completed in 2021 will cost millions of dollars less, which helps keep bills low for customers.

Xcel Energy has several expiring wind power purchase agreements over the next decade, which are a significant opportunity to buy and repower older wind farms using the latest technology that is more efficient and will save customers money even after those wind farms are retrofitted.

Xcel Energy became the first power company in the country to announce a vision to provide 100% carbon-free electricity for customers by 2050, and an aggressive interim goal of reducing carbon emissions 80% by the end of the decade. By adding a significant amount of large-scale renewable energy, retiring coal units or operating them differently and enhancing energy efficiency programs, the company has reduced carbon emissions 51% at the end of 2020 compared to 2005 levels.



XCEL ENERGY EMPLOYEES HAVE ALWAYS TAKEN PRIDE IN THE IMPORTANT ROLE OF POWERING THE HOMES AND BUSINESSES OF OUR COMMUNITIES.

It's a job we do each and every day, but a global pandemic put it in a different perspective.

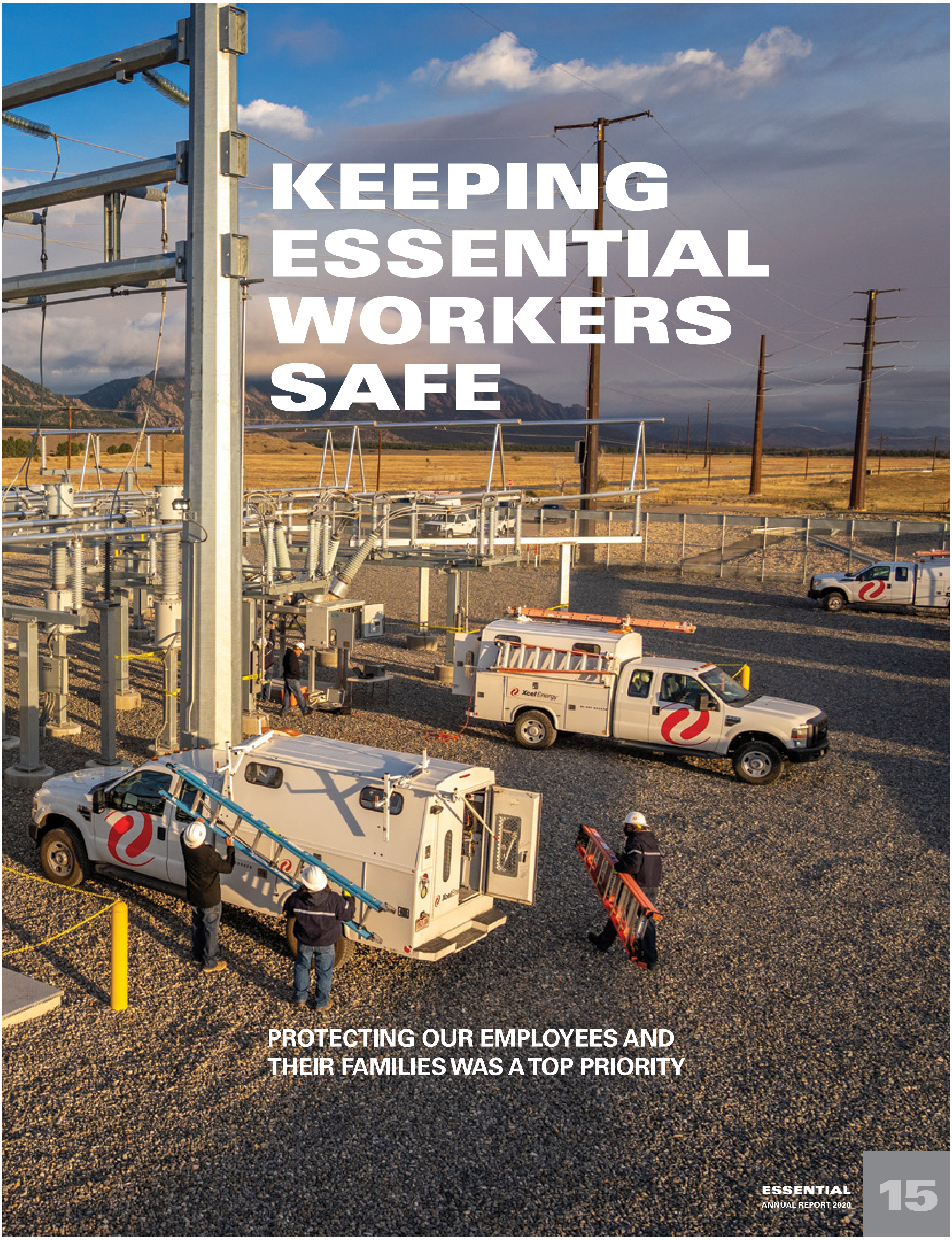
In 2020, our role as essential workers was heightened as grocery stores, hospitals and health care centers relied on our critical services, as did parents to make sure children could participate in distance learning. As our employees strove to protect and keep our communities safe, we doubled down this year in our efforts to do the same for them.

First and foremost, we took action to protect our mission-critical employees through expanded personal protective equipment and enhanced cleaning procedures. Onsite workers performed daily temperature checks, wore face coverings and practiced social distancing. We also implemented new procedures for frontline workers such as staggered schedules, a one-employee-per-vehicle limit and safety meetings held at job sites instead of service centers.

We shifted almost 7,000 people from office buildings to work from home, quickly rolled out new video conference capabilities, and increased our network bandwidth to stay connected and productive while working remotely.

If an employee or contractor tested positive for COVID-19 or was in close contact to someone who did, we made sure they self-quarantined based on U.S. Centers for Disease Control and Prevention guidance. We also immediately jumped in to cover the cost of COVID-19 testing, screening and treatment for employees and their families covered under our health plans and added resources to support mental health.

"It was critical to protect our employees during this challenging pandemic, not only for their personal well-being, but also so they could continue to provide the essential services that our customers rely on," said Darla Figoli, Xcel Energy's Chief Human Resources Officer. "Our new approach to safety focuses on caring for employees by creating an open, transparent and trusting culture. Last year that served us well as employees shared experiences, learned from events and collaborated to help protect themselves, their coworkers and the public."



KEEPING ESSENTIAL WORKERS SAFE

PROTECTING OUR EMPLOYEES AND THEIR FAMILIES WAS A TOP PRIORITY

SUPPORTING OUR COMMUNITIES HAS BEEN A STAPLE AT XCEL ENERGY FOR DECADES, BUT IT TOOK ON UNPRECEDENTED IMPORTANCE IN 2020 WITH THE COMBINATION OF A GLOBAL PANDEMIC, THE SUBSEQUENT ECONOMIC DOWNTURN AND CIVIL UNREST IN MANY OF OUR COMMUNITIES.

Leadership can take several forms, and Xcel Energy has demonstrated community and industry leadership through our quick actions and targeted contributions of hours and dollars.

RACIAL EQUITY

The nation saw searing images of civil unrest in communities across the country in 2020, but among the most notable were in the Twin Cities, only a few miles from Xcel Energy's headquarters, following the death of George Floyd in police custody. The company has committed to help local businesses rebuild with free energy design assistance and double rebates on qualifying energy efficient purchases such as HVAC and lighting systems.

In early 2021, the Xcel Energy Foundation announced $350,000 in grants to 14 nonprofit organizations to fund racial equity programs and rebuild communities in Minneapolis and St. Paul. That comes on the heels of a $300,000 donation to help fund North Star Learning Pods, an innovative program to help reduce the achievement gap for black and minority students. Located at local churches and community centers, learning pods feature tutoring, enrichment experiences and reliable internet connections for hundreds of students to make distance learning more effective in a school year disrupted by the COVID-19 pandemic. We also supported six nonprofits striving for racial equity in Colorado in addition to efforts in our other states.

As a company, we aim to create an inclusive work culture where employees are treated equitably, and diversity is not only accepted but celebrated. Our CEO and senior executives lead by example, fostering an open and accepting work environment through their communications and interactions, which include holding crucial conversations on race relations. We provide enterprise-wide learnings such as unconscious bias and microinequities training, and we sponsor 10 business resource groups to support employee interests and assist the organization in solving challenges and achieving goals. However, our commitment goes beyond programs, policies and practices — we strive for diversity, equity and inclusion ("DEI") to be an integral part of who we are, how we operate and how we see our future. We are committed to progress and will measure our progress through corporate scorecard metrics that include, among other things, employee feedback on our engagement survey inclusion index, the use of diverse hiring interview panels and an executive sponsorship program.

COVID-19 RELIEF

To provide financial relief for communities hard-hit by COVID-19, the company donated $100,000 to six regional and community foundations and three tribal nations in Wisconsin, the first of several contributions across our service territory. In addition to our foundation monetary

DELIVERING FOR OUR COMMUNITIES

FOUNDATION DOLLARS SUPPORT COVID-19 RELIEF, RACIAL EQUITY EFFORTS

contribution, many employees donated their time and used their ingenuity to help make a difference.

Employees across the company sewed and donated masks for family members, friends, neighbors and health care workers in their community. In addition, three employees developed a solution for the ear discomfort many people were experiencing when wearing masks all day. Using a 3-D printer, they created a simple plastic extender that connects to a mask's elastic bands, eliminating the discomfort. The trio initially made 1,900 for Xcel Energy employees, but after hearing that the pieces are expensive for the health care community, they produced thousands of ear protectors a week to donate to frontline health care providers in the Upper Midwest.

THANKING HEALTH CARE WORKERS

One morning in the spring of 2020, hospital workers at two St. Paul hospitals — Regions and Bethesda — received a unique thank you gesture from 60 Xcel Energy employees.

With dozens of bucket trucks and other vehicles, our employees arrived for the morning shift change to thank the health care workers and first responders. Banners with messages of support hung from hoisted buckets, and company employees lined the sidewalks to applaud the medical workers who were either arriving to start their day or just finishing their shift.

"It was the most rewarding day of my career. The raw emotion that we saw and felt that day was awesome. I don't think I'll see anything like that again," said Mitch Quinnell, an Operations Manager based in St. Paul.

Megan Remark, President and CEO of Regions Hospital, agreed. "I want you to know that everywhere I walked at Regions Hospital the following morning, I heard our teams talking about what an amazing morale boost your Xcel Energy team gave all of our caregivers," she wrote in an email. "As you know, essential workers like your team and our team are ready 24/7 to solve any problem and are ready to be there for everyone who needs us. Your grand gesture will live in the minds of our caregivers forever."

GIVING BACK

Our employees have always stepped up to play a significant role in supporting our communities, and that was especially true during the pandemic. The Xcel Energy Foundation encouraged employee giving to their favorite nonprofits with a special 2-for-1 match, resulting in $450,000 of contributions to organizations that needed support more than ever. In total, our employees and the Foundation invested nearly $13 million in our communities in 2020. That includes another successful United Way campaign in which employees raised $2.5 million, exceeding the goal despite having to pivot to virtual activities.

Employees also volunteered approximately 50,000 volunteer hours last year at events like the 10th annual Xcel Energy Day of Service (virtual and modified in-person opportunities) and served on more than 500 nonprofit boards in our communities.

John Marshall, Director of Community Relations & Foundation, delivers special mask extenders to M Fairview Hospital. A trio of Xcel Energy employees produced them using a 3-D printer. Overall, the company donated more than 300,000 masks to hospitals, health care centers and tribal communities.

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, 2020 or

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

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	Name of each exchange on which registered
Common Stock, $2.50 par value	XEL	Nasdaq Stock Market LLC

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

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

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

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

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

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

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

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

As of June 30, 2020, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $32,825,311,125.

As of Feb. 11, 2021, there were 537,648,833 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement for its 2021 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K.

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PART I

ITEM 1 — BUSINESS

Definitions of Abbreviations

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

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

Federal and State Regulatory Agencies

CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
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
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
IRS	Internal Revenue Service
Minnesota District Court	U.S. District Court for the District of Minnesota
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment Clauses

CEPA	Colorado Energy Plan Adjustment
CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	DSM cost adjustment
ECA	Retail electric commodity adjustment
EECRF	Energy efficiency cost recovery factor
EIR	Environmental improvement rider
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
RESA	RES adjustment
SCA	Steam cost adjustment
SEP	State energy policy rider
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor
WCA	Wind cost adjustment

Other

ADIT	Accumulated deferred income taxes
AFUDC	Allowance for funds used during construction
ALLETE	ALLETE, Inc.
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
Boulder	City of Boulder, CO
C&I	Commercial and Industrial
CAGR	Compound annual growth rate
CACJA	Clean Air Clean Jobs Act
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
COVID-19	Novel coronavirus
CWA	Clean Water Act
CWIP	Construction work in progress
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
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
HDD	Heating degree-days
IM	Integrated market
INPO	Institute of Nuclear Power Operations

IPP	Independent power producing entity
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
JOA	Joint operating agreement
LSP Transmission	LSP Transmission Holdings, LLC
MDL	Multi-district litigation
MEC	Mankato Energy Center
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
NAAQS	National Ambient Air Quality Standard
Native load	Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
PI	Prairie Island nuclear generating plant
Post-65	Post-Medicare
PPA	Purchased power agreement
Pre-65	Pre-Medicare
PTC	Production tax credit
REC	Renewable energy credit
ROE	Return on equity
ROFR	Right-of-first-refusal
ROU	Right-of-use
RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCEH	Texas Competitive Energy Holdings
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
TOs	Transmission owners
TSR	Total shareholder return
VaR	Value at Risk
VIE	Variable interest entity
WOTUS	Waters of the U.S.

Measurements

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

Where to Find More Information

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

The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov. The information on Xcel Energy's website is not a part of, or incorporated by reference in, this annual report on Form 10-K.

Xcel Energy intends to make future announcements regarding Company developments and financial performance through its website, www.xcelenergy.com, as well as through press releases, filings with the SEC, conference calls and webcasts.

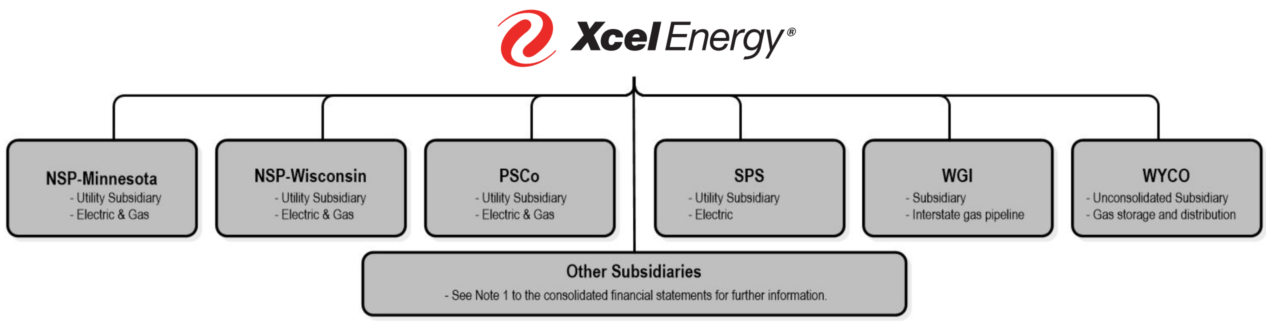
Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2021 EPS guidance, long-term EPS and dividend growth rate objectives, future sales, future bad debt expense, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, and expectations regarding regulatory proceedings, 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, 2020 (including risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs; changes in regulation and subsidiaries' ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

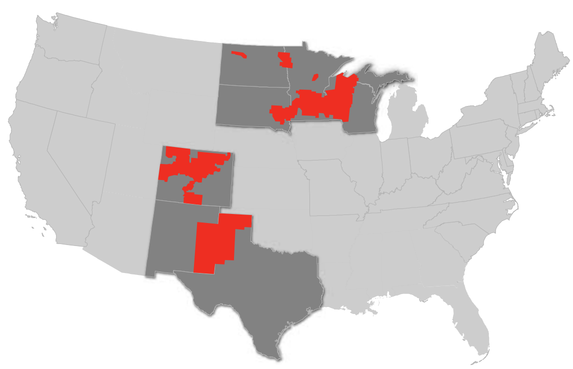
Overview

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



Utility Subsidiaries' Service Territory

Electric customers	3.7 million
Natural gas customers	2.1 million
Total assets	$54 billion
Electric generating capacity	20,140 MW
Natural gas storage capacity	53.4 Bcf
Electric transmission lines (conductor miles)	110,353 miles
Electric distribution lines (conductor miles)	208,586 miles
Natural gas transmission lines	2,172 miles
Natural gas distribution lines	35,936 miles



Vision, Mission and Values

Strategy

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

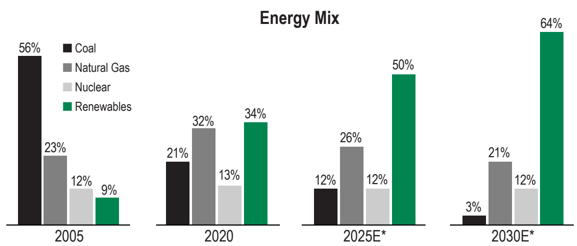
Lead the Clean Energy Transition
Reducing carbon emissions 80% by 2030; 100% carbon-free electricity by 2050

Enhance the Customer Experience
Conservation, renewable and electric vehicle offerings

Keep Bills Low
Average bill increases ≤ rate of inflation

Lead the Clean Energy Transition

For more than a decade, Xcel Energy has proactively managed the risk of climate change and responded to increasing customer demand for renewable energy. We reduced carbon emissions from generation serving customers by 51% from 2005 to 2020 and are on track to reach 60% renewable generation by 2030.



* Potential scenarios that achieve carbon reduction goal

Our recently announced generation transition plans include:

- Adding economic wind and solar resources.
- Limiting coal generation through seasonal dispatch of coal facilities where possible and early retirement of coal plants (e.g., Hayden and Craig), including fully exiting coal in the upper Midwest by 2030 (e.g., Sherco).
- Using natural gas as a means to ensure system reliability.
- Extending the life of our Monticello nuclear plant.
- Converting Harrington, our coal plant in Texas, to natural gas.
- A proposal to close the Hayden coal plant, retiring Unit 2 by the end of 2027 and Unit 1 in 2028.
- Retiring Craig coal plant with Unit 1 closing in 2025 and Unit 2 closing in 2028.

Our March 2021 Colorado resource plan filing will outline a range of options for us to achieve 80% carbon reduction by 2030 in the state, including:

- Proposed plans for our remaining coal units (approximately 1,200 MW), such as early retirements and natural gas conversions.
- Additional renewables and storage.
- Transmission expansion.

We are confident we can achieve our 80% interim carbon reduction goal with today's technology. New carbon-free dispatchable technologies will be required in order to achieve the remaining 20% carbon reduction. Reliability, customer affordability and innovation remain paramount to a successful transition.

Xcel Energy's clean energy leadership extends to our natural gas distribution system as we work to keep our methane emissions rate below 0.2%. Our plans include the following:

- Working with upstream suppliers on reducing emissions on their system.
- Reducing methane emissions from our own operations.
- Designing programs that encourage customer conservation and electrification where beneficial.

Enhance the Customer Experience

Xcel Energy is committed to providing programs that customers want and value. We continue to expand renewable offerings and promote cost savings and conservation programs, in which we have invested over $2 billion in the past decade.

Xcel Energy is transforming our electric grid to accommodate increased levels of renewables and distributed energy resources and continues to offer customers directly sourced renewable energy solutions. We are also working to develop new programs for C&I customers who desire higher than standard service reliability, with the goal being to make it both easy and affordable for business customers to meet their resiliency needs.

Additionally, we have partnered with policymakers, state agencies and innovative partners to develop nation-leading electric vehicle solutions for our customers. Our electric vehicle plans include residential, fleet and public charging offerings. In 2020, our residential, flat-fee subscription service pilot won Public Utility Fortnightly's Smartest Transportation Electrification Project award. Xcel Energy has full or pilot electric vehicle programs underway in Minnesota, Colorado and Wisconsin, including our $110 million, three-year Colorado plan which was approved in December 2020.

In 2020, we set an ambitious goal to power 1.5 million electric vehicles across our service territory by 2030, which is estimated to save customers $1 billion in fueling costs and cut carbon emissions by nearly 5 million tons annually by 2030.

Keep Bills Low

Affordability is foundational to our strategy. Our goal is to keep bill increases at or below the rate of inflation. Xcel Energy has kept residential bills relatively flat since 2013.

Our states benefit from strong wind and solar capacity factors. This geographic advantage, coupled with renewable tax credits and avoided fuel costs, enables Xcel Energy to increase its investment in renewables while saving customers money. We call this our "Steel for Fuel" strategy. From 2017 to 2020, we added nearly 3,000 MW of wind to our system while delivering approximately $430 million in fuel savings to our customers.

Xcel Energy continues to control O&M expense without compromising reliability or safety. Since 2014, total O&M has remained flat and we expect annual growth to remain below 1% through 2025 as declines in base O&M offset approximately $100 million of incremental wind O&M. We are continuing to prudently invest in appropriate areas and remain committed to taking costs out of the business through ongoing improvements in processes and technology.

Deliver a Competitive Total Return to Investors and Maintain Strong Investment Grade Credit Rating

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

CONSISTENT **DELIVERY**

TRANSPARENT **GROWTH**

LEADING **ESG PROFILE**

~8-10% Total Shareholder Return	
5-7% EPS Growth	~2.5% Dividend Yield
5-7% Dividend CAGR	60-70% Payout Ratio

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

GAAP and ongoing earnings have grown 5.6% and 6.1%, respectively, annually since 2005 and our dividend grew 6.3% annually from 2013-2020. 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. Our current ratings are consistent with this objective.

Environmental, Social and Governance Leadership

Sustainability is embedded in Xcel Energy's strategy and our values:

Connected Committed Safe Trustworthy

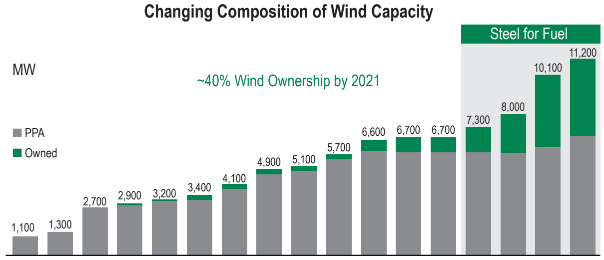
We are retiring coal plants, adding renewables, exploring new technologies and helping to electrify other sectors, while keeping customer bills low. Xcel Energy has demonstrated leadership in mitigating climate, operational and financial risks, while remaining committed to customers, employees and communities.

Environmental

Xcel Energy was the first major U.S. utility to establish a carbon-free vision, targeting 100% carbon-free electricity by 2050 and an 80% carbon reduction by 2030 (from 2005 levels). Our plans to achieve 80% carbon reduction are aligned with targets of the Paris Accord, as validated by a lead author for the Intergovernmental Panel on Climate Change.

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. We have been the number one provider of wind to customers for 12 of the past 15 years. Our wind capacity is expected to reach 11,000 MW by the end of 2021, including nearly 4,500 MW of owned wind.

Changing Composition of Wind Capacity



As Xcel Energy transitions to cleaner sources, we expect to achieve a 70% reduction in water consumed in electric generation by 2030 (from 2005 levels). Through 2020, we reduced our water consumption 34% (from 2005 levels).

Social

Community

We work to foster economic sustainability and continued affordability by partnering with communities, policymakers and customers to build facilities, foster job growth and attract new businesses. In 2020, Xcel Energy completed 20 economic development projects across our service territory. Additionally, 71% of Xcel Energy's supply chain spend was local.

In addition to our annual giving, in 2020 Xcel Energy further supported our communities by committing the net gain of nearly $20 million from our Mankato plant sale to short and long-term corporate giving.

We work to mitigate the impacts of early plant retirements on our employees and community, consistent with our Principles for a Responsible Transition. We provide advanced notice, offer retraining and relocation opportunities and have had no layoffs as a result of plant retirements. We also seek to make investments in the communities in which our coal plants are being shut down to offset the economic impact.

Safety

Safety is embedded in our values and governance practices, and Xcel Energy is focused on preventing life-altering injuries. All employees have "stop work authority" to keep each other, our customers and the public safe. Through our Safety Always approach, employees are encouraged to share experiences and learn from events to help protect themselves, their coworkers and the public.

Human Capital Management

Xcel Energy's success depends on our ability to actively implement programs to attract, hire, develop and retain skilled employees. Our workforce strategy is designed to put the best talent in place, create a culture that motivates employees to lead the way in achieving our clean energy goals and deliver an exceptional customer experience.

Xcel Energy has implemented a strategic, data-driven approach to workforce and succession planning, which includes best practices in learning and development. Additionally, Xcel Energy partners with educational and community organizations to attract and hire diverse employees who reflect the communities we serve. Also, hiring veterans is a key focus of our workforce strategy, with approximately 10% of employees having served in the military. Xcel Energy offers its employees a competitive benefits package which includes: performance-based compensation, healthcare benefits, recognition programs and an employee development program that emphasizes ongoing coaching.

Xcel Energy views diversity, equity and inclusion as an integral part of who we are, how we operate and how we see our future. We are committed to an inclusive culture where diversity is celebrated and employees are treated equitably. Our senior leadership team leads by example, fostering an inclusive work environment, which recognizes the need for crucial conversations on diversity. Additionally, Xcel Energy supports an inclusive environment by offering company-wide trainings on topics addressing microinequities and unconscious bias. We hold ourselves accountable and measure our progress through corporate scorecard metrics that include, among other things, employee feedback in our engagement survey Inclusion Index.

In 2020, Xcel Energy received the following recognitions:

Xcel Energy has publicly confirmed our commitment to the advancement and protection of human rights throughout our operations, consistent with U.S. human rights laws and the general principles set forth in the International Labour Organization Conventions. Xcel Energy requires annual Code of Conduct training for all employees and members of the Board of Directors. Xcel Energy does not tolerate discrimination, violations of our Code of Conduct or other unacceptable behaviors. We offer employees multiple avenues to raise concerns or report wrong-doing and do not permit any retaliation for doing so.

We respect employees' freedom of association and their right to collectively organize. As of Dec. 31, 2020, Xcel Energy's employees were as follows:

	Employees Covered by Collective Bargaining Agreements	Total Full-Time Employees
NSP-Minnesota	2,033	3,144
NSP-Wisconsin	394	540
PSCo	1,882	2,378
SPS	769	1,141
XES	—	4,164
Total	5,078	11,367

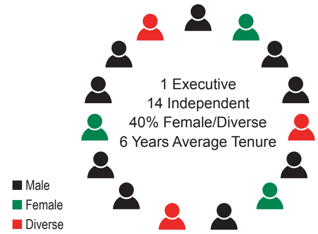
Our workforce demographics as of December 2020 were as follows:

	Female	Ethnically Diverse
Board of Directors	20%	20%
CEO direct reports	38%	13%
Management	22%	10%
Employees	23%	16%
New hires	33%	22%
Interns (hired throughout 2020)	33%	28%

Governance

For decades, Xcel Energy has fostered a culture of compliance and ethical conduct. Our Code of Conduct serves as the foundation that all employees, contractors and the Board of Directors are expected to follow, along with corporate policies that establish rules and guidelines in areas such as safety, environmental leadership, diversity, community giving and political contributions.

Xcel Energy has a diverse and qualified Board of Directors, with eight members elected within the past five years.



Accountability and Incentive

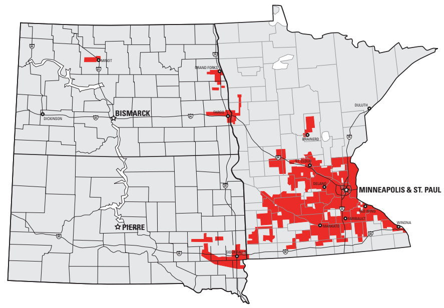
We consistently set aggressive goals and hold ourselves accountable to our customers, communities and investors. Xcel Energy instituted Board of Directors oversight of environmental performance in 2000 and was among the first U.S. utilities to tie carbon reduction directly to executive compensation over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

In 2020, 60% of annual incentive pay was tied to safety and system reliability. In 2021, we added an incentive-based metric to reinforce our commitment to diversity and inclusion. Xcel Energy has clear Board of Directors committee oversight for safety and our human capital strategy, including diversity and inclusion initiatives.

Utility Subsidiaries

NSP-Minnesota

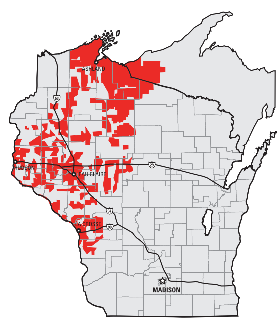
Electric customers	1.5 million
Natural gas customers	0.6 million
Consolidated earnings contribution	35% to 45%
Total assets	$21.1 billion
Rate Base (estimated)	$12.4 billion
ROE (net income / average stockholder's equity)	9.20%
Electric generating capacity	8,137 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	33,660 miles
Electric distribution lines (conductor miles)	80,508 miles
Natural gas transmission lines	80 miles
Natural gas distribution lines	10,629 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

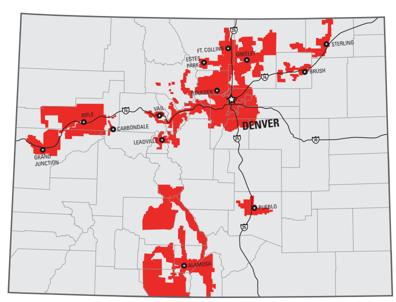
Electric customers	0.3 million
Natural gas customers	0.1 million
Consolidated earnings contribution	5% to 10%
Total assets	$2.9 billion
Rate Base (estimated)	$1.8 billion
ROE (net income / average stockholder's equity)	10.52%
Electric generating capacity	548 MW
Gas storage capacity	3.8 Bcf
Electric transmission lines (conductor miles)	12,288 miles
Electric distribution lines (conductor miles)	27,611 miles
Natural gas transmission lines	3 miles
Natural gas distribution lines	2,492 miles



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

PSCo

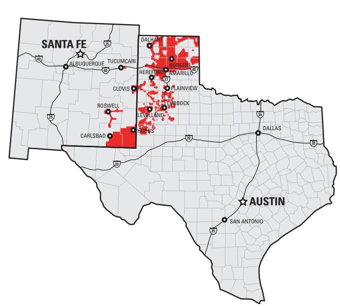
Electric customers	1.5 million
Natural gas customers	1.4 million
Consolidated earnings contribution	35% to 45%
Total assets	$20.4 billion
Rate Base (estimated)	$13.3 billion
ROE (net income / average stockholder's equity)	8.06%
Electric generating capacity	6,223 MW
Gas storage capacity	32.5 Bcf
Electric transmission lines (conductor miles)	24,386 miles
Electric distribution lines (conductor miles)	78,483 miles
Natural gas transmission lines	2,058 miles
Natural gas distribution lines	22,815 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
Consolidated earnings contribution	15% to 20%
Total assets	$8.9 billion
Rate Base (estimated)	$5.4 billion
ROE (net income / average stockholder's equity)	9.54%
Electric generating capacity	5,232 MW
Electric transmission lines (conductor miles)	40,019 miles
Electric distribution lines (conductor miles)	21,984 miles



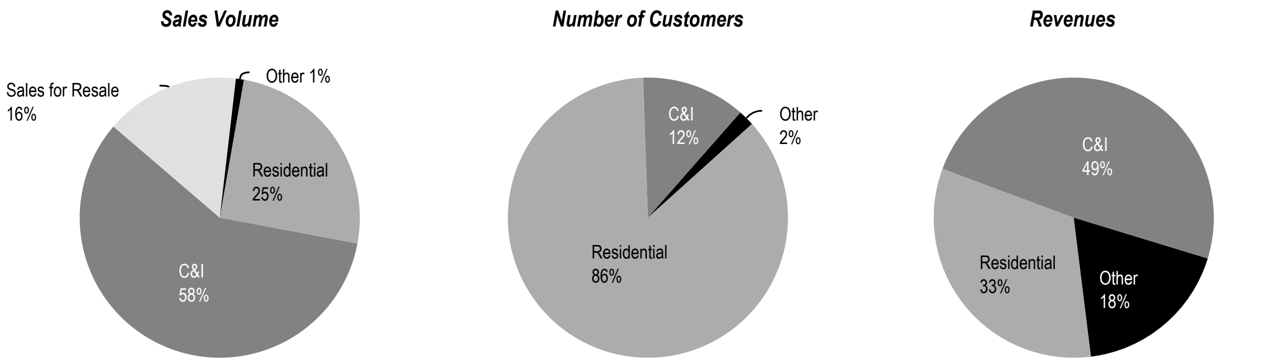
SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.

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 104,731 (millions of KWh), 3.7 million customers and electric revenues of $9,802 (millions of dollars) for 2020.

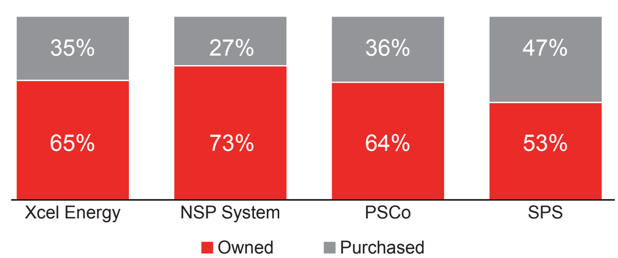


Sales/Revenue Statistics [a]

	2020	2019
KWh sales per retail customer	23,910	24,712
Revenue per retail customer	$ 2,199	$ 2,244
Residential revenue per KWh	12.12 ¢	11.97 ¢
Large C&I revenue per KWh	5.78 ¢	5.96 ¢
Small C&I revenue per KWh	9.56 ¢	9.43 ¢
Total retail revenue per KWh	9.20 ¢	9.08 ¢

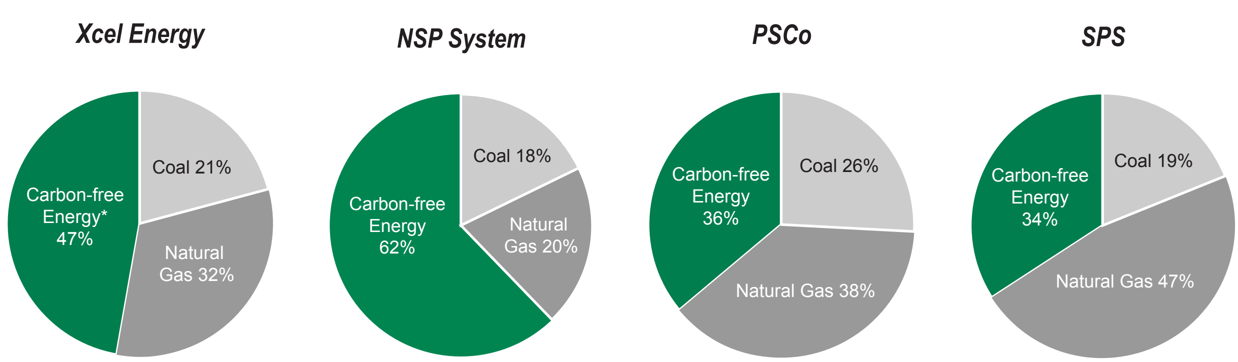
(a) See Note 6 to the consolidated financial statements for further information.

Owned and Purchased Energy Generation — 2020



Electric Energy Sources

Total electric generation by source (including energy market purchases) for the year ended Dec. 31, 2020:



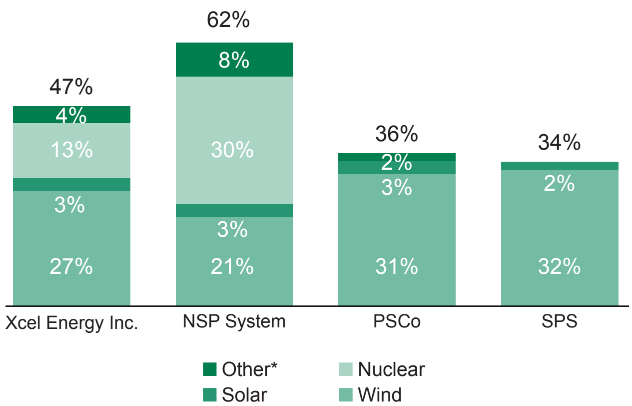
* Distributed generation from the Solar*Rewards® program is not included (approximately 675 million KWh for 2020).

Carbon-Free Energy

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, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Carbon-free energy as a percentage of total energy for 2020:



* Includes biomass and hydroelectric.

Wind

Owned — Owned and operated wind farms with corresponding capacity:

	2020		2019	
Utility Subsidiary	Wind Farms	Capacity [a]	Wind Farms	Capacity [b]
NSP System	11	1,540 MW	7	1,079 MW
PSCo	2	1,059 MW	1	582 MW
SPS	2	967 MW	1	460 MW
Total	15	3,566 MW	9	2,121 MW

(a) Summer 2020 net dependable capacity.

(b) Summer 2019 net dependable capacity.

PPAs — Number of PPAs with capacity range:

	2020		2019	
Utility Subsidiary	PPAs	Range	PPAs	Range
NSP System	129	1 MW — 206 MW	131	1 MW — 206 MW
PSCo	17	23 MW — 301 MW	20	2 MW — 301 MW
SPS	18	1 MW — 250MW	18	1 MW — 250 MW

Capacity — Wind capacity:

Utility Subsidiary	2020	2019
NSP System	3,348 MW	2,767 MW
PSCo	4,085 MW	3,145 MW
SPS	2,535 MW	2,027 MW

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

Utility Subsidiary	2020	2019
NSP System	$ 23	$ 35
PSCo	35	47
SPS	17	—

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

Utility Subsidiary	2020	2019
NSP System	$ 38	$ 41
PSCo	40	41
SPS	26	25

Wind Development

Xcel Energy placed approximately 1,450 MW of owned wind and approximately 700 MW of PPAs into service during 2020:

Project	Utility Subsidiary	Capacity
Blazing Star 1	NSP-Minnesota	200 MW [a][b]
Crowned Ridge 2	NSP-Minnesota	192 MW [a][b]
Community Wind North	NSP-Minnesota	26 MW [a][b]
Jeffers	NSP-Minnesota	43 MW [a][b]
Cheyenne Ridge	PSCo	477 MW [a][b]
Sagamore	SPS	507 MW [a][b]
Various PPAs	Various	~700 MW [c]

(a) Summer 2020 net dependable capacity.

(b) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

(c) Based on contracted capacity.

Xcel Energy currently has approximately 1,450 MW of owned wind under development or construction. In addition, Xcel Energy expects to add approximately 450 MW of planned PPAs.

Project	Utility Subsidiary	Capacity	Estimated Completion
Dakota Range	NSP-Minnesota	300 MW	2021
Freeborn	NSP-Minnesota	200 MW	2021
Blazing Star 2	NSP-Minnesota	200 MW	2021
Nobles	NSP-Minnesota	200 MW	2022
Pleasant Valley	NSP-Minnesota	200 MW	2024
Border Winds	NSP-Minnesota	150 MW	2024
Grand Meadow	NSP-Minnesota	100 MW	2023
Mower	NSP-Minnesota	99 MW	2021
Various PPAs	Various	~450 MW	2021

Solar

Solar PPA(s):

Type	Utility Subsidiary	Capacity
Distributed Generation	NSP System	899 MW
Utility-Scale	NSP System	268 MW
Distributed Generation	PSCo	643 MW
Utility-Scale	PSCo	306 MW
Distributed Generation	SPS	11 MW
Utility-Scale	SPS	190 MW
Total		2,317 MW

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

Utility Subsidiary	2020	2019
NSP System	$ 90	$ 81
PSCo	89	89
SPS	59	56

Solar Development

In October 2020, Xcel Energy filed a request with the PSCW to purchase a 74 MW, $100 million solar array in Pierce County, WI. A PSCW decision is expected in the third quarter of 2021. Also, as part of the Minnesota Recovery and Relief Recovery docket, NSP-Minnesota, proposed the addition of 460 MW of solar facilities with an expected $550 million incremental investment. An MPUC decision is expected in the second half of 2021.

Additionally, Xcel Energy projects approximately 3,500 MW of solar through 2034 in our Minnesota resource plan and will be addressing solar energy within its upcoming Colorado resource plan.

Nuclear

Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2020 net summer dependable capacity that serves the NSP-System. Our nuclear fleet has become one of the safest and well-run in the nation, as rated by both the NRC and INPO. Xcel Energy secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. We use varying contract lengths as well as multiple producers for uranium concentrates, conversion services and enrichment services to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

Nuclear Fuel Cost

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

Utility Subsidiary	Nuclear	
NSP System	**Cost**	**Percent**
2020	$ 0.80	51 %
2019	0.81	45

Other Carbon-Free Energy

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

See Item 2 — Properties for further information.

Fossil Fuel Energy

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

Coal

Xcel Energy owns and operates coal units with approximately 6,500 MW of total 2020 net summer dependable capacity.

Approved and proposed early coal plant retirements:

Approved / Authorized			
Year	**Utility Subsidiary**	**Plant Unit**	**Capacity**
2022	PSCo	Comanche 1	325 MW
2023	NSP-Minnesota	Sherco 2	682 MW
2024	SPS	Harrington [(a)]	1,018 MW
2025	PSCo	Comanche 2	335 MW
2025	PSCo	Craig 1	42 MW [(b)]
2026	NSP-Minnesota	Sherco 1	680 MW
2028	PSCo	Craig 2	40 MW [(b)]

(a) Reflects expected conversion from coal to natural gas following the TCEQ order that Harrington cease use of coal fuel by Jan. 1, 2025, pending PUCT and NMPRC review.

(b) Based on Xcel Energy's ownership interest.

Proposed			
Year	**Utility Subsidiary**	**Plant Unit**	**Capacity**
2027	PSCo	Hayden 2	98 MW [(a)]
2028	PSCo	Hayden 1	135 MW [(b)]
2028	NSP-Minnesota	A.S. King	511 MW
2030	NSP-Minnesota	Sherco 3	517 MW [(c)]
2032	SPS	Tolk 1	532 MW
2032	SPS	Tolk 2	535 MW

(a) Based on PSCo's ownership of 37% of Unit 2.

(b) Based on PSCo's ownership of 76% of Unit 1.

(c) Based on Xcel Energy's ownership interest.

Plans for our remaining Colorado coal fleet will be outlined when PSCo submits its 2021 resource plan, which is expected to be filed in March 2021.

Coal Fuel Cost

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

	Coal [(a)]	
Utility Subsidiary	**Cost**	**Percent**
NSP System		
2020	$ 1.97	31 %
2019	2.02	36
PSCo		
2020	1.41	51
2019	1.45	55
SPS		
2020	2.28	40
2019	2.19	45

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

Natural Gas

Xcel Energy has 22 natural gas plants with approximately 7,900 MW of total 2020 net summer dependable capacity.

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

Natural Gas Cost

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

	Natural Gas	
Utility Subsidiary	**Cost**	**Percent**
NSP System		
2020	$ 2.67	17 %
2019	3.09	19
PSCo		
2020	3.01	49
2019	3.27	45
SPS		
2020	1.43	60
2019	1.14	55

Capacity and Demand

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

	System Peak Demand (in MW)			
	2020		2019	
NSP System	8,571	July 8	8,774	July 19
PSCo	6,899	Aug. 17	7,111	July 19
SPS	4,195	July 14	4,261	Aug. 5

Transmission

Transmission lines deliver electricity at higher voltage and over longer distances from power sources to transmission substations closer to homes and businesses. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy. Xcel Energy owns more than 20,000 miles of transmission lines, serving 22,000 MW of customer load.

Transmission projects completed in 2020 include:

Project	Utility Subsidiary	Miles	Size
Maple River-Red River	NSP-Minnesota	4	115 KV
Glenwood Douglas	NSP-Minnesota	20	69 KV
Prentice to Structure	NSP-Wisconsin	8	115 KV
Lufkin to Naples	NSP-Wisconsin	13	69 KV
Belgrade to Ironwood	NSP-Wisconsin	13	35 KV
Cornucopia to Bayfield Phase 2	NSP-Wisconsin	5	35 KV
Pawnee-Daniels Park	PSCo	113	345 KV
Cheyenne Ridge	PSCo	73	345 KV
TUCO-Yoakum Co.	SPS	107	345 KV
Eddy Co-Kiowa	SPS	34	345 KV
Mustang-Seminole	SPS	20	115 KV
Loving South-Phantom	SPS	21	115 KV

Notable upcoming projects:

Project	Utility Subsidiary	Miles	Size	Completion Date
Hibbing Taconite Relocation	NSP-Minnesota	3	500 KV	2021
Huntley-Wilmarth	NSP-Minnesota	50	345 KV	2021
Helena Scott County	NSP-Minnesota	16	345 KV	2021
Baytown to Long Lake	NSP-Minnesota	9	115 KV	2022
Centerville to Lincoln County	NSP-Minnesota	14	69 KV	2021
Turtle Lake Almena	NSP-Wisconsin	4	69 KV	2021
Bayfield Second Circuit	NSP-Wisconsin	19	35 KV	2022
Roadrunner-China Draw	SPS	41	345 KV	2021

See Item 2 - Properties for further information.

Distribution

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

To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure. Over the five year project, Xcel Energy plans to invest approximately $1.8 billion implementing new network infrastructure, smart meters, advanced software, equipment sensors and related data analytics capabilities.

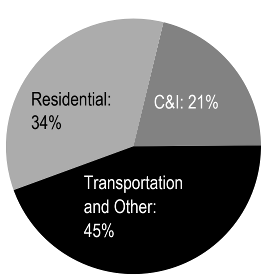
These investments will further improve reliability and reduce outage restoration times for our customers, while at the same time enabling new options and opportunities for increased efficiency savings. The new capabilities will also enable integration of battery storage and other distributed energy resources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

See Item 2 - Properties for further information.

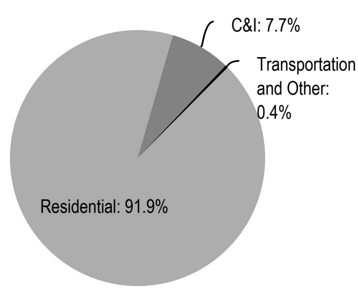
Natural Gas Operations

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 444,340 (thousands of MMBtu), 2.1 million customers and natural gas revenues of $1,636 (millions of dollars) for 2020.

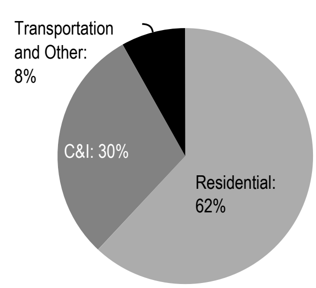
Deliveries



Number of Customers



Revenues



Sales/Revenue Statistics [(a)]

	2020	2019
MMBtu sales per retail customer	118.13	129.31
Revenue per retail customer	$ 720.42	$ 851.94
Residential revenue per MMBtu	6.64	7.14
C&I revenue per MMBtu	5.22	5.73
Transportation and other revenue per MMBtu	0.67	0.57

(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:

	2020		2019	
Utility Subsidiary	**MMBtu**	**Date**	**MMBtu**	**Date**
NSP-Minnesota	871,921	Jan. 16	897,615	Feb. 25
NSP-Wisconsin	150,320	Dec. 24	166,009	Jan. 30
PSCo	1,931,888	Feb. 4	2,139,420	March 3

Natural Gas Supply and Cost

Xcel Energy seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which increase flexibility, decrease interruption and financial risks and economic 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	2020	2019
NSP-Minnesota	$ 3.32	$ 3.71
NSP-Wisconsin	3.08	3.49
PSCo	2.52	2.95

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. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, 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.

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 construction and operation of certain new electric transmission facilities. State utility commissions have also created resource planning programs that promote competition for electric generation resources used to provide service to retail customers.

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

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

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous 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 operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of MGP and other sites if it is determined that prior compliance efforts are not sufficient.

Xcel Energy must comply with emission levels in Minnesota, Texas and Wisconsin that may require the purchase of emission allowances. The Denver North Front Range Non-attainment Area does not meet either the 2008 or 2015 ozone NAAQS. Colorado will continue to consider further reductions available in the non-attainment area as it develops plans to meet ozone standards. Gas plants which operate in PSCo's non-attainment area may be required to improve or add controls, implement further work practices and/or enhanced emissions monitoring as part of future Colorado state plans.

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

In July 2019, the EPA adopted the Affordable Clean Energy rule, which required states to develop plans by 2022 for GHG reductions from coal-fired power plants. In a Jan. 19, 2021 decision, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision, if not successfully appealed or reconsidered, would allow the EPA to proceed with alternate regulation of coal-fired power plants, either reviving the Clean Power Plan or proposing additional regulation. It is too early to predict an outcome, but new rules could require substantial additional investment, even in plants slated for retirement. Xcel Energy believes, based on prior state commission practices, the cost of these initiatives or replacement generation would be recoverable through rates.

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

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

In 2020, Xcel Energy estimates that it reduced carbon emissions associated with electric generating resources, both owned and under PPAs, used to serve its customers by approximately 51% from 2005 levels.

Environmental Costs

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

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

- $400 million in 2020.
- $345 million in 2019.
- $335 million in 2018.

Average annual expense of approximately $465 million from 2021 – 2025 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:

- $30 million in 2020.
- $30 million in 2019.
- $50 million in 2018.

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
Ben Fowke	62	Chairman of the Board of Directors, Chief Executive Officer and Director, Xcel Energy Inc.	August 2011 — Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	January 2015 — Present
		President, Xcel Energy Inc.	August 2011 — March 2020
Robert C. Frenzel	50	President and Chief Operating Officer, Xcel Energy Inc.	March 2020 — Present
		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	54	Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 — Present
		Senior Vice President and Shared Services Executive, Bank of America, an institutional investment bank and financial services company	October 2015 — May 2018
Christopher B. Clark	54	President and Director, NSP-Minnesota	January 2015 — Present
Darla Figoli	58	Executive Vice President, Human Resources & Employee Services, Chief Human Resources Officer, Xcel Energy Inc.	June 2020 — Present
		Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer, Xcel Energy Inc.	May 2018 — June 2020
		Senior Vice President, Human Resources and Employee Services, Xcel Energy Inc.	May 2015 — May 2018
David T. Hudson	60	President and Director, SPS	January 2015 — Present
Alice Jackson	42	President and Director, PSCo	May 2018 — Present
		Area Vice President, Strategic Revenue Initiatives, Xcel Energy Services Inc.	November 2016 — May 2018
		Regional Vice President, Rates and Regulatory Affairs, PSCo	November 2013 — November 2016
Timothy O'Connor	61	Executive Vice President, Chief Generation Officer, Xcel Energy Inc.	March 2020 — Present
		Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc	February 2013 — March 2020
Frank Prager	58	Senior Vice President, Strategy, Planning and External Affairs, Xcel Energy Inc.	March 2020 — Present
		Vice President, Policy and Federal Affairs, Xcel Energy Services Inc.	January 2015 — March 2020
Amanda Rome	40	Executive Vice President, General Counsel, Xcel Energy Inc.	June 2020 — Present
		Vice President and Deputy General Counsel, Xcel Energy Services Inc.	October 2019 — June 2020
		Managing Attorney, Xcel Energy Services Inc.	July 2018 — October 2019
		Rotational Position, Xcel Energy Services Inc.	January 2018 — July 2018
		Lead Assistant General Counsel, Xcel Energy Services Inc.	July 2015 — January 2018
Jeffrey S. Savage	49	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 — Present
Mark E. Stoering	60	President and Director, NSP-Wisconsin	January 2015 — Present
Brian J. Van Abel	39	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. 17, 2021.
(c) In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including TCEH the parent company of Luminant, filed a voluntary bankruptcy petition under Chapter 11 of the United States Bankruptcy Code. TCEH 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. 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.

Oversight of Risk and Related Processes

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

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

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

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

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

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

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

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

Risks Associated with Our Business

Operational Risks

Our natural gas and electric 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. 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.

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

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

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

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

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

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

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

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure, which increases exposure to technology obsolescence. Additionally, evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may put pressure on our ability to recover capital investments in natural gas generation and delivery.

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. Additionally, multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

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

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

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

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

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

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

Due to the inherent uncertainty involved in price movements and potential deviation from historical pricing, Xcel Energy is unable to fully assure that its risk management programs and procedures would be effective to protect against all significant adverse market deviations. In addition, Xcel Energy cannot fully assure that its controls will be effective against all potential risks, including, without limitation, employee misconduct. If such controls 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.

Specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets. Xcel Energy's business strategy is dependent on our ability to recruit, retain and motivate employees. There is competition and a tightening market for skilled employees. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

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

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

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

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

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

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

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

Financial Risks

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

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

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

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

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

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

In a continued low interest rate environment, there has been increased downward pressure on allowed ROE. Conversely, higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers.

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

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

We cannot be assured that our current credit ratings or our subsidiaries' ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, 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 and could impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require posting of collateral or settlement if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

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

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

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the economy and unemployment rates. Credit risk also includes the risk that counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

Xcel Energy may have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, (e.g. California Independent System Operator, SPP, PJM Interconnection, LLC, MISO and Electric Reliability Council of Texas), in which any credit losses are socialized to all market participants. We have additional indirect credit exposure to financial institutions from letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

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

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

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

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

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

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

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

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

Federal tax law may significantly impact our business.

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

Macroeconomic Risks

Economic conditions impact our business.

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

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

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

The global outbreak of COVID-19 is impacting countries, communities, supply chains and markets. A high degree of uncertainty continues to exist regarding the pandemic, the duration and magnitude of business restrictions, re-shut downs, if any, and the level and pace of economic recovery. While we are implementing contingency plans, there are no guarantees these plans will be sufficient to offset the impact of COVID-19.

Although the impact of the pandemic to the 2020 results was largely mitigated due to management's actions, we cannot ultimately predict whether it will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact of the virus on the health of our employees, our supply chain or our ability to recover higher costs associated with managing through the pandemic. The impact of COVID-19 may exacerbate other risks discussed herein, which could have a material effect on us. The situation is evolving and additional impacts may arise.

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

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

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

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

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

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

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

Xcel Energy participates in grid security and emergency response exercises (GridEx). These efforts, led by the NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

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

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

Xcel Energy's generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals.

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

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

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

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

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

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

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

Public Policy Risks

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

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

In 2015, the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2º Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5º Celsius. The Biden Administration will establish a new nationally determined contribution for the United States. The Paris Agreement could result in future additional GHG reductions in the United States. In addition, the Biden Administration has announced plans to implement new climate change programs, including potential regulation of GHG emissions targeting the utility industry.

The Biden Administration has also announced a one year suspension of new oil and natural gas drilling on federal lands to allow for a review of oil and gas leasing regulations. The form of these regulations is uncertain, but, depending on the requirements imposed in the short and long term, they could impose substantial costs on our oil and gas customers or result in substantial increases to the cost of fuel we use in our electricity and gas businesses.

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

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

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

Increased risks of regulatory penalties could negatively impact our business.

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

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

Environmental Risks

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

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

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

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

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

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

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

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

Climate change may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

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

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

While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of power plants and increase the cost for energy. 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	Fuel	Installed	MW [(a)]
Steam:			
A.S. King-Bayport, MN, 1 Unit [(f)]	Coal	1968	511
Sherco-Becker, MN [(e)]			
Unit 1	Coal	1976	680
Unit 2	Coal	1977	682
Unit 3	Coal	1987	517 [(b)]
Monticello, MN, 1 Unit	Nuclear	1971	617
PI-Welch, MN			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Various locations, 4 Units	Wood/Refuse	Various	36 [(c)]
Combustion Turbine:			
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2018	494
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	447
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	252
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454
Various locations, 7 Units	Natural Gas	Various	10
Wind:			
Border-Rolette County, ND, 75 Units	Wind	2015	148 [(d)]
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190 [(d)]
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150 [(d)]
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	99 [(d)]
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99 [(d)]
Nobles-Nobles County, MN, 134 Units	Wind	2010	197 [(d)]
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196 [(d)]
Blazing Star 1-Lincoln County, MN, 100 Units	Wind	2020	200 [(d)]
Crowned Ridge 2-Grant County, SD, 88 Units	Wind	2020	192 [(d)]
Community Wind North-Lincoln County, MN, 12 Units	Wind	2020	26 [(d)]
Jeffers-Cottonwood County, MN, 20 Units	Wind	2020	43 [(d)]
		Total	8,137

(a) Summer 2020 net dependable capacity.

(b) Based on NSP-Minnesota's ownership of 59%.

(c) Refuse-derived fuel is made from municipal solid waste.

(d) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

(e) A.S. King is expected to be retired early in 2028.

(f) Sherco Unit 1, 2, and 3 are expected to be retired early in 2026, 2023 and 2030, respectively.

NSP-Wisconsin

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

(a) Summer 2020 net dependable capacity.
(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Comanche-Pueblo, CO [(b)]			
Unit 1	Coal	1973	325
Unit 2	Coal	1975	335
Unit 3	Coal	2010	500 [(c)]
Craig-Craig, CO, 2 Units [(d)]	Coal	1979 - 1980	82 [(e)]
Hayden-Hayden, CO, 2 Units [(h)]	Coal	1965 - 1976	233 [(f)]
Pawnee-Brush, CO, 1 Unit	Coal	1981	505
Cherokee-Denver, CO, 1 Unit	Natural Gas	1968	310
Combustion Turbine:			
Blue Spruce-Aurora, CO, 2 Units	Natural Gas	2003	264
Cherokee-Denver, CO, 3 Units	Natural Gas	2015	576
Fort St. Vrain-Platteville, CO, 6 Units	Natural Gas	1972 - 2009	968
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580
Various locations, 8 Units	Natural Gas	Various	251
Hydro:			
Cabin Creek-Georgetown, CO			
Pumped Storage, 2 Units	Hydro	1967	210
Various locations, 8 Units	Hydro	Various	25
Wind:			
Rush Creek, CO, 300 units	Wind	2018	582 [(g)]
Cheyenne Ridge, CO, 229 units	Wind	2020	477 [(g)]
		Total	6,223

(a) Summer 2020 net dependable capacity.
(b) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in 2022 and 2025, respectively.
(c) Based on PSCo's ownership of 67%.
(d) Craig Unit 1 and 2 are expected to be retired early in 2025 and 2028, respectively.
(e) Based on PSCo's ownership of 10%.
(f) Based on PSCo's ownership of 76% of Unit 1 and 37% of Unit 2.
(g) Values disclosed are the generation levels at the point-of-interconnection. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(h) Hayden Unit 1 and 2 are expected to be retired in 2028 and 2027, respectively.

SPS

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	225
Harrington-Amarillo, TX, 3 Units [(b)]	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	298
Tolk-Muleshoe, TX, 2 Units [(d)]	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	207
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units	Wind	2019	460 [(c)]
Sagamore-Dora, NM, 240 Units	Wind	2020	507 [(c)]
		Total	5,232

(a) Summer 2020 net dependable capacity.
(b) Harrington is expected to be converted to natural gas by the end of 2024.
(c) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero)
(d) Tolk Unit 1 and 2 are expected to be retired in 2032.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2020:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Transmission				
500 KV	2,918	—	—	—
345 KV	13,151	3,337	5,389	11,019
230 KV	2,301	—	12,131	9,795
161 KV	674	1,823	—	—
138 KV	—	—	92	—
115 KV	8,060	1,822	5,092	14,830
Less than 115 KV	6,556	5,306	1,682	4,375
Total Transmission	33,660	12,288	24,386	40,019
Distribution				
Less than 115 KV	80,508	27,611	78,483	21,984
Total	**114,168**	**39,899**	**102,869**	**62,003**

Electric utility transmission and distribution substations at Dec. 31, 2020:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	352	204	236	457

Natural gas utility mains at Dec. 31, 2020:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	80	3	2,058	20	11
Distribution	10,629	2,492	22,815	—	—

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 financial statements. Unless otherwise required by GAAP, legal fees are 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.

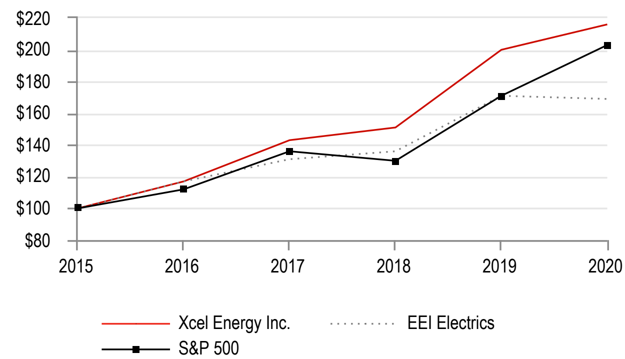
Stock Data

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. 12, 2021 was approximately 52,689.

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, 2015 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, 2020, 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 — SELECTED FINANCIAL DATA

Selected financial data for Xcel Energy related to the five most recent years ended Dec. 31:

(Millions of Dollars, Millions of Shares, Except Per Share Data)	2020	2019	2018	2017	2016
Operating revenues	$ 11,526	$ 11,529	$ 11,537	$ 11,404	$ 11,107
Operating expenses [(a)]	9,410	9,425	9,572	9,181	8,867
Net income	1,473	1,372	1,261	1,148	1,123
Earnings available to common shareholders	1,473	1,372	1,261	1,148	1,123
Diluted earnings per common share	2.79	2.64	2.47	2.25	2.21
Financial information					
Dividends declared per common share	1.72	1.62	1.52	1.44	1.36
Total assets	53,957	50,448	45,987	43,030	41,155
Long-term debt [(b)]	19,645	17,407	15,803	14,520	14,195

(a) As a result of adopting ASU No. 2017-07 (Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715), $33 million and $26 million of pension costs were retrospectively reclassified from O&M expenses to other income, net on the consolidated statements of income for the years ended Dec. 31, 2017 and Dec. 31, 2016, respectively.

(b) As a result of adopting Leases, Topic 842, finance lease obligations of $77 million are included in other noncurrent liabilities on the consolidated balance sheet at Dec. 31, 2019. These obligations were included in long-term debt prior to 2019.

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, electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Ongoing ROE

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

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues. Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

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

GAAP diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method. Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Ongoing diluted EPS 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, 2020 and 2019, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

Diluted Earnings (Loss) Per Share	2020 GAAP and Ongoing Diluted EPS	2019 GAAP and Ongoing Diluted EPS
NSP-Minnesota	$ 1.12	$ 1.04
PSCo	1.11	1.11
SPS	0.56	0.51
NSP-Wisconsin	0.20	0.15
Equity earnings of unconsolidated subsidiaries	0.05	0.05
Regulated utility [(a)]	3.04	2.86
Xcel Energy Inc. and Other	(0.25)	(0.22)
Total [(a)]	$ 2.79	$ 2.64

(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.

2020 Comparison with 2019

Xcel Energy — GAAP and ongoing earnings increased $0.15 per share, primarily reflecting higher electric margin (largely due to regulatory outcomes which recover capital investment), higher AFUDC and lower O&M expenses, which offset increased depreciation, interest expense and declining sales primarily due to the impacts of COVID-19.

NSP-Minnesota — Earnings increased $0.08 per share for 2020, reflecting higher electric margin (riders, wholesale transmission revenue and a sales true-up mechanism, which recovers lower sales due to COVID-19) and lower O&M expenses, partially offset by increased depreciation and lower natural gas margin.

PSCo — Earnings were flat for 2020, reflecting higher electric margin (wholesale transmission revenue and regulatory outcomes offset lower sales due to COVID-19), increased AFUDC and higher natural gas margin, offset by additional depreciation and taxes (other than income taxes).

SPS — Earnings increased $0.05 per share for 2020, reflecting higher electric margin (wholesale transmission revenue and regulatory outcomes offset lower sales due to COVID-19) and lower O&M expenses, partially offset by increased depreciation, interest expense and taxes (other than income taxes).

NSP-Wisconsin — Earnings increased $0.05 per share for 2020, reflecting higher electric margin (regulatory outcomes offset lower sales due to COVID-19) and lower O&M expenses, partially offset by increased depreciation and lower natural gas margin.

Xcel Energy Inc. and Other — Primarily includes financing costs at the holding company.

Changes in Diluted EPS

Components significantly contributing to changes in EPS:

2020 vs. 2019		
Diluted Earnings (Loss) Per Share		**Dec. 31**
GAAP and ongoing diluted EPS - 2019	**$**	**2.64**
Components of change — 2020 vs. 2019		
Higher electric margins [(a)]		0.32
Lower ETR [(b)]		0.22
Higher AFUDC		0.08
Changes in O&M		0.02
Higher depreciation and amortization		(0.26)
Higher interest		(0.10)
Higher taxes (other than income taxes)		(0.06)
Changes in natural gas margins		(0.01)
Other (net)		(0.06)
GAAP and ongoing diluted EPS — 2020	**$**	**2.79**

(a) Change in electric margin was negatively impacted by reductions in sales and demand due to COVID-19 and is detailed below. Sales decline excludes weather impact, net of decoupling/sales true-up and reduction in demand revenue is net of sales true-up.

Diluted Earnings (Loss) Per Share		Twelve Months Ended Dec. 31
Electric margin (excluding reductions in sales and demand)	$	0.41
Reductions in sales and demand		(0.09)
Higher electric margins	$	0.32

(b) Includes PTCs and tax reform regulatory amounts, which are primarily offset in electric margin.

ROE for Xcel Energy and its utility subsidiaries:

	2020	2019
ROE	**GAAP and Ongoing ROE**	**GAAP and Ongoing ROE**
NSP-Minnesota	9.20 %	9.31 %
PSCo	8.06	8.69
SPS	9.54	9.71
NSP-Wisconsin	10.52	8.27
Operating Companies	8.87	9.06
Xcel Energy	10.59	10.78

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 to the extent there is not a decoupling or sales true-up mechanism in the state.

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

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

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

	2020 vs. Normal	2019 vs. Normal	2020 vs. 2019
HDD	(3.1)%	10.4 %	(12.0)%
CDD	22.2	5.4	24.8
THI	6.3	(8.8)	18.2

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

	2020 vs. Normal	2019 vs. Normal	2020 vs. 2019
Retail electric	$ 0.090	$ 0.040	$ 0.050
Decoupling and sales true-up	(0.041)	—	(0.041)
Total (excluding decoupling)	$ 0.049	$ 0.040	$ 0.009
Firm natural gas	(0.011)	0.027	(0.038)
Total (adjusted for recovery from decoupling)	$ 0.038	$ 0.067	$ (0.029)

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

	2020 vs. 2019				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Actual [(a)]					
Electric residential	5.8 %	5.0 %	3.6 %	2.4 %	4.9 %
Electric C&I	(4.1)	(7.0)	(3.3)	(4.6)	(5.0)
Total retail electric sales	(1.1)	(3.4)	(2.2)	(2.6)	(2.3)
Firm natural gas sales	(6.8)	(8.3)	*n/a*	(6.4)	(7.2)

	2020 vs. 2019				
	PSCo	**NSP-Minnesota**	**SPS**	**NSP-Wisconsin**	**Xcel Energy**
Weather-normalized [(a)]					
Electric residential	3.8 %	3.7 %	1.6 %	2.6 %	3.3 %
Electric C&I	(4.5)	(7.0)	(3.4)	(4.8)	(5.2)
Total retail electric sales	(1.9)	(3.8)	(2.6)	(2.7)	(2.8)
Firm natural gas sales	0.5	1.9	*n/a*	5.1	1.3

	2020 vs. 2019 (Leap Year Adjusted)				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized [(a)]					
Electric residential	3.6 %	3.4 %	1.3 %	2.3 %	3.1 %
Electric C&I	(4.8)	(7.3)	(3.7)	(5.0)	(5.4)
Total retail electric sales	(2.2)	(4.1)	(2.9)	(2.9)	(3.1)
Firm natural gas sales	0.1	1.4	*n/a*	4.6	0.7

[(a)] Higher residential sales and lower C&I sales were primarily attributable to COVID-19. The increase in residential sales was partially driven by more customers working from home.

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

- PSCo — Residential sales rose based on an increased number of customers and higher use per customer. The decline in C&I sales was primarily due to COVID-19, particularly within the manufacturing and service industries, partially offset by an increase in the energy sector.
- NSP-Minnesota — Residential sales rose based on an increased number of customers and higher use per customer. The decline in C&I sales was primarily due to COVID-19, particularly within the energy, manufacturing and services sectors.
- SPS — Residential sales rose based on an increased number of customers and higher use per customer. The decline in C&I sales was primarily due to COVID-19, particularly within the energy and manufacturing sectors.
- NSP-Wisconsin — Residential sales rose based on an increased number of customers and higher use per customer. The decline in C&I sales was primarily due to COVID-19, particularly within the energy and manufacturing sectors.

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

- Higher natural gas sales reflect an increase in the number of customers combined with higher residential customer use, partially offset by lower C&I customer use.

Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium. However, these fluctuations have minimal impact on margin due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and margin (offset by lower tax expense).

Electric revenues and margin:

(Millions of Dollars)	2020	2019
Electric revenues	$ 9,802	$ 9,575
Electric fuel and purchased power	(3,512)	(3,510)
Electric margin	$ 6,290	$ 6,065

Changes in Electric Margin

(Millions of Dollars)	2020 vs. 2019
Regulatory rate outcomes (Colorado, Wisconsin, Texas and New Mexico) [(a)]	$ 209
Non-fuel riders	74
Wholesale transmission revenue (net)	59
MEC purchased capacity costs	35
Conservation incentive	13
2019 tax reform customer credits - Wisconsin (offset in income tax)	7
Estimated impact of weather (net of decoupling / sales true-up)	7
PTCs flowed back to customers (offset by lower ETR)	(119)
Sales and demand [(b)]	(66)
Other (net)	6
Total increase in electric margin	$ 225

(a) Includes approximately $70 million of revenue and margin due to the Texas rate case outcome, which is largely offset by recognition of previously deferred costs.

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

Natural Gas Margin

Natural gas expense varies with changing sales and cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on margin due to cost recovery mechanisms.

Natural gas revenues and margin:

(Millions of Dollars)	2020	2019
Natural gas revenues	$ 1,636	$ 1,868
Cost of natural gas sold and transported	(689)	(918)
Natural gas margin	$ 947	$ 950

Changes in Natural Gas Margin

(Millions of Dollars)	2020 vs. 2019
Estimated impact of weather	$ (28)
Regulatory rate outcomes (Colorado and Wisconsin)	16
Infrastructure and integrity riders	8
Retail sales growth	2
Other (net)	(1)
Total decrease in natural gas margin	$ (3)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $14 million, or 0.6%, for 2020, largely reflecting management actions to reduce costs to offset the impact of lower sales from COVID-19.

Significant changes are as follows:

(Millions of Dollars)	2020 vs. 2019
Distribution	$ (47)
Generation	(12)
Transmission	(10)
Minnesota payment plan credit program	18
Information technology	14
Employee benefits	12
Texas rate case deferral	8
Other (net)	3
Total decrease in O&M expenses	$ (14)

- Distribution declined due to cost mitigation/continuous improvement efforts and timing of maintenance, partially offset by increased storm impacts.
- Generation was lower from timing of maintenance and overhauls at power plants and cost mitigation/continuous improvement efforts, partially offset by an increase in maintenance expenses from wind expansion.
- Transmission declined due to cost mitigation/continuous improvement initiatives.
- Minnesota payment plan credit program represents a commitment to fund customer programs as agreed to in the NSP-Minnesota rate case stay-out.
- Information technology costs increased due to higher spending on network and other infrastructure costs.
- Employee benefits increased due primarily to postretirement costs and other long-term benefits, partially offset by lower deferred compensation expense.

Depreciation and Amortization — Depreciation and amortization increased $183 million, or 10.4%, year-to-date. The increase was primarily driven by the Hale, Cheyenne Ridge, Foxtail, Blazing Star I, Lake Benton, Sagamore, Crowned Ridge, Community Wind North and Jeffers wind facilities going into service, as well as normal system expansion. In addition, new depreciation rates were implemented in Colorado, New Mexico and Texas in 2020, increasing expense.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $43 million, or 7.6%, year-to-date. The increase was primarily due to higher property taxes in Colorado and Texas (net of deferred amounts).

Other Income (Expense) — Other income (expense) decreased $22 million year-to-date. The decrease was largely due to the performance of rabbi trust investments, primarily offset in O&M expenses.

AFUDC, Equity and Debt — AFUDC increased $43 million year-to-date. The increase was primarily due to various wind projects under construction.

Interest Charges — Interest charges increased $67 million, or 8.7%, year-to-date. The increase was largely due to higher debt levels to fund capital investments, partially offset by lower long-term and short-term interest rates.

Income Taxes — Income taxes decreased $134 million for 2020. The decrease was primarily driven by an increase in wind PTCs and an increase in plant-related regulatory differences.

Xcel Energy Inc. and Other Results

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

	Contribution (Millions of Dollars)	
	2020	2019
Xcel Energy Inc. financing costs	$ (147)	$ (128)
MEC [a]	15	—
Eloigne [b]	1	1
Xcel Energy Inc. taxes and other results	(2)	12
Total Xcel Energy Inc. and other costs	$ (133)	$ (115)

	Contribution (Diluted Earnings (Loss) Per Share)	
	2020	2019
Xcel Energy Inc. financing costs	$ (0.28)	$ (0.21)
MEC [a]	0.03	—
Eloigne [b]	—	—
Xcel Energy Inc. taxes and other results	—	(0.01)
Total Xcel Energy Inc. and other costs	$ (0.25)	$ (0.22)

(a) MEC was sold in the third quarter of 2020.

(b) Amounts include gains or losses associated with sales of properties held by Eloigne.

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

2019 Comparison with 2018

A discussion of changes in Xcel Energy's results of operations, cash flows and liquidity and capital resources from the year ended Dec. 31, 2018 to Dec. 31, 2019 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 2019, which was filed with the SEC on Feb. 21, 2020. 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 WGI. 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 rates for utility services through filings with governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

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

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

NSP-Minnesota

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
MPUC	Retail rates, services, security issuances, property transfers, mergers, disposition of assets, affiliate transactions, and other aspects of electric and natural gas operations. Reviews and approves IRPs for meeting future energy needs. Certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV in Minnesota. Reviews and approves natural gas supply plans. Pipeline safety compliance.
NDPSC	Retail rates, services and other aspects of electric and natural gas operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota. Pipeline safety compliance.
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.
EIR	Recovers costs of environmental improvement projects in Minnesota.
RDF	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.
RER	Recovers cost of renewable generation in North Dakota.
SEP	Recovers costs related to various energy policies approved by the Minnesota legislature.
TCR	Recovers costs for investments in electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation and incremental property taxes in South Dakota.
FCA [(b)]	Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. MISO costs are generally recovered through either the FCA or base rates.
PGA	Provides for prospective monthly rate adjustments for costs of purchased natural gas, transportation and storage service. Includes a true-up process for difference between projected and actual costs.
GUIC Rider	Recovers costs for transmission and distribution pipeline integrity management programs, including: funding for pipeline assessments, deferred costs for sewer separation and pipeline integrity management programs in Minnesota.
Sales True-up	In February 2021, NSP-Minnesota filed the 2020 sales true-up compliance report, resulting in a total surcharge of $119 million. An MPUC ruling is anticipated in the second quarter of 2021. The 2021 sales true-up mechanism, extended under the 2020 stay-out petition, will operate similarly to the currently approved sales true-up and apply to all customer classes. Under the stay-out petition, 2021 NSP-Minnesota jurisdictional earnings will be capped at 9.06% ROE. Any excess earnings will be refunded to customers.

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

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

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2020 North Dakota Electric Rate Case	$22	November 2020	Pending
2020 TCR Electric Rider	82	November 2019	Pending
2020 GUIC Natural Gas Rider	21	November 2019	Pending
2021 GUIC Natural Gas Rider	27	October 2020	Pending
2020 RES Electric Rider	102	November 2019	Pending
2021 RES Electric Rider	189	November 2020	Pending

Additional Information:

2020 Minnesota Electric Rate Case and Stay-Out Alternative — In November 2020, NSP-Minnesota filed an electric rate case seeking a $597 million revenue increase over three years with the MPUC. The rate case is based on a requested ROE of 10.2% and a 52.5% equity ratio. NSP-Minnesota also filed a stay-out alternative in which it would withdraw its rate case filing.

In December 2020, the MPUC verbally approved the stay-out alternative petition, which includes the extension of the sales, capital and property tax true-up mechanisms and delays any increase to the Nuclear Decommissioning Trust annual accrual until Jan. 1, 2022.

Additionally, NSP-Minnesota agreed to not seek recovery of incremental COVID-19 related expenses, including bad debt expense, and committed to fund $18 million in a Residential Payment Plan Credit Program or other similar customer relief programs, as directed by the MPUC. NSP-Minnesota also agreed to an earnings test in which all earnings above an ROE of 9.06% in 2021 would be refunded to customers.

2020 North Dakota Electric Rate Case — In November 2020, NSP-Minnesota filed a request with the NDPSC for an overall increase in annual retail electric revenues of approximately $22 million, or an increase of 10.8%. The rate filing is based on a 2021 forecast test year, a requested ROE of 10.2%, an equity ratio of 52.50% and an electric rate base of approximately $677 million. Interim rates, subject to refund, of approximately $16 million were implemented on Jan. 5, 2021.

2020 TCR Electric Rider — In November 2019, NSP-Minnesota filed the TCR Rider based on an ROE of 9.06%. An MPUC decision is pending.

2020 GUIC Natural Gas Rider — In November 2019, NSP-Minnesota filed the GUIC Rider based on an ROE of 9.04%. An MPUC decision is pending.

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

2020 RES Electric Rider — In November 2019, NSP-Minnesota filed the RES Rider. The requested amount includes a true-up for the 2019 rider of $38 million and the 2020 requested amount of $64 million. The filing included an ROE of 9.06%. An MPUC decision is pending.

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

Minnesota Resource Plan — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034. The plan would result in an 80% carbon reduction by 2030 (from 2005) and puts NSP-Minnesota on a path to achieving its vision of being 100% carbon-free by 2050.

The updated preferred resource plan reflects the following:

- Retirement of all coal generation by 2030 with reduced operations at some units prior to retirement, including early retirement of the A.S. King coal plant (511 MW) in 2028 and the Sherco 3 coal plant (517 MW) in 2030.
- Extending the life of the Monticello nuclear plant from 2030 to 2040.
- Continuing to run the PI through current end of life (2033 and 2034).
- Construction of the Sherco combined cycle natural gas plant.
- The addition of 3,500 MW of solar.
- The addition of 2,250 MW of wind.
- 2,600 MW of firm peaking (combustion turbine, pumped hydro, battery storage, demand response, etc.).
- Achieving 780 GWh in energy efficiency savings annually through 2034.
- Adding 400 MW of incremental demand response by 2023, and a total of 1,500 MW of demand response by 2034.

Initial comments were submitted Feb. 11, 2021 and reply comments are due April 12, 2021. The MPUC is anticipated to make a final decision during 2021.

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

NSP-Minnesota's proposal included the following:

- Repower 651 MW of owned wind projects (capital investment of $750 million) as well as certain wind projects under PPAs.
- Acquire 120 MW repowered wind farm and buy-out of the remaining PPA from ALLETE for $210 million.
- Add solar facilities of 460 MW with an incremental investment of $550 million.
- Accelerate certain grid investment.
- Provide $150 million of incremental electric vehicle rebates.

In December 2020, the MPUC verbally approved the repowering of owned wind projects and 20 MW of wind projects under PPAs. These projects are estimated to save customers approximately $160 million over the next 25 years. The MPUC is expected to address the solar facilities, ALLETE PPA wind repowering acquisition and the electric vehicle proposal in the second half of 2021.

Purchased Power Arrangements and Transmission Service Provider

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

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

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

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

Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, MPUC and DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from Mankato to Winnebago, Minnesota. The project is estimated to cost approximately $120 million and projected to be in-service by the end of 2021. It was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute.

The complaint challenged the constitutionality of the statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. In June 2018, the Minnesota District Court granted Minnesota state agencies and NSP-Minnesota's motions to dismiss with prejudice. In February 2020, the Eighth Circuit Court of Appeals upheld the Minnesota District Court decision to dismiss. In June 2020, the Eighth Circuit denied LSP Transmission's petition for rehearing. In November 2020, LSP Transmission petitioned the U.S. Supreme Court to review its appeal. NSP-Minnesota filed a brief in opposition to this petition on Jan. 25, 2021.

Nuclear Power Operations

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

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

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

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

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

Wholesale and Commodity Marketing Operations

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

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

NSP-Wisconsin

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

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

Recovery Mechanisms

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

Pending and Recently Concluded Regulatory Proceedings

2021 Electric Fuel Cost Recovery — In December 2020, the PSCW approved the NSP-Wisconsin application to update its 2021 fuel cost and decrease retail electric rates for 2021 by approximately $12 million.

Request to Participate in Utility Money Pool — In October 2020, the PSCW approved NSP-Wisconsin's application to participate in the Money Pool.

NSP-Wisconsin Solar Proposal — In October 2020, NSP-Wisconsin filed for a 74 MW solar facility build-own-transfer in Wisconsin for approximately $100 million. A PSCW decision is expected in the third quarter of 2021.

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. 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 through the ECA. The ECA is revised quarterly.
PCCA	Recovers purchased capacity payments.
SCA	Recovers fuel costs to operate the steam system. The SCA rate is revised quarterly.
DSMCA	Recovers electric and gas DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
RESA	Recovers the incremental costs of compliance with the RES with a maximum of 1% of the customer's bill.
CEPA	Recovers the early retirement costs of Comanche units 1 and 2 to a maximum of 1% of the customer's bill.
WCA	Recovers costs for customers who choose renewable resources.
TCA	Recovers costs for transmission investment between rate cases.
CACJA	Recovers costs associated with the CACJA.
FCA	PSCo recovers fuel and purchased energy costs from wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay production costs through a forecasted formula rate subject to true-up.
GCA	Recovers costs of purchased natural gas and transportation and is revised quarterly to allow for changes in natural gas rates.
PSIA	Recovers costs for transmission and distribution pipeline integrity management programs.
Decoupling	Mechanism to true-up revenue to a baseline amount for residential (excluding lighting and demand) and metered non-demand small C&I classes. Represents approximately $51M for differences in sales to the baseline amount. Amounts refunded or surcharged to customers may be limited to a refund cap.

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2020 Natural Gas Rate Case	$77	February 2020	Received
2019 Electric Rate Case	108	May 2019	Received
2019 Natural Gas Rate Case Appeal	N/A	April 2019	Pending
Wildfire Protection Rider	325	July 2020	Pending
Transportation Electrification Plan Rider	110 - 138	May 2020	Received

Additional Information:

2020 Natural Gas Rate Case — In October 2020, the CPUC approved a settlement resulting in a net increase of $77 million. This increase reflects a $94 million increase in base rate revenue, partially offset by $17 million of costs previously recovered through the Pipeline Integrity rider. Rates will be implemented on April 1, 2021 (retroactive to November 2020).

2019 Electric Rate Case — In 2019, PSCo filed a request with the CPUC seeking a net rate increase of approximately $108 million. In February 2020, the CPUC issued an initial decision for a net rate increase of $35 million. In July 2020, the CPUC's final written decision on rehearing was received and resulted in an additional increase of approximately $12 million annually.

In December 2020, the CPUC denied PSCo's request of a $5 million surcharge for changes to the revenue increase from the effective date of rates, based on the CPUC's decision on rehearing. PSCo has appealed this decision with the District Court of Denver County.

2019 Phase I Electric Rate Case Appeal — In August 2020, PSCo filed an appeal with the Denver District Court seeking a review of CPUC decisions on gain on sales and losses of assets, oil and gas royalty revenues and Board of Director's equity compensation. PSCo plans to seek consolidation of this appeal with the appeal of the surcharge decision in this same proceeding.

2019 Natural Gas Rate Case Appeal — In April 2019, PSCo filed an appeal seeking judicial review of the CPUC's prior ruling regarding PSCo's natural gas rate case (filed in June 2017 and approved in December 2018). The appeal requested review of the following: denial of a return on the prepaid pension and retiree medical assets; the use of a capital structure not based on the actual historical test year; and use of an average rate base methodology rather than a year-end rate base methodology.

In March 2020, The District Court of Denver County ruled in favor of allowing the prepaid pension assets to be included in rate base; but upheld the CPUC's treatment of the retiree medical assets and capital structure methodology. In March 2021, PSCo expects to file a motion to implement the District Court's decision on treatment of the prepaid pension asset for the applicable period of Jan. 1, 2018 through Oct. 31, 2020.

Wildfire Protection Rider — In 2020, PSCo requested to establish a rider to recover incremental costs associated with system investments to reduce wildfire risk. The rider would be effective in June 2021 and continue through 2025. The Office of Consumer Counsel and CPUC Staff are supportive of the wildfire mitigation program as proposed, but oppose rider recovery and instead recommend deferral of certain costs with recovery in a future rate case. A CPUC decision is expected in the second quarter of 2021.

Wildfire Protection capital investment is projected to be approximately $325 million. Forecasted annual revenue requirements from 2021 through 2025:

(Millions of Dollars)	2021	2022	2023	2024	2025
Forecasted annual revenue requirement	$ 17	$ 24	$ 29	$ 32	$ 34

Transportation Electrification Plan — In January 2021, the CPUC approved PSCo's Transportation Electrification Plan, which authorizes rider recovery of new electric vehicle utility programs for the residential, commercial, multi-family and public charging sectors. The approval establishes utility-owned charging infrastructure and chargers and amortization of rebates for electric vehicles. The Transportation Electrification Plan approval authorizes approximately $110 million in spending with flexibility up to approximately $138 million over three years.

Advanced Grid Rider

In 2020, PSCo requested to establish a rider to recover incremental costs associated with the Advanced Grid Intelligence and Security initiative. The rider would be effective in May 2021 and continue through 2025. In October 2020, an ALJ issued The Recommended Decision granting the Office of Consumer Counsel motion to dismiss the Advanced Grid Rider. PSCo has chosen not to appeal the ALJ's Recommended Decision.

The PSCo portion of the Advanced Grid Intelligence and Security capital investment is projected to be approximately $850 million. Forecasted annual revenue requirements from 2021 through 2025 are as follows:

(Millions of Dollars)	2021	2022	2023	2024	2025
Forecasted annual revenue requirement	$ 53	$ 69	$ 83	$ 89	$ 99

PSCo KEPCO Filing

In September 2020, PSCo filed with the CPUC for approval to terminate a solar PPA with KEPCO Solar of Alamosa, Inc. and establish a regulatory asset to recover transaction costs of approximately $41 million. By terminating the PPA, customers would save approximately $38 million over an 11-year period. A CPUC decision is expected in the second quarter of 2021.

Natural Gas LDC and Emission Reductions

In October 2020, the CPUC opened a docket to investigate topics related to natural gas emissions in relation to statewide emission reduction goals. The first meeting was held in November 2020, in which subject matter experts discussed greenhouse emission reductions required from the natural gas industry in regard to the statewide goals.

Resource Plan

PSCo is expected to file its next Electric Resource Plan on March 31, 2021. The filing will propose the future of the remaining coal plants in Colorado and PSCo's plan to achieve it's 80% carbon emissions reduction target by 2030. A CPUC decision is expected in 2022.

PSCo — Comanche Unit 3

PSCo is part owner and operator of Comanche Unit 3, a 750 MW, coal-fueled electric generating unit. In January 2020, the unit experienced a turbine failure causing the unit to be taken offline for repairs, which were completed in June 2020. During start-up the unit experienced a loss of turbine oil, which damaged the plant. Comanche Unit 3 recommenced operations in January 2021. Replacement and repair of damaged systems in excess of a $2 million deductible are expected to be recovered through insurance policies. PSCo obtained replacement power costs of approximately $16 million during the outage. In October 2020, the CPUC initiated a non-adjudicatory review of Comanche Unit 3's performance. A report on performance is expected to be issued in March 2021. At this stage of the regulatory review, the resulting recommendations of the CPUC's staff cannot be determined.

Boulder Municipalization

In 2011, Boulder passed a ballot measure authorizing the formation of an electric municipal utility. Subsequently, there have been various legal proceedings in multiple venues.

In September 2020, the City Council voted to approve a settlement between PSCo and Boulder officials to end the city's municipalization effort. The settlement resulted in a 20-year franchise arrangement (with multiple opt-out conditions), an energy partnership and an undergrounding agreement. It also established the municipalization process if Boulder exercised an opt-out. In December 2020, PSCo filed the franchise agreement with the CPUC and is currently awaiting a decision.

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 is working towards joining the Western Energy Imbalance Market in 2022. This market was developed by the California ISO and allows PSCo access to a real-time energy market. The Western Energy Imbalance Market allows participants to buy and sell power close to the time electricity is consumed and gives system operators real-time visibility across neighboring grids. The result improves balancing supply and demand at a lower cost.

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

Wholesale and Commodity Marketing Operations

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

SPS

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

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

Recovery Mechanisms

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

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2019 New Mexico Electric Rate Case	$31	July 2019	Received
2019 Texas Electric Rate Case	88	August 2019	Received
2021 New Mexico Electric Rate Case	88	January 2021	Pending
2021 Texas Electric Rate Case	143	February 2021	Pending

Additional Information:

2019 New Mexico Electric Rate Case — In May 2020, the NMPRC approved a settlement between SPS and intervening parties, which reflects the following terms: a base rate increase of $31 million, an ROE of 9.45% and an equity ratio of 54.77%. New rates and tariffs were effective in May 2020.

2019 Texas Electric Rate Case — In August 2020, the PUCT approved a settlement between SPS and intervening parties, which reflects the following terms: a rate increase of $88 million; ROE of 9.45% and equity ratio of 54.62% for AFUDC purposes. In December 2020, SPS filed to surcharge the final under-recovered amount, estimated to be approximately $72 million, offset by the recognition of previously deferred costs.

2021 New Mexico Electric Rate Case — On Jan. 4, 2021, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $88 million. SPS' net rate increase to New Mexico customers is expected to be approximately $48 million, or 10%, as a result of offsetting fuel cost reductions and PTCs attributable to wind energy provided by the Sagamore wind project. PTCs are being credited to customers through the fuel clause.

The request is based on a historic test year ended Sept. 30, 2020, including expected capital additions through Feb. 28, 2021, a ROE of 10.35%, an equity ratio of 54.72% and retail rate base of approximately $1.9 billion (total company rate base of approximately $6.0 billion).

Additionally, the request includes the effect of approximately 400 MW of reduced peak load in 2021 from a wholesale transmission customer and changes to depreciation rates to reflect a reduction to the service lives of SPS' Tolk power plant (from 2037 to 2032) and the coal handling assets at the Harrington facility (to 2024).

The NMPRC suspended new rates for nine months beyond the 30-day notice period, consistent with historic practice.

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

- Staff and intervenor testimony — May 17, 2021.
- Rebuttal testimony — June 9, 2021.
- Deadline to file stipulation — June 23, 2021.
- Public hearing or hearing on stipulation — July 26 - Aug. 6, 2021.
- End of nine month suspension — Nov. 3, 2021.

A NMPRC decision and implementation of final rates is anticipated in the fourth quarter of 2021.

2021 Texas Rate Case — On Feb. 8, 2021, SPS filed an electric rate case with the PUCT and its 81 municipalities with original rate jurisdiction seeking an increase in base rates of approximately $143 million. SPS' net rate increase to Texas customers is expected to be approximately $74 million, or 9.2%, as a result of offsetting $69 million in fuel cost reductions and PTCs from the Sagamore wind project.

The request is primarily driven by additional capital investment in new and upgraded electric facilities and equipment since SPS' previous rate case in 2019, including the 522 MW Sagamore wind project.

The request is based on an ROE of 10.35%, an equity ratio of 54.60% (based on actual capital structure), a Texas retail rate base of approximately $3.3 billion and a historic test year based on the 12-month period ended Dec. 31, 2020 (with the final three months based on estimates). In March 2021, SPS will file to update estimates to actuals through Dec. 31, 2020.

Additionally, the request includes the effect of approximately 400 MW from a wholesale transmission customer and changes to depreciation rates to reflect a reduction to the service lives of SPS' Tolk power plant (from 2037 to 2032) and the coal handling assets of the Harrington facility (to 2024).

Summary of SPS' request:

Rate Request (Millions of Dollars)		
Sagamore wind project	$	67
Other capital investments		25
Cost of capital		20
Property taxes		8
Reduced sales, partially offset by changes in O&M		8
Allocator changes		4
Depreciation rate change		3
Other, net		8
Total rate request	$	143
Fuel cost reductions and PTCs — Sagamore wind project		(69)
Net rate increase	$	74

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

Texas State ROFR Litigation — In May 2019, the Governor signed a ROFR bill into law, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. In February 2020, the federal court complaint was dismissed by the district court. In March 2020, the district court ruling was appealed to the Fifth Circuit. A decision is pending.

New Mexico FPPCAC Continuation — In December 2020, the Hearing Examiner recommended the NMPRC approve SPS' request for the continued use of the FPPCAC and the reconciliation of its fuel costs for the reporting period (September 2015 through June 2019). Additionally, the Hearing Examiner recommended the NMPRC deny the proposed Annual Deferred Fuel Balance True-Up. The proposed true-up is designed to maintain the Deferred Fuel and Purchased Power balance within a bandwidth of plus or minus 5% of annual New Mexico fuel and purchased power costs. A decision is pending.

Resource Plan — SPS is required to file an IRP in New Mexico every three years and will file its next IRP in July 2021.

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 natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce and the PHMSA and PUCT for pipeline safety compliance.

Wholesale and Commodity Marketing Operations

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

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, 2020 and 2019, Xcel Energy had regulatory assets of $3.4 billion and regulatory liabilities of $5.6 billion and $5.5 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, 2020, in assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets.

See Note 4 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, 2020, Xcel Energy set the rate of return on assets used to measure pension costs at 6.49%, which represents a 38 basis point decrease from the rate set in 2019. The rate of return used to measure postretirement health care costs is 4.10% at Dec. 31, 2020, which represents a 40 basis point decrease from 2019.

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 a higher funded status and a greater percentage of growth assets being allocated to plans having a lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 2.71% and postretirement health care obligations at 2.65% at Dec. 31, 2020. This represents a 78 basis point and 82 basis point decrease, respectively, from 2019. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration.

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

If Xcel Energy were to use alternative assumptions, a 1% change would result in the following impact on 2020 pension costs:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (16)	$ 22
Discount rate [(a)]	$ (5)	$ 13

(a) These cost 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, 2020, the initial medical trend cost claim assumptions for Pre-65 was 5.5% and Post-65 was 5.0%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

Funding contributions in 2021 were $125 million and are expected to decline in the following years. Investment returns exceeded assumed levels in 2020 and 2019 and were below assumed levels in 2018.

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 2020).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $106 million in 2021 and $83 million in 2022, while the actual pension costs were $117 million in 2020 and $115 million in 2019. The expected decrease in 2021 and future year costs is primarily due to the reductions in loss amortizations.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2018 - 2021:

- $125 million in January 2021.
- $150 million in 2020.
- $154 million in 2019.
- $150 million in 2018.

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 $11 million, $15 million and $11 million during 2020, 2019 and 2018, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $10 million during 2021. 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 2018, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2018 pension settlement accounting expense.
- Regulatory Commissions in Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on GAAP. The Texas and Colorado electric retail jurisdictions and the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.
- In 2018, PSCo was required to create a regulatory liability to adjust postretirement health care costs to zero in order to match the amounts collected in rates in the Colorado Gas retail jurisdiction. In 2020, this requirement was extended to the Colorado Electric retail jurisdiction.

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

Nuclear Decommissioning

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

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The nuclear decommissioning obligation is funded by the external decommissioning trust fund. Difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $2.0 billion in 2020 and $2.1 billion in 2019.

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

The annual accrual (funding/recovery) set for 2019 and 2020 was based on the 2014 nuclear decommissioning filing, approved in 2015. Although the MPUC approved an increased accrual from the 2017 triennial filing in January 2019, the MPUC subsequently ordered Xcel Energy to maintain the accrual level (previously established via the 2014 filing) through 2020.

In December 2020, Xcel Energy submitted a 2020 triennial nuclear decommissioning filing to the MPUC. The filing resulted in an updated annual accrual of $33 million, or an increase of $19 million compared to the currently approved funding level. In December 2020, the MPUC verbally approved NSP-Minnesota to continue using the 2014 filing as the basis for 2021. The filing was also used to revise the estimated ARO liability as of Dec. 31, 2020 ($216 million decrease).

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

Timing — Decommissioning cost estimates are impacted by each facility's retirement date and timing of the actual decommissioning activities. Estimated retirement dates coincide with the expiration of each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method (required by the MPUC), which assumes prompt removal and dismantlement. Decommissioning activities are expected to begin at the end of the license date and be completed for both facilities by 2095.

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 applied escalation rates of 3.1% for PI and 3.2% for Monticello in calculating the nuclear decommissioning AROs, based on weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.

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

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

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

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

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the assumptions and uncertainties for each area. The information and assumptions of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2020.

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

Derivatives, Risk Management and Market Risk

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

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

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

Commodity Price Risk — We are exposed to commodity price risk in our electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Our risk management policy allows it 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 its risk management committee.

Fair value of net commodity trading contracts as of Dec. 31, 2020:

	Futures / Forwards Maturity				
(Millions of Dollars)	**Less Than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**Greater Than 5 Years**	**Total Fair Value**
NSP-Minnesota [a]	$ (2)	$ 1	$ 2	$ 2	$ 3
NSP-Minnesota [b]	(3)	3	(7)	(6)	(13)
PSCo [a]	—	1	—	—	1
PSCo [b]	(25)	(39)	(13)	—	(77)
	$ (30)	$ (34)	$ (18)	$ (4)	$ (86)

	Options Maturity				
(Millions of Dollars)	**Less Than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**Greater Than 5 Years**	**Total Fair Value**
NSP-Minnesota [b]	$ 1	$ —	$ —	$ 1	$ 2
PSCo [b]	13	16	1	—	30
	$ 14	$ 16	$ 1	$ 1	$ 32

(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)	**2020**	**2019**
Fair value of commodity trading net contracts outstanding at Jan. 1	$ (59)	$ 17
Contracts realized or settled during the period	(9)	(22)
Commodity trading contract additions and changes during the period	14	(54)
Fair value of commodity trading net contracts outstanding at Dec. 31	$ (54)	$ (59)

At Dec. 31, 2020, a 10% increase in market prices for commodity trading contracts through the forward curve would increase pretax income from continuing operations by approximately $13 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $13 million. At Dec. 31, 2019, a 10% increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $10 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $10 million. Market price movements can exceed 10% under abnormal circumstances.

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

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

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2020	$ 1	$ 3	$ 1	$ 2	$ 1
2019	< 1	3	1	1	< 1

Nuclear Fuel Supply — NSP-Minnesota has contracted for approximately 11% of its 2021 enriched nuclear material requirements from sources that could be impacted by sanctions against entities doing business with Iran. Those sanctions may impact the supply of enriched nuclear material supplied from Russia. Long-term, through 2030, NSP-Minnesota is scheduled to take delivery of approximately 28% of its average enriched nuclear material requirements from these sources. NSP-Minnesota is able to manage nuclear fuel supply with alternate potential sources. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

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

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $6 million in 2020 and 2019, respectively.

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

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

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

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

At Dec. 31, 2020, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $11 million, while a decrease in prices of 10% would have resulted in an immaterial increase in credit exposure. At Dec. 31, 2019, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $19 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $14 million.

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

Fair Value Measurements

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

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

Commodity Derivatives — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. The impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2020.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2020.

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 — 2019	$ 3,263
Components of change — 2020 vs. 2019	
Higher net income	101
Non-cash transactions [(a)]	(49)
Changes in working capital [(b)]	(222)
Changes in net regulatory and other assets and liabilities	(245)
Cash provided by operating activities — 2020	$ 2,848

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

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

Net cash provided by operating activities decreased by $415 million for 2020 as compared to 2019. Decrease was primarily due to changes in accounts receivable related to increased residential sales, timing of regulatory asset recovery and inventory wind turbine purchases, which were partially offset by an increase in net income.

Investing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31
Cash used in investing activities — 2019	$ (4,343)
Components of change — 2020 vs. 2019	
Increased capital expenditures	(1,144)
Sale of MEC	684
Other investing activities	63
Cash used in investing activities — 2020	$ (4,740)

Net cash used in investing activities increased by $397 million for 2020 as compared to 2019. Increase was primarily attributable to additional capital expenditures, primarily for wind projects, including Sagamore, Cheyenne Ridge, Blazing Star 1 and Crowned Ridge 2.

Financing Cash Flows

(Millions of Dollars)	Twelve Months Ended Dec. 31
Cash provided by financing activities — 2019	$ 1,181
Components of change — 2020 vs. 2019	
Higher debt issuances	452
Higher repayments of long-term debt	(52)
Higher proceeds from issuance of common stock	269
Higher dividends paid to shareholders	(65)
Other financing activities	(12)
Cash provided by financing activities — 2020	$ 1,773

Net cash provided by financing activities increased by $592 million for 2020 as compared to 2019. Increase was primarily attributable to higher proceeds from issuances of long-term debt and common stock (due to forward equity agreements settling in November 2020 and August 2019), partially offset by higher repayments of long-term debt and dividends paid.

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

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Contractual Obligations and Other Commitments — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. Contractual obligations and other commercial commitments as of Dec. 31, 2020:

	Payments Due by Period				
(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	$ 34,312	$ 1,183	$ 3,249	$ 3,107	$ 26,773
Finance lease obligations	257	14	24	22	197
Operating leases obligations [(a)]	1,859	273	497	434	655
Unconditional purchase obligations [(b)]	5,005	1,366	1,585	911	1,143
Other long-term obligations, including current portion	637	74	63	60	440
Other short-term obligations	420	420	—	—	—
Short-term debt	584	584	—	—	—
Total contractual cash obligations	$ 43,074	$ 3,914	$ 5,418	$ 4,534	$ 29,208

(a) Included in operating lease obligations are $247 million, $446 million, $398 million and $561 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.

Capital Expenditures — The capital forecasts for Xcel Energy for 2021 through 2025 are detailed in the following tables. The base capital forecast has been updated to reflect the MPUC's approval of the $750 million wind repowering proposal. In addition, the base capital forecast reflects a change in the timing of completion of a wind project from 2020 to 2021.

	Actual	Base Capital Forecast (Millions of Dollars)					
By Regulated Utility	2020	2021	2022	2023	2024	2025	2021 - 2025 Total
PSCo	$ 1,600	$ 1,700	$ 1,835	$ 1,750	$ 1,695	$ 1,655	$ 8,635
NSP-Minnesota	1,955	1,930	1,785	1,785	1,915	1,890	9,305
SPS	1,180	505	710	770	735	675	3,395
NSP-Wisconsin	235	360	430	395	515	470	2,170
Other [(a)]	(135)	(20)	(15)	10	10	10	(5)
Total base capital expenditures	$ 4,835	$ 4,475	$ 4,745	$ 4,710	$ 4,870	$ 4,700	$ 23,500

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

	Actual	Base Capital Forecast (Millions of Dollars)					
By Function	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2021 - 2025 Total**
Electric distribution	$ 980	$ 1,205	$ 1,440	$ 1,550	$ 1,505	$ 1,475	$ 7,175
Electric transmission	695	870	1,285	1,285	1,270	1,290	6,000
Electric generation	445	630	575	560	750	975	3,490
Natural gas	580	615	615	665	670	625	3,190
Other	345	545	575	485	405	335	2,345
Renewables	1,790	610	255	165	270	—	1,300
Total base capital expenditures	$ 4,835	$ 4,475	$ 4,745	$ 4,710	$ 4,870	$ 4,700	$ 23,500

	Incremental Capital Forecast (Millions of Dollars) [(a)]					
NSP-Minnesota Proposal	**2021**	**2022**	**2023**	**2024**	**2025**	**2021 - 2025 Total**
Sherco solar	$ 30	$ 200	$ 320	$ —	$ —	$ 550
Wind PPA buyout	25	185	—	—	—	210
Total incremental capital	$ 55	$ 385	$ 320	$ —	$ —	$ 760

(a) Reflects potential capital investment under the Minnesota Relief and Recovery Plan, which will require MPUC approval. The incremental capital investment is not included in the base capital forecast.

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, reserve requirements, availability of purchased power, alternative plans for meeting long-term energy needs, environmental initiatives and regulation, and mergers, acquisition and divestiture opportunities.

Financing Capital Expenditures through 2025 — 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. Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions, changes in tax policies, and other factors.

Current estimated financing plans for 2021 - 2025:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from operations [(a)]	$ 15,000
New debt [(b)]	7,490
Equity through the DRIP and benefit program	410
Other equity	600
Base capital expenditures 2021 - 2025	$ 23,500
Maturing Debt	$ 3,820

(a) Net of dividends and pension funding.

(b) Reflects a combination of short and long-term debt; net of refinancing.

The incremental renewable capital expenditures would be financed with approximately 50% debt and 50% equity, if approved by the MPUC.

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 2021, Xcel Energy announced a quarterly dividend of $0.4575 per share, which represents an increase of 6.4%.

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, 2020	Dec. 31, 2019
Fair value of pension assets	$ 3,599	$ 3,184
Projected pension obligation [(a)]	3,964	3,701
Funded status	$ (365)	$ (517)

(a) Excludes non-qualified plan of $43 million and $39 million at Dec. 31, 2020 and 2019, respectively.

Pension Assumptions	2020	2019
Discount rate	2.71 %	3.49 %
Expected long-term rate of return	6.49	6.87

Capital Sources

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

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

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

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

In addition, in December 2020, Xcel Energy Inc. repaid its $500 million Term Loan Agreement. In September 2020, Xcel Energy Inc. repaid its $700 million Term Loan Agreement.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2020
Borrowing limit	$ 3,100
Amount outstanding at period end	584
Average amount outstanding	415
Maximum amount outstanding	613
Weighted average interest rate, computed on a daily basis	0.60 %
Weighted average interest rate at end of period	0.23

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2020	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Borrowing limit	$ 3,100	$ 3,600	$ 3,250
Amount outstanding at period end	584	595	1,038
Average amount outstanding	1,126	1,115	788
Maximum amount outstanding	2,080	1,780	1,349
Weighted average interest rate, computed on a daily basis	1.45 %	2.72 %	2.34 %
Weighted average interest rate at end of period	0.23	2.34	2.97

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

As of Feb. 16, 2021, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,250	$ 696	$ 554	$ 2	$ 556
PSCo	700	142	558	2	560
NSP-Minnesota	500	129	371	2	373
SPS	500	341	159	1	160
NSP-Wisconsin	150	—	150	5	155
Total	$ 3,100	$ 1,308	$ 1,792	$ 12	$ 1,804

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

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2020 and 2019, Xcel Energy had approximately 537 million shares and 525 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 2021 financing plans reflect the following:

- Xcel Energy Inc. — approximately $1.2 billion in debt financing.
- PSCo — approximately $750 million of first mortgage bonds.
- SPS — approximately $250 million of first mortgage bonds.
- NSP-Minnesota — approximately $850 million of first mortgage bonds.
- NSP-Wisconsin — approximately $125 million of first mortgage bonds.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward equity agreements in connection with a completed $459 million public offering of 9.4 million shares of Xcel Energy common stock. In August 2019, Xcel Energy settled the forward equity agreements by delivering 9.4 million shares of common equity for cash proceeds of $453 million.

In November 2019, Xcel Energy Inc. entered into forward equity agreements for a $743 million public offering of 11.8 million shares of Xcel Energy common stock. In November 2020, Xcel Energy settled the forward equity agreements by delivering 11.8 million shares of common equity for cash proceeds of $721 million.

Equity through DRIP and Benefits Program — Xcel Energy also plans to issue approximately $75 to $90 million of equity annually through the DRIP and benefit programs during the five-year forecast time period.

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

Natural Gas Fuel and Electricity Purchases

In February 2021, the United States experienced winter storm Uri and extreme cold temperatures in the central United States. This severe weather event increased the demand for natural gas used in our electric and natural gas businesses. Certain operational assets were impacted by extreme cold temperatures and safety protocols and the cold further impacted the availability of renewable generation across the region (which typically acts as a hedge against commodity prices) contributing to extremely high market prices for natural gas and electricity. As a result, electric and natural gas fuel costs increased approximately $1.2 billion (PSCo - $650 million, NSP-Minnesota - $300 million, SPS - $200 million and NSP-Wisconsin - $45 million). These amounts are preliminary estimates through Feb. 16, 2021 and are subject to final settlement.

Xcel Energy has fuel recovery mechanisms in all of its states to recover the increased cost of natural gas and electricity. However, given the impact of these higher costs to our customers during a pandemic, we expect our regulators to undertake a heightened review and we intend to work with our commissions to recover these costs over time to help mitigate the impacts on customer bills. Xcel Energy is taking action to increase planned debt issuances to ensure adequate liquidity for the timing difference between fuel payments and revenue collection from customers and to address any potential need to post collateral.

Earnings Guidance

2021 GAAP and ongoing earnings guidance is a range of $2.90 to $3.00 per share. [(a)]

Key assumptions as compared with 2020 levels unless noted:

- Constructive outcomes in all rate case and regulatory proceedings.
- Modest impacts from COVID-19.
- Normal weather patterns for the remainder of the year.
- Weather-normalized retail electric sales are projected to increase ~1%.
- Weather-normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase $105 million to $115 million (net of PTCs). The change reflects the deferral of advanced grid costs, which were denied rider recovery. PTCs are credited to customers, through capital riders, fuel clause or base rates and results in a reduction to electric margin.
- O&M expenses are projected to be relatively flat.
- Depreciation expense is projected to increase approximately $195 million to $205 million.
- Property taxes are projected to increase approximately $45 million to $55 million.
- Interest expense (net of AFUDC - debt) is projected to increase $0 million to $10 million.
- AFUDC - equity is projected to decline approximately $45 million to $55 million.
- ETR is projected to be ~(9%). The ETR reflects benefits of PTCs which are credited to customers through electric margin and will not have a material impact on net income.

(a) Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations. Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing EPS to corresponding GAAP EPS.

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.

COVID-19

Although the COVID-19 pandemic has led to numerous challenges, Xcel Energy believes its risk management program, including business continuity and disaster recovery planning, will continue to allow us to proactively manage and successfully navigate challenges, risks and uncertainties.

There is continued uncertainty regarding COVID-19, the duration and magnitude of business restrictions, re-shut downs and the level and pace of economic recovery. Also, while we may implement contingency plans, there are no guarantees these plans will be sufficient to offset the impact of the pandemic, which could have a material impact on our results of operations, financial condition or cash flow.

An overview of certain risk considerations or areas which have or could significantly impact us, is as follows.

Sales — Xcel Energy has experienced and may continue to experience higher residential sales and lower C&I sales as a result of COVID-19. Xcel Energy has decoupling and sales true-up mechanisms in Minnesota (all electric classes) and Colorado (residential and non-demand small C&I electric classes), which mitigate the impact of changes to sales levels as compared to a baseline.

Bad Debt — Bad debt expense could significantly increase due to pandemic related economic impacts, customer hardship, federal or state legislation and regulatory orders. However, several of our commissions have approved the deferral of incremental COVID-19 related expense, including bad debt expense.

Xcel Energy has received orders in Colorado, Wisconsin, Texas, New Mexico, North Dakota, South Dakota and Michigan, allowing regulatory deferral of incremental COVID-19 costs as a regulatory asset subject to future determination of amount and timing of recovery. As part of NSP-Minnesota's stay-out alternative, NSP-Minnesota agreed to not seek recovery of incremental COVID-19 related costs.

The majority of wholesale customers are subject to formula transmission and production rates, which true-up rates to actual costs to serve.

Supply Chain and Capital Expenditures — 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. During 2020, Xcel Energy did not experience supply chain, contractor or employee disruptions with the exception of delays in certain wind projects.

Liquidity — Xcel Energy took steps to enhance its liquidity in 2020 and believes it has more than adequate liquidity. Xcel Energy will take steps to enhance liquidity in 2021 if needed.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See 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, 2020. 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, 2020, 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 audit report on Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE	/s/ BRIAN J. VAN ABEL
Ben Fowke	Brian J. Van Abel
Chairman, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer
Feb. 17, 2021	Feb. 17, 2021

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, 2020 and 2019, 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, 2020, 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, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 judgements 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 memorandums, filings made by intervenors, 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 17, 2021

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		
	2020	2019	2018
Operating revenues			
Electric	$ 9,802	$ 9,575	$ 9,719
Natural gas	1,636	1,868	1,739
Other	88	86	79
Total operating revenues	11,526	11,529	11,537
Operating expenses			
Electric fuel and purchased power	3,512	3,510	3,854
Cost of natural gas sold and transported	689	918	843
Cost of sales — other	37	40	35
Operating and maintenance expenses	2,324	2,338	2,352
Conservation and demand side management expenses	288	285	290
Depreciation and amortization	1,948	1,765	1,642
Taxes (other than income taxes)	612	569	556
Total operating expenses	9,410	9,425	9,572
Operating income	2,116	2,104	1,965
Other (expense) income, net	(6)	16	(14)
Equity earnings of unconsolidated subsidiaries	40	39	35
Allowance for funds used during construction — equity	115	77	108
Interest charges and financing costs			
Interest charges — includes other financing costs of $28, $26 and $25, respectively	840	773	700
Allowance for funds used during construction — debt	(42)	(37)	(48)
Total interest charges and financing costs	798	736	652
Income before income taxes	1,467	1,500	1,442
Income tax (benefit) expense	(6)	128	181
Net income	$ 1,473	$ 1,372	$ 1,261
Weighted average common shares outstanding:			
Basic	527	519	511
Diluted	528	520	511
Earnings per average common share:			
Basic	$ 2.79	$ 2.64	$ 2.47
Diluted	2.79	2.64	2.47

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2020	2019	2018
Net income	$ 1,473	$ 1,372	$ 1,261
Other comprehensive (loss) income			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of $(2), $— and $(2), respectively	(5)	—	(6)
Reclassification of losses to net income, net of tax of $3, $1 and $3, respectively	10	3	9
Derivative instruments:			
Net fair value decrease, net of tax of $(3), $(8) and $(2), respectively	(10)	(23)	(5)
Reclassification of losses to net income, net of tax of $2, $1 and $1, respectively	5	3	3
Total other comprehensive (loss) income	—	(17)	1
Total comprehensive income	$ 1,473	$ 1,355	$ 1,262

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2020	2019	2018
Operating activities			
Net income	$ 1,473	$ 1,372	$ 1,261
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,959	1,785	1,659
Nuclear fuel amortization	123	119	122
Deferred income taxes	(8)	143	218
Allowance for equity funds used during construction	(115)	(77)	(108)
Equity earnings of unconsolidated subsidiaries	(40)	(39)	(35)
Dividends from unconsolidated subsidiaries	42	40	37
Provision for bad debts	60	42	42
Share-based compensation expense	73	58	45
Net realized and unrealized hedging and derivative transactions	(27)	45	22
Changes in operating assets and liabilities:			
Accounts receivable	(154)	(20)	(105)
Accrued unbilled revenues	(3)	42	9
Inventories	(80)	(84)	(65)
Other current assets	(45)	25	18
Accounts payable	(33)	(12)	90
Net regulatory assets and liabilities	(144)	(66)	223
Other current liabilities	29	(15)	(61)
Pension and other employee benefit obligations	(125)	(135)	(179)
Other, net	(137)	40	(71)
Net cash provided by operating activities	2,848	3,263	3,122
Investing activities			
Capital/construction expenditures	(5,369)	(4,225)	(3,957)
Sale of MEC	684	—	—
Purchase of investment securities	(1,398)	(995)	(853)
Proceeds from the sale of investment securities	1,378	975	833
Other, net	(35)	(98)	(9)
Net cash used in investing activities	(4,740)	(4,343)	(3,986)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(11)	(443)	225
Proceeds from issuances of long-term debt	2,940	2,920	1,675
Repayments of long-term debt, including reacquisition premiums	(1,001)	(949)	(452)
Proceeds from issuance of common stock	727	458	230
Dividends paid	(856)	(791)	(730)
Other, net	(26)	(14)	(20)
Net cash provided by financing activities	1,773	1,181	928
Net change in cash and cash equivalents	(119)	101	64
Cash and cash equivalents at beginning of period	248	147	83
Cash and cash equivalents at end of period	$ 129	$ 248	$ 147
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (758)	$ (698)	$ (633)
Cash received for income taxes, net	12	53	27
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 400	$ 421	$ 388
Inventory transfers to property, plant and equipment	275	88	129
Operating lease right-of-use assets	369	1,843	—
Allowance for equity funds used during construction	115	77	108
Issuance of common stock for equity awards	67	63	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 2020	Dec. 31 2019
Assets		
Current assets		
Cash and cash equivalents	$ 129	$ 248
Accounts receivable, net	916	837
Accrued unbilled revenues	714	713
Inventories	535	544
Regulatory assets	640	488
Derivative instruments	49	55
Prepaid taxes	42	43
Prepayments and other	250	185
Total current assets	3,275	3,113
Property, plant and equipment, net	42,950	39,483
Other assets		
Nuclear decommissioning fund and other investments	3,096	2,731
Regulatory assets	2,737	2,935
Derivative instruments	30	22
Operating lease right-of-use assets	1,490	1,672
Other	379	492
Total other assets	7,732	7,852
Total assets	$ 53,957	$ 50,448
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 421	$ 702
Short-term debt	584	595
Accounts payable	1,237	1,294
Regulatory liabilities	311	407
Taxes accrued	578	466
Accrued interest	203	192
Dividends payable	231	212
Derivative instruments	53	38
Operating lease liabilities	214	194
Other	407	468
Total current liabilities	4,239	4,568
Deferred credits and other liabilities		
Deferred income taxes	4,746	4,509
Deferred investment tax credits	45	49
Regulatory liabilities	5,302	5,077
Asset retirement obligations	2,884	2,701
Derivative instruments	131	175
Customer advances	197	203
Pension and employee benefit obligations	666	785
Operating lease liabilities	1,344	1,549
Other	183	186
Total deferred credits and other liabilities	15,498	15,234
Commitments and contingencies		
Capitalization		
Long-term debt	19,645	17,407
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 537,438,394 and 524,539,000 shares outstanding at Dec. 31, 2020 and Dec. 31, 2019, respectively	1,344	1,311
Additional paid in capital	7,404	6,656
Retained earnings	5,968	5,413
Accumulated other comprehensive loss	(141)	(141)
Total common stockholders' equity	14,575	13,239
Total liabilities and equity	$ 53,957	$ 50,448

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(amounts in millions, shares in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2017	507,763	$ 1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				1,261		1,261
Other comprehensive income					1	1
Dividends declared on common stock ($1.52 per share)				(780)		(780)
Issuances of common stock	6,296	16	254			270
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			17	(1)		16
Balance at Dec. 31, 2018	514,037	$ 1,285	$ 6,168	$ 4,893	$ (124)	$ 12,222
Net Income				1,372		1,372
Other comprehensive loss					(17)	(17)
Dividends declared on common stock ($1.62 per share)				(846)		(846)
Issuances of common stock	10,508	26	468			494
Repurchase of common stock	(6)	—	—			—
Share-based compensation			20	(6)		14
Balance at Dec. 31, 2019	524,539	$ 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	12,954	33	731			764
Repurchase of common stock	(55)	—	(4)			(4)
Share-based compensation			21	(7)		14
Adoption of ASC Topic 326				(2)		(2)
Balance at Dec. 31, 2020	537,438	$ 1,344	$ 7,404	$ 5,968	$ (141)	$ 14,575

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

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

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

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

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. All intercompany transactions and balances are eliminated, unless a different treatment is appropriate for rate regulated transactions.

Xcel Energy uses the equity method of accounting for its investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries.

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

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

Xcel Energy has evaluated events occurring after Dec. 31, 2020 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 on items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

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

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

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

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

See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. Xcel Energy uses rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

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

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

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

Xcel Energy reports interest and penalties related to income taxes within other (expense) income or interest charges in the consolidated statements of income, based on the underlying nature of the transaction.

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

See Note 7 for further information.

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

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

Xcel Energy records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs of Xcel Energy's utility subsidiaries are recovered in rates as authorized by the appropriate regulatory entities. The amount of removal costs are based on current factors used in existing depreciation rates. Accumulated removal costs are reflected in the consolidated balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.4% for 2020, 3.3% for 2019 and 3.1% for 2018.

See Note 3 for further information.

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

See Note 12 for further information.

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

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

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

See Notes 10 and 12 for further information.

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

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

See Note 11 for further information.

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

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

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

See Note 12 for further information.

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

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

See Note 6 for further information.

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

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

As of Dec. 31, 2020 and 2019, the allowance for bad debts was $79 million and $55 million, respectively.

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

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
Inventories		
Materials and supplies	$ 275	$ 270
Fuel	176	191
Natural gas	84	83
Total inventories	$ 535	$ 544

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

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

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

See Notes 10 and 11 for further information.

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

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

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

See Note 10 for further information.

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

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

See Note 10 for further information.

Other Utility Items

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

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

See Note 6 for further information.

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

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

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

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. In certain jurisdictions, Xcel Energy reduces recoverable fuel costs for the cost of RECs and records that cost as a regulatory asset when the amount is recoverable in future rates.

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

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

2. Accounting Pronouncements

Recently Adopted

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

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

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
Property, plant and equipment, net		
Electric plant	$ 47,104	$ 44,355
Natural gas plant	7,135	6,560
Common and other property	2,503	2,341
Plant to be retired [(a)]	677	259
CWIP	1,877	2,329
Total property, plant and equipment	59,296	55,844
Less accumulated depreciation	(16,657)	(16,735)
Nuclear fuel	2,970	2,909
Less accumulated amortization	(2,659)	(2,535)
Property, plant and equipment, net	$ 42,950	$ 39,483

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

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2020:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Minnesota				
Electric generation:				
Sherco Unit 3	$ 601	$ 435	$ 2	59 %
Sherco common facilities	149	108	5	80
Sherco substation	5	3	—	59
Electric transmission:				
Grand Meadow	11	3	—	50
CapX2020	954	108	33	51
Total NSP-Minnesota	$ 1,720	$ 657	$ 40	

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Wisconsin				
Electric transmission:				
La Crosse, WI to Madison, WI	$ 188	$ 12	$ —	37 %
CapX2020	169	23	—	80
Total NSP-Wisconsin	$ 357	$ 35	$ —	

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
PSCo				
Electric generation:				
Hayden Unit 1	$ 153	$ 92	$ —	76 %
Hayden Unit 2	150	73	—	37
Hayden common facilities	42	25	—	53
Craig Units 1 and 2	81	44	—	10
Craig common facilities	39	24	—	7
Comanche Unit 3	899	137	16	67
Comanche common facilities	25	2	—	82
Electric transmission:				
Transmission and other facilities	176	59	2	Various
Gas transmission:				
Rifle, CO to Avon, CO	22	8	—	60
Gas transmission compressor	8	1	—	50
Total PSCo	$ 1,595	$ 465	$ 18	

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, 2020		Dec. 31, 2019	
Regulatory Assets			**Current**	**Noncurrent**	**Current**	**Noncurrent**
Pension and retiree medical obligations	11	Various	$ 82	$ 1,268	$ 85	$ 1,328
Recoverable deferred taxes on AFUDC		Plant lives	—	283	—	271
Excess deferred taxes — TCJA	7	Various	16	229	39	239
Depreciation differences		One to 11 years	16	154	15	140
Net AROs [(a)]	1, 12	Various	—	139	—	269
Environmental remediation costs	1, 12	Various	16	113	36	131
Benson biomass PPA termination and asset purchase		Nine years	10	65	9	73
Purchased power contract costs		Term of related contract	7	54	5	61
PI extended power uprate		14 years	3	49	3	53
Contract valuation adjustments [(b)]	1, 10	Term of related contract	23	48	20	62
Losses on reacquired debt		Term of related debt	4	38	4	41
Laurentian biomass PPA termination		Three years	18	36	19	54
Conservation programs [(c)]	1	One to two years	26	36	27	26
State commission adjustments		Plant lives	1	32	1	31
Sales true-up and revenue decoupling		One to two years	101	28	54	16
Property tax		Various	16	21	2	30
Deferred purchased natural gas and electric energy costs		One to two years	14	18	6	6
Texas revenue surcharge		One to two years	54	17	2	—
Renewable resources and environmental initiatives		One to two years	129	12	72	10
Nuclear refueling outage costs	1	One to two years	28	10	43	17
Gas pipeline inspection and remediation costs		One to two years	26	9	26	8
Other		Various	50	78	20	69
Total regulatory assets			$ 640	$ 2,737	$ 488	$ 2,935

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

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2020		Dec. 31, 2019	
Regulatory Liabilities			**Current**	**Noncurrent**	**Current**	**Noncurrent**
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 20	$ 3,368	$ 75	$ 3,523
Plant removal costs	1, 12	Various	—	1,520	—	1,217
Effects of regulation on employee benefit costs [(b)]		Various	—	221	—	196
Renewable resources and environmental initiatives		Various	5	59	—	45
ITC deferrals	1	Various	—	51	—	38
Revenue decoupling		One to two years	10	41	—	—
Deferred electric, natural gas and steam production costs		Less than one year	84	—	138	—
Conservation programs [(c)]	1	Less than one year	49	—	37	—
DOE settlement		Less than one year	23	—	37	—
Contract valuation adjustments [(d)]	1, 10	Less than one year	19	—	19	—
Other		Various	101	42	101	58
Total regulatory liabilities [(e)]			$ 311	$ 5,302	$ 407	$ 5,077

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.
(b) Includes regulatory amortization and certain 2018 TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset.
(c) Includes 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.
(e) Revenue subject to refund of $17 million and $28 million for 2020 and 2019, respectively, is included in other current liabilities.

At Dec. 31, 2020 and 2019, Xcel Energy's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, regulatory assets included $812 million and $544 million at Dec. 31, 2020 and 2019, respectively, of past expenditures not earning a return. Amounts are related to funded pension obligations, sales true-up and revenue decoupling, purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

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

Commercial paper and term loan borrowings outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2020	Year Ended Dec. 31 2020	2019	2018
Borrowing limit	$ 3,100	$3,100	$3,600	$3,250
Amount outstanding at period end	584	584	595	1,038
Average amount outstanding	415	1,126	1,115	788
Maximum amount outstanding	613	2,080	1,780	1,349
Weighted average interest rate, computed on a daily basis	0.60 %	1.45 %	2.72 %	2.34 %
Weighted average interest rate at period end	0.23	0.23	2.34	2.97

Term Loan Agreements — In December 2020, Xcel Energy Inc. repaid its $500 million Term Loan Agreement that was entered into December 2018. In September 2020, Xcel Energy Inc. repaid its $700 million Term Loan Agreement that was entered into March 2020. As of Dec. 31, 2020, Xcel Energy Inc. has no open loan agreement.

Bilateral Credit Agreement — In March 2019, NSP-Minnesota entered into a one-year uncommitted bilateral credit agreement. The agreement is limited in use to support letters of credit. In March 2020, NSP-Minnesota renewed its bilateral credit agreement for an additional one-year term.

As of Dec. 31, 2020, outstanding letters of credit under the Bilateral Credit Agreement were as follows:

(Millions of Dollars)	Limit	Amount Outstanding	Available
NSP-Minnesota	$ 75	$ 49	$ 26

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, 2020 and 2019, there were $20 million of letters of credit outstanding under the credit facilities. 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 in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Terms of Credit Agreements — In June 2019, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements is $3.1 billion, with a swingline subfacility for Xcel Energy up to $75 million. The amended credit agreements mature in June 2024.

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio[a] 2020	2019	Amount Facility May Be Increased (millions)	Additional Periods for Which a One-Year Extension May Be Requested [b]
Xcel Energy Inc. [c]	59 %	58 %	$ 200	2
NSP-Wisconsin	46	48	N/A	1
NSP-Minnesota	47	48	100	2
SPS	48	46	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, 2020, 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, 2020:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available
Xcel Energy Inc.	$ 1,250	$ —	$ 1,250
PSCo	700	144	556
NSP-Minnesota	500	189	311
SPS	500	252	248
NSP-Wisconsin	150	19	131
Total	$ 3,100	$ 604	$ 2,496

(a) These credit facilities mature in June 2024.

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

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its utility subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2020 and 2019.

Long-Term Borrowings and Other Financing Instruments

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

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

Xcel Energy Inc.

Financing Instrument	Interest Rate	Maturity Date	2020	2019
Unsecured senior notes	2.40 %	March 15, 2021	$ 400	$ 400
Unsecured senior notes [c]	2.60	March 15, 2022	—	300
Unsecured senior notes [a]	0.50	Oct. 15, 2023	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 [b]	4.00	June 15, 2028	130	130
Unsecured senior notes	4.00	June 15, 2028	500	500
Unsecured senior notes [b]	2.60	Dec. 1, 2029	500	500
Unsecured senior notes [a]	3.40	June 1, 2030	600	—
Unsecured senior notes	6.50	July 1, 2036	300	300
Unsecured senior notes	4.80	Sept. 15, 2041	250	250
Unsecured senior notes [b]	3.50	Dec. 1, 2049	500	500
Unamortized discount			(7)	(5)
Unamortized debt issuance cost			(32)	(28)
Current maturities			(400)	—
Total long-term debt			$ 4,341	$ 3,947

(a) 2020 financing.
(b) 2019 financing.
(c) Note was redeemed on Dec. 1, 2020.

NSP-Minnesota

Financing Instrument	Interest Rate	Maturity Date	2020	2019
First mortgage bonds	2.20 %	Aug. 15, 2020	$ —	$ 300
First mortgage bonds	2.15	Aug. 15, 2022	300	300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.13	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
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	4.13	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	Sept. 15, 2047	600	600
First mortgage bonds [b]	2.90	March 1, 2050	600	600
First mortgage bonds [a]	2.60	June 1, 2051	700	—
Unamortized discount			(42)	(31)
Unamortized debt issuance cost			(54)	(48)
Current maturities			—	(300)
Total long-term debt			$ 5,904	$ 5,221

(a) 2020 financing.
(b) 2019 financing.

NSP-Wisconsin

Financing Instrument	Interest Rate	Maturity Date	2020	2019
City of La Crosse resource recovery bond	6.00 %	Nov 1, 2021	$ 19	$ 19
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	6.38	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 [a]	3.05	May 1, 2051	100	—
Unamortized discount			(4)	(3)
Unamortized debt issuance cost			(9)	(8)
Current maturities			(19)	—
Total long-term debt			$ 887	$ 808

(a) 2020 financing.

PSCo

Financing Instrument	Interest Rate	Maturity Date	2020	2019
First mortgage bonds	3.20 %	Nov. 15, 2020	$ —	$ 400
First mortgage bonds	2.25	Sept. 15, 2022	300	300
First mortgage bonds	2.50	March 15, 2023	250	250
First mortgage bonds	2.90	May 15, 2025	250	250
First mortgage bonds	3.70	June 15, 2028	350	350
First mortgage bonds [a]	1.90	Jan. 15, 2031	375	—
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 [b]	4.05	Sept. 15, 2049	400	400
First mortgage bonds [b]	3.20	March 1, 2050	550	550
First mortgage bonds [a]	2.70	Jan. 15, 2051	375	—
Unamortized discount			(30)	(24)
Unamortized debt issuance cost			(46)	(41)
Current maturities			—	(400)
Total long-term debt			$ 5,724	$ 4,985

(a) 2020 financing.
(b) 2019 financing.

SPS

Financing Instrument	Interest Rate	Maturity Date	2020	2019
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 [b]	3.75	June 15, 2049	300	300
First mortgage bonds [a]	3.15	May 1, 2050	350	—
Unamortized discount			(10)	(7)
Unamortized debt issuance cost			(26)	(23)
Total long-term debt			$ 2,764	$ 2,420

(a) 2020 financing.
(b) 2019 financing.

Other Subsidiaries

Financing Instrument	Interest Rate	Maturity Date	2020	2019
Various Eloigne affordable housing project notes	0.00% - 6.90%	2021 — 2054	$ 27	$ 28
Current maturities			(2)	(2)
Total long-term debt			$ 25	$ 26

Maturities of long-term debt:

(Millions of Dollars)	
2021	$ 421
2022	601
2023	1,151
2024	552
2025	1,102

Deferred Financing Costs — Deferred financing costs of approximately $167 million and $148 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2020 and 2019, respectively.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward equity agreements for a $459 million public offering of 9.4 million shares of Xcel Energy common stock. In August 2019, Xcel Energy settled the forward equity agreements by delivering 9.4 million shares of common equity for cash proceeds of $453 million.

In November 2019, Xcel Energy Inc. entered into forward equity agreements for a $743 million public offering of 11.8 million shares of Xcel Energy common stock. In November 2020, Xcel Energy settled the forward equity agreements by delivering 11.8 million shares of common equity for cash proceeds of $721 million.

Other Equity — Xcel Energy issued $40 million and $39 million of equity annually through the DRIP program during the years ended Dec. 31, 2020 and 2019 respectively. The program allows stockholders to elect dividend reinvestment in Xcel Energy common stock through a non-cash transaction. See Note 8 for equity items related to share based compensation.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2020 and 2019
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, 2020	Common Stock Outstanding (Shares) as of Dec. 31, 2019
1,000,000,000	$ 2.50	537,438,394	524,539,000

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, 2020:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2020
NSP-Minnesota	47.1 %	57.5 %	52.7 %
NSP-Wisconsin	52.5	N/A	52.8
SPS [a]	45.0	55.0	54.4

(a) Excludes short-term debt.

(Amounts in Millions)	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1,356	$ 12,853	$ 13,200
NSP-Wisconsin [a]	7	1,940	N/A
SPS [b]	510	6,062	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, 2020:

(Millions of Dollars)	Long-Term Debt	Short-Term Debt
NSP-Minnesota	52.93% of total capitalization [a]	$ 1,980 [a]
NSP-Wisconsin	$ 250	150
SPS	— [b]	600
PSCo	1,450	800

(a) NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization remains within the required range, and to issue short-term debt provided it does not exceed 15% of total capitalization.
(b) SPS filed for additional long-term debt authorization in December 2020.

6. Revenues

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

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

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

	Year Ended Dec. 31, 2018			
(Millions of Dollars)	**Electric**	**Natural Gas**	**All Other**	**Total**
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,919	$ 988	$ 38	$ 3,945
C&I	4,874	524	25	5,423
Other	134	—	6	140
Total retail	7,927	1,512	69	9,508
Wholesale	791	—	—	791
Transmission	523	—	—	523
Other	98	100	—	198
Total revenue from contracts with customers	9,339	1,612	69	11,020
Alternative revenue and other	380	127	10	517
Total revenues	$ 9,719	$ 1,739	$ 79	$ 11,537

7. Income Taxes

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

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

Tax Year(s)	**Expiration**
2014 - 2016	July 2021

Additionally, the statute of limitations related to the federal tax loss carryback claim referenced above 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.

In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy file a protest with the IRS. In April 2020, Xcel Energy and Appeals reached an agreement and no material adjustments were required.

In 2018, the IRS began an audit of tax years 2014 - 2016. In July 2020, Xcel Energy and the IRS reached an agreement and the related benefit was recognized.

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, 2020, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	**Year**
Colorado	2009
Minnesota	2009
Texas	2012
Wisconsin	2014

- In 2018, Wisconsin began an audit of tax years 2014 - 2016. As of Dec. 31, 2020, no material adjustments have been proposed.
- In July 2020, Minnesota began a review of the 2015 - 2018 Research and Experimentation Credits. As of Dec. 31, 2020, no material adjustments have been proposed.
- Xcel Energy had no other state income tax audits in progress for its major operating jurisdictions as of Dec. 31, 2020.

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

Unrecognized tax benefits - permanent vs. temporary:

(Millions of Dollars)	**Dec. 31, 2020**	**Dec. 31, 2019**
Unrecognized tax benefit — Permanent tax positions	$ 41	$ 35
Unrecognized tax benefit — Temporary tax positions	11	9
Total unrecognized tax benefit	$ 52	$ 44

Changes in unrecognized tax benefits:

(Millions of Dollars)	2020	2019	2018
Balance at Jan. 1	$ 44	$ 37	$ 39
Additions based on tax positions related to the current year	9	10	9
Reductions based on tax positions related to the current year	(2)	(4)	(4)
Additions for tax positions of prior years	35	1	2
Reductions for tax positions of prior years	(34)	—	(4)
Settlements with taxing authorities	—	—	(5)
Balance at Dec. 31	$ 52	$ 44	$ 37

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

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
NOL and tax credit carryforwards	$ (31)	$ (40)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $19 million and $29 million at Dec. 31, 2020 and Dec. 31, 2019, respectively.

As the IRS audit resumes and state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $27 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)	2020	2019	2018
Payable for interest related to unrecognized tax benefits at Jan. 1	$ —	$ —	$ —
Interest expense related to unrecognized tax benefits	(3)	—	—
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (3)	$ —	$ —

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2020, 2019 or 2018.

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)	2020	2019
Federal tax credit carryforwards	$ 791	$ 639
State NOL carryforwards	839	937
Valuation allowances for state NOL carryforwards	(4)	(19)
State tax credit carryforwards, net of federal detriment [(a)]	89	89
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(64)	(66)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2020 and 2019.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $17 million as of Dec. 31, 2020 and 2019.

Federal carryforward periods expire between 2031 and 2040 and state carryforward periods expire starting 2021.

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:

	2020	2019	2018
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	4.9	4.9	5.0
Increases (decreases) in tax from:			
Wind PTCs	(15.7)	(9.4)	(5.2)
Plant regulatory differences [(a)]	(7.6)	(5.8)	(6.2)
Other tax credits, net NOL & tax credit allowances	(1.2)	(1.7)	(1.7)
NOL Carryback	(0.9)	—	—
Change in unrecognized tax benefits	0.5	0.5	0.4
Other, net	(1.4)	(1.0)	(0.7)
Effective income tax rate	(0.4)%	8.5 %	12.6 %

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

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

(Millions of Dollars)	2020	2019	2018
Current federal tax benefit	$ (13)	$ (16)	$ (34)
Current state tax expense	2	4	8
Current change in unrecognized tax expense (benefit)	18	2	(6)
Deferred federal tax (benefit) expense	(89)	55	122
Deferred state tax expense	91	83	85
Deferred change in unrecognized tax (benefit) expense	(10)	5	11
Deferred ITCs	(5)	(5)	(5)
Total income tax (benefit) expense	$ (6)	$ 128	$ 181

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

(Millions of Dollars)	2020	2019	2018
Deferred tax expense excluding items below	$ 237	$ 344	$ 320
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(247)	(206)	(102)
Tax expense allocated to other comprehensive income, adoption of ASC Topic 326, adoption of ASU No. 2018-02, and other	2	5	—
Deferred tax (benefit) expense	$ (8)	$ 143	$ 218

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

(Millions of Dollars)	2020	2019
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 5,810	$ 5,474
Operating lease assets	400	449
Regulatory assets	603	598
Pension expense	176	173
Other	74	70
Total deferred tax liabilities	$ 7,063	$ 6,764
Deferred tax assets:		
Regulatory liabilities	$ 806	$ 847
Operating lease liabilities	400	449
Tax credit carryforward	880	727
NOL carryforward	37	38
NOL and tax credit valuation allowances	(64)	(67)
Other employee benefits	141	128
Deferred ITCs	13	14
Rate refund	16	26
Other	88	93
Total deferred tax assets	$ 2,317	$ 2,255
Net deferred tax liability	$ 4,746	$ 4,509

8. Share-Based Compensation

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

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

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2020	2019	2018
Granted shares	1	13	18
Grant date fair value	$ 70.26	$ 53.46	$ 44.68

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2020	31	$ 50.15
Granted	1	70.26
Forfeited	(3)	44.68
Vested	(15)	46.41
Dividend equivalents	1	66.96
Nonvested restricted stock at Dec. 31, 2020	15	56.68

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

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. A total of 0.2 million, 0.3 million, and 0.3 million time-based equity shares subject only to service conditions were granted annually in 2020, 2019 and 2018, respectively.

The performance conditions for a portion of the awards granted from 2018 to 2020 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 percent depending on achievement.

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

(Units in Thousands)	2020	2019	2018
Granted units	411	483	500
Weighted average grant date fair value	$ 62.92	$ 49.67	$ 47.60

Equity awards vested:

(Units in Thousands, Fair Value in Millions)	2020	2019	2018
Vested Units	442	464	475
Total Fair Value	$ 29	$ 29	$ 23

Changes in the nonvested portion of equity award units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2020	880	$ 48.20
Granted	411	62.92
Forfeited	(101)	53.87
Vested	(442)	47.63
Dividend equivalents	32	51.56
Nonvested Units at Dec. 31, 2020	780	55.68

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)	2020	2019	2018
Granted units	33	29	36
Weighted average grant date fair value	$ 61.61	$ 58.44	$ 45.44

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2020	725	$ 32.72
Granted	33	61.61
Units distributed	(146)	28.16
Dividend equivalents	18	67.44
Stock equivalent units at Dec. 31, 2020	630	36.28

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

TSR liability awards granted:

(In Thousands)	2020	2019	2018
Awards granted	212	225	239

TSR liability awards settled:

(Units In Thousands, Settlement Amount in Millions)	2020	2019	2018
Awards settled	476	466	482
Settlement amount (cash, common stock and deferred amounts)	$ 33	$ 25	$ 22

TSR liability awards of $27 million were settled in cash in 2020.

Share-Based Compensation Expense — Other than for restricted stock, vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target. Additionally, approximately 0.2 million, 0.3 million, and 0.3 million of equity award units were granted in 2020, 2019, and 2018, respectively, with vesting subject only to service conditions of three years.

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

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

Compensation costs related to share-based awards:

(Millions of Dollars)	2020	2019	2018
Compensation cost for share-based awards [(a)]	$ 73	$ 58	$ 45
Tax benefit recognized in income	19	15	12

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

There was approximately $51 million in 2020 and $40 million in 2019 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 1.7 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 during the period. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate diluted EPS is calculated using the treasury stock method.

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

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

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

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

Diluted common shares outstanding included common stock equivalents of 1.1 million, 1.3 million and 0.5 million shares for 2020, 2019 and 2018, respectively.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled fund investments may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third-party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. 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 an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the consolidated financial statements.

Non-Derivative Fair Value Measurements

Nuclear Decommissioning Fund

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

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

Unrealized gains for the nuclear decommissioning fund were $981 million and $706 million as of Dec. 31, 2020 and 2019, respectively, and unrealized losses were $5 million and $6 million as of Dec. 31, 2020 and 2019, respectively.

Non-derivative instruments with recurring fair value measurements:

	Dec. 31, 2020					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 40	$ 40	$ —	$ —	$ —	$ 40
Commingled funds	787	—	—	—	1,041	1,041
Debt securities	528	—	572	13	—	585
Equity securities	446	1,109	2	—	—	1,111
Total	$ 1,801	$ 1,149	$ 574	$ 13	$ 1,041	$ 2,777

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $165 million of equity investments in unconsolidated subsidiaries and $154 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2019					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 33	$ 33	$ —	$ —	$ —	$ 33
Commingled funds	733	—	—	—	935	935
Debt securities	489	—	495	13	—	508
Equity securities	485	962	2	—	—	964
Total	$ 1,740	$ 995	$ 497	$ 13	$ 935	$ 2,440

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $155 million of equity investments in unconsolidated subsidiaries and $136 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2020 and 2019, 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, 2020:

	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	$ 1	$ 116	$ 211	$ 257	$ 585

Rabbi Trusts

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

Cost and fair value of assets held in rabbi trusts:

	Dec. 31, 2020				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 32	$ 32	$ —	$ —	$ 32
Mutual funds	60	70	—	—	70
Total	$ 92	$ 102	$ —	$ —	$ 102

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

	Dec. 31, 2019				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 17	$ 17	$ —	$ —	$ 17
Mutual funds	57	65	—	—	65
Total	$ 74	$ 82	$ —	$ —	$ 82

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

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes, with changes in fair value prior to settlement recorded as other comprehensive income.

As of Dec. 31, 2020, accumulated other comprehensive loss related to settled interest rate derivatives included $6 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, 2020, Xcel Energy had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but may not be designated as qualifying hedging transactions. The classification as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms.

As of Dec. 31, 2020, Xcel Energy had no commodity contracts designated as cash flow hedges.

Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [(a)(b)]	Dec. 31, 2020	Dec. 31, 2019
MWh of electricity	87	95
MMBtu of natural gas	175	110

(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, 2020, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $130 million or 54% of this credit exposure, had investment grade credit ratings from S&P, Moody's or Fitch Ratings. Three of the 10 most significant counterparties, comprising $32 million or 13% of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $17 million or 7% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income:

(Millions of Dollars)	2020	2019	2018
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (80)	$ (60)	$ (58)
After-tax net unrealized losses related to derivatives accounted for as hedges	(10)	(23)	(5)
After-tax net realized losses on derivative transactions reclassified into earnings	5	3	3
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (85)	$ (80)	$ (60)

Impact of derivative activity:

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2020		
Derivatives designated as cash flow hedges		
Interest rate	$ (13)	$ —
Total	$ (13)	$ —
Other derivative instruments		
Electric commodity	$ —	$ (5)
Natural gas commodity	—	(13)
Total	$ —	$ (18)
Year Ended Dec. 31, 2019		
Interest rate	$ (30)	$ —
Total	$ (30)	$ —
Other derivative instruments		
Electric commodity	$ —	$ 8
Natural gas commodity	—	(9)
Total	$ —	$ (1)
Year Ended Dec. 31, 2018		
Interest rate	$ (7)	$ —
Total	$ (7)	$ —
Other derivative instruments		
Electric commodity	$ —	$ 1
Natural gas commodity	—	10
Total	$ —	$ 11

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2020			
Derivatives designated as cash flow hedges			
Interest rate	$ 7 [a]	$ —	$ —
Total	$ 7	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (1) [b]
Electric commodity	—	(3) [c]	—
Natural gas commodity	—	10 [d]	(13) [d]
Total	$ —	$ 7	$ (14)
Year Ended Dec. 31, 2019			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 [a]	$ —	$ —
Total	$ 4	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 2 [b]
Electric commodity	—	(5) [c]	—
Natural gas commodity	—	2 [d]	(7) [d]
Total	$ —	$ (3)	$ (5)
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 [a]	$ —	$ —
Total	$ 4	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 14 [b]
Electric commodity	—	(1) [c]	—
Natural gas commodity	—	(6) [d]	(4) [d]
Total	$ —	$ (7)	$ 10

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Amounts for the years ended Dec. 31, 2020 and 2019 included no settlement losses on derivatives entered to mitigate natural gas price risk for electric generation recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such losses for the year ended Dec. 31, 2018, was $1 million. Remaining settlement losses for the years ended Dec. 31, 2020, 2019 and 2018 related to natural gas operations and were recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2020, 2019 and 2018.

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, 2020 and 2019, there were $4 million and $7 million of derivative instruments in a liability position with such underlying contract provisions, respectively. Certain contracts also contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under the other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2020, there were approximately $60 million of derivative instruments in a liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. Provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2020 and 2019.

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

	Dec. 31, 2020						Dec. 31, 2019					
	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	$ 2	$ 67	$ 1	$ 70	$ (52)	$ 18	$ 3	$ 51	$ 24	$ 78	$ (52)	$ 26
Electric commodity	—	—	20	20	(1)	19	—	—	21	21	(1)	20
Natural gas commodity	—	9	—	9	—	9	—	6	—	6	—	6
Total current derivative assets	$ 2	$ 76	$ 21	$ 99	$ (53)	46	$ 3	$ 57	$ 45	$ 105	$ (53)	52
PPAs [(b)]						3						3
Current derivative instruments						$ 49						$ 55
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 8	$ 66	$ 8	$ 82	$ (62)	$ 20	$ 9	$ 38	$ 7	$ 54	$ (45)	$ 9
Total noncurrent derivative assets	$ 8	$ 66	$ 8	$ 82	$ (62)	20	$ 9	$ 38	$ 7	$ 54	$ (45)	9
PPAs [(b)]						10						13
Noncurrent derivative instruments						$ 30						$ 22

	Dec. 31, 2020						Dec. 31, 2019					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 4	$ 64	$ 17	$ 85	$ (58)	$ 27	$ 4	$ 59	$ 15	$ 78	$ (63)	$ 15
Electric commodity	—	—	1	1	(1)	—	—	—	1	1	(1)	—
Natural gas commodity	—	9	—	9	—	9	—	5	—	5	—	5
Total current derivative liabilities	$ 4	$ 73	$ 18	$ 95	$ (59)	36	$ 4	$ 64	$ 16	$ 84	$ (64)	20
PPAs [(b)]						17						18
Current derivative instruments						$ 53						$ 38
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 3	$ 58	$ 60	$ 121	$ (47)	$ 74	$ 2	$ 79	$ 32	$ 113	$ (13)	$ 100
Total noncurrent derivative liabilities	$ 3	$ 58	$ 60	$ 121	$ (47)	74	$ 2	$ 79	$ 32	$ 113	$ (13)	100
PPAs [(b)]						57						75
Noncurrent derivative instruments						$ 131						$ 175

(a) Xcel Energy nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement and all derivative instruments and related collateral amounts were subject to master netting agreements as of Dec. 31, 2020 and 2019. At Dec. 31, 2020 and 2019, derivative assets and liabilities include $15 million and $32 million of obligations to return cash collateral, respectively. At Dec. 31, 2020 and 2019, derivative assets and liabilities include rights to reclaim cash collateral of $6 million and $11 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, contracts are no longer adjusted to fair value and the previous carrying value of these contracts is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

	Year Ended Dec. 31		
(Millions of Dollars)	**2020**	**2019**	**2018**
Balance at Jan. 1	$ 4	$ 29	$ 35
Purchases	51	44	59
Settlements	(73)	(64)	(59)
Net transactions recorded during the period:			
Losses recognized in earnings [(a)]	(39)	(8)	(1)
Net gains (losses) recognized as regulatory assets and liabilities	8	3	(5)
Balance at Dec. 31	$ (49)	$ 4	$ 29

(a) Level 3 losses recognized in earnings are subject to offsetting gains of derivative instruments categorized as levels 1 and 2 in the income statement.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for Dec. 31, 2020, 2019 and 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2020		2019	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 20,066	$ 24,412	$ 18,109	$ 20,227

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, 2020 and 2019, 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 1.89, 2.82 and 3.62 percent in 2020, 2019, and 2018, 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, 2020 and 2019 were $43 million and $39 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $6 million in 2020 and $4 million in 2019.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20 years or longer period, as well as long-term projected return levels.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2020 were above the assumed level of 6.87%.
- Investment returns in 2019 were above the assumed level of 6.87%.
- Investment returns in 2018 were below the assumed level of 6.87%.
- In 2021, expected investment-return assumption is 6.49%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

	Dec. 31, 2020 (a)					Dec. 31, 2019 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 209	$ —	$ —	$ —	$ 209	$ 145	$ —	$ —	$ —	$ 145
Commingled funds	1,462	—	—	1,115	2,577	1,408	—	—	1,031	2,439
Debt securities	—	714	4	—	718	—	645	4	—	649
Equity securities	77	—	—	—	77	86	—	—	—	86
Other	13	5	—	—	18	(120)	5	—	(20)	(135)
Total	$ 1,761	$ 719	$ 4	$ 1,115	$ 3,599	$ 1,519	$ 650	$ 4	$ 1,011	$ 3,184

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

For each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2020 (a)					Dec. 31, 2019 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 27	$ —	$ —	$ —	$ 27	$ 23	$ —	$ —	$ —	$ 23
Insurance contracts	—	50	—	—	50	—	51	—	—	51
Commingled funds	72	—	—	69	141	69	—	—	76	145
Debt securities	—	232	—	—	232	—	228	1	—	229
Other	—	2	—	—	2	—	1	—	—	1
Total	$ 99	$ 284	$ —	$ 69	$ 452	$ 92	$ 280	$ 1	$ 76	$ 449

(a) See Note 10 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2020. Immaterial assets were transferred in or out of Level 3 for 2019.

Funded Status — Benefit obligations for both pension and postretirement plans increased from Dec. 31, 2019 to Dec. 31, 2020, due primarily to decreases 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)	2020	2019	2020	2019
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,701	$ 3,477	$ 547	$ 542
Service cost	95	86	1	2
Interest cost	125	145	18	22
Plan amendments	—	1	—	—
Actuarial loss	328	273	50	19
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	1	1
Benefit payments (a)	(285)	(281)	(51)	(47)
Obligation at Dec. 31	$ 3,964	$ 3,701	$ 574	$ 547
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 3,184	$ 2,742	$ 449	$ 417
Actual return on plan assets	550	568	35	56
Employer contributions	150	155	11	15
Plan participants' contributions	—	—	8	8
Benefit payments	(285)	(281)	(51)	(47)
Fair value of plan assets at Dec. 31	$ 3,599	$ 3,184	$ 452	$ 449
Funded status of plans at Dec. 31	$ (365)	$ (517)	$ (122)	$ (98)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Noncurrent assets	$ —	$ —	$ 6	$ 21
Current liabilities	—	—	(7)	(6)
Noncurrent liabilities	(365)	(517)	(121)	(113)
Net amounts recognized	$ (365)	$ (517)	$ (122)	$ (98)

(a) Includes approximately $0 million in 2020 and $20 million in 2019 of lump-sum benefit payments used in the determination of a settlement charge.

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	**2020**	**2019**	**2020**	**2019**
Discount rate for year-end valuation	2.71 %	3.49 %	2.65 %	3.47 %
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	5.50 %	6.00 %
Health care costs trend rate — initial: Post-65	N/A	N/A	5.00 %	5.10 %
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	5	3

Accumulated benefit obligation for the pension plan was $3,693 million and $3,465 million as of Dec. 31, 2020 and 2019, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income 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)	**2020**	**2019**	**2018**	**2020**	**2019**	**2018**
Service cost	$ 95	$ 86	$ 94	$ 1	$ 2	$ 2
Interest cost	125	145	133	18	22	22
Expected return on plan assets	(208)	(203)	(209)	(19)	(21)	(26)
Amortization of prior service credit	(4)	(5)	(5)	(8)	(10)	(11)
Amortization of net loss	100	87	111	4	5	8
Settlement charge [(a)]	—	6	91	—	—	—
Net periodic pension cost (credit)	108	116	215	(4)	(2)	(5)
Effects of regulation	9	(1)	(75)	3	1	2
Net benefit cost (credit) recognized for financial reporting	$ 117	$ 115	$ 140	$ (1)	$ (1)	$ (3)
Significant Assumptions Used to Measure Costs:						
Discount rate	3.49 %	4.31 %	3.63 %	3.47 %	4.32 %	3.62 %
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	6.87	6.87	6.87	4.50	4.50	5.30

(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 2019 and 2018, as a result of lump-sum distributions during each plan year, Xcel Energy recorded a total pension settlement charge of $6 million and $91 million, respectively, the majority of which was not recognized due to the effects of regulation. A total of $1 million and $11 million was recorded in the consolidated statements of income in 2019 and 2018, respectively. There were no settlement charges recorded for the qualified pension plans in 2020.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2020**	**2019**	**2020**	**2019**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 1,333	$ 1,447	$ 126	$ 95
Prior service credit	(11)	(15)	(15)	(23)
Total	$ 1,322	$ 1,432	$ 111	$ 72
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	$ 82	$ 78	$ —	$ —
Noncurrent regulatory assets	1,181	1,285	125	80
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(18)	(12)
Deferred income taxes	15	18	1	1
Net-of-tax accumulated other comprehensive income	44	51	4	4
Total	$ 1,322	$ 1,432	$ 111	$ 72
Measurement date	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019

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 2018 — 2021 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $125 million in January 2021.
- $150 million in 2020.
- $154 million in 2019.
- $150 million in 2018.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations, when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities.

Voluntary postretirement funding contributions:

- Expects to contribute approximately $10 million during 2021.
- $11 million during 2020.
- $15 million during 2019.
- $11 million during 2018.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2020	2019	2020	2019
Domestic and international equity securities	35 %	37 %	15 %	15 %
Long-duration fixed income securities	35	30	—	—
Short-to-intermediate fixed income securities	13	14	72	72
Alternative investments	15	17	9	9
Cash	2	2	4	4
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year.

Plan Amendments — In 2018, the PSCo postretirement plan was amended to add the 5% cash balance formula.

In 2019, the Pension Protection Act measurement concept was extended beyond 2019 for NSP bargaining terminations and retirements to Dec. 31, 2022.

There were no significant plan amendments made in 2020 which affected the postretirement benefit obligation.

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
2021	$ 304	$ 44	$ 2	$ 42
2022	282	43	2	41
2023	274	42	2	40
2024	265	41	2	39
2025	259	39	2	37
2026-2030	1,193	175	12	163

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $42 million in 2020, $39 million in 2019 and $38 million in 2018.

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 of such matters, including a possible eventual loss. For current proceedings not specifically reported, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are 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.

Two cases remain active which include an MDL matter consisting of a Colorado purported class (Breckenridge) and a Wisconsin purported class (Arandell Corp.).

Breckenridge/Colorado — In February 2019, the MDL panel remanded Breckenridge back to the U.S. District Court in Colorado. In December 2020, a settlement in principle was reached for approximately $3 million. The parties have sought and are awaiting court approval of settlement.

Arandell Corp. — In February 2019, the case was remanded back to the U.S. District Court in Wisconsin.

Xcel Energy has concluded that a loss is remote for the remaining lawsuit.

Rate Matters and Other

MEC Acquisition and Disposition — In January 2020, Xcel Energy, Inc. purchased MEC, a 760 MW natural gas combined cycle facility, for approximately $650 million from Southern Power Company.

In July 2020, Xcel Energy sold MEC to Southwest Generation for $684 million. The gain on sale of approximately $20 million, which was offset by charitable giving, including COVID-19 relief efforts, had no material impact on earnings.

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

In March 2019, the MPUC approved NSP-Minnesota's 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 accordance with a prior MPUC order, NSP-Minnesota made a compliance filing in August 2020 detailing all costs that resulted from the outage and all insurance recoveries received by NSP-Minnesota in connection with the outage.

In January 2021, the Minnesota Office of the Attorney General and DOC filed comments recommending that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the FCA. On Jan. 27, 2021, NSP-Minnesota filed its response, asserting that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed $22 million of related costs and no additional refund or disallowance is appropriate. A final decision by the MPUC is pending. A loss related to this matter is deemed remote.

Westmoreland Arbitration — In November 2014, insurers for Westmoreland Coal Company filed an arbitration demand against NSP-Minnesota, SMMPA and Western Fuels Association, seeking recovery of alleged business losses due to a turbine failure at Sherco Unit 3. The Westmoreland insurers claim NSP-Minnesota's invocation of the force majeure clause to stop the supply of coal was improper because the incident was allegedly caused by NSP-Minnesota's failure to conform to industry maintenance standards. Westmoreland's insurers quantified their losses as approximately $36 million.

Arbitration was delayed pending resolution of a separate lawsuit brought by NSP-Minnesota, SMMPA, and their insurers against various GE entities based on the inspection and maintenance advice GE provided for Sherco Unit 3. In July 2020, following the conclusion of the appeal that fully resolved the GE litigation, Westmoreland's insurers served notice, which triggered the arbitration to resume.

NSP-Minnesota denies the claims asserted by the Westmoreland insurers and believes it properly stopped the supply of coal based upon the force majeure provision. It is uncertain when a final resolution will occur, but it is unlikely an arbitration hearing will take place before the fourth quarter 2021. At this stage of the proceeding, before any discovery has been conducted/completed, a reasonable estimate of damages or range of damages cannot be determined.

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

In September 2016, the FERC issued an order (Opinion No. 551) granting a 10.32% base ROE effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C Circuit subsequently vacated and remanded the FERC Opinion.

In November 2019, the FERC issued an order (Opinion No. 569), which set the MISO base ROE at 9.88%, effective Sept. 28, 2016 and for the first complaint period. The FERC also dismissed the second complaint. In December 2019, MISO TOs filed a request for rehearing regarding the new ROE methodology announced in Opinion No. 569. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds.

In May 2020, the FERC issued an order (Opinion No. 569-A) which granted rehearing in part to Opinion 569 and further refined the FERC's ROE methodology, most significantly to incorporate the risk premium model (in addition to the discounted cash flow and capital asset pricing models), resulting in a new base ROE of 10.02%, effective Sept. 28, 2016 and for the first complaint period. The FERC also affirmed its decision in Opinion No. 569 to dismiss the second complaint.

In June 2020, various parties filed requests for rehearing of Opinion 569-A with the FERC. In November 2020, the FERC issued an order (Opinion No. 569-B) in response to the rehearing requests. The FERC corrected certain inputs to its ROE calculation model, did not change the ROE for the first MISO complaint period and upheld its decision to deny refunds for the second complaint period. Each 10 basis point reduction in the allowed base ROE for the first complaint and second complaint would reduce net income by $2 million and $1 million, respectively.

Various parties have filed petitions for review of Opinion Nos. 569, 569-A and 569-B at the D.C. Circuit. These appeals remain pending.

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

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

In October 2017, SPS filed a separate related complaint asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amount through future SPS customer rates. In October 2020, SPS filed a petition for review of the FERC's March 2018 order and May 2018 tolling order at the D.C. Circuit. This appeal is stayed pending the outcome of the separate appeal initiated in 2020 by Oklahoma Gas & Electric and SPP.

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, 2020, SPS does not expect refunds to be probable under either of these commitments.

Contract Termination — SPS and Lubbock Power & Light are parties to a 25-year, 170 MW partial requirements contract. In October 2020, Lubbock Power & Light initiated discussions concerning the interpretation of contractual terms related to early termination and default. If the parties are unable to reach resolution, the contract calls for the matter to proceed to arbitration. The amount of any damages depends on multiple factors and is currently unknown.

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.

MGP, Landfill and Disposal Sites

Ashland MGP Site — NSP-Wisconsin was named a responsible party for contamination at the Ashland/Northern States Power Lakefront Superfund Site (the Site) in Ashland, Wisconsin. Remediation was completed in 2019 and restoration activities were completed in 2020. Groundwater treatment activities will continue for many years.

The cost estimate for remediation and restoration of the entire site is approximately $199 million. At Dec. 31, 2020 and 2019, NSP-Wisconsin had a total liability of $19 million and $23 million, respectively, for the entire site.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation and restoration costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation and restoration costs incurred at the Site and application of a 3% carrying charge to the regulatory asset.

In January 2021, the EPA confirmed that NSP-Wisconsin completed its work on the soils and sediments at the Site and all that remains is the long-term groundwater pump and treat program.

Xcel Energy is currently investigating, remediating or performing post-closure actions at 12 other MGP, landfill or other disposal sites across its service territories.

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

Environmental Requirements — Water and Waste

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

Xcel Energy is conducting groundwater sampling and monitoring and implementing assessment of corrective measures at certain CCR landfills and surface impoundments. In NSP-Minnesota, no results above the groundwater protection standards in the rule were identified. In PSCo, statistically significant increases above background concentrations were detected at four locations. Subsequently, assessment monitoring samples were collected at these locations and, based on the results, PSCo is evaluating options for corrective action at two locations, one of which indicates potential offsite impacts to groundwater. Until PSCo completes its assessments, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows.

In August 2020, the EPA published its final rule to implement a cease receipt and initiate a closure date of April 2021 for all CCR impoundments affected by the August 2018 D.C. Circuit ruling. The D.C. Circuit concluded that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. This final rule required Xcel Energy to expedite closure plans for two impoundments.

In October 2020, NSP-Minnesota completed construction and placed in service a new impoundment to replace the clay lined impoundment at a cost of $9 million. With the new ash pond in service, NSP-Minnesota has initiated closure activities for the existing ash pond at an estimated cost of $4 million. NSP-Minnesota has five years to complete closure activities.

PSCo is pursuing options to build an alternative bottom ash collection system that will be constructed and in service in advance of the April 11, 2021 deadline. Once the alternative bottom ash system is operational, the existing impoundment will initiate closure per the CCR Rule.

Closure costs for existing impoundments are included in the calculation of the ARO.

Federal CWA WOTUS Rule — In April 2020, the EPA and U.S. Army Corps of Engineers ("Agencies") replaced the 2015 WOTUS rule and narrowed the definition of WOTUS ("2020 WOTUS Rule"). The new definition simplifies the process whether waters are subject to CWA jurisdiction and streamlines the permitting process. In June 2020, the U.S. District Court for the District of Colorado stayed the effective date of the 2020 WOTUS Rule in Colorado, where the pre-2015 definition of WOTUS is now in effect. Regardless of which definition is applicable in the states in which we operate, Xcel Energy does not anticipate that compliance costs will be material.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In October 2020, the EPA published a final rule revising the regulations.

The retirement of units affected by the final ELG rule is subject to regulatory approval. The exact total cost of ELG compliance is therefore uncertain but Xcel Energy does not anticipate that compliance costs will be material.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates the likely cost for complying with impingement and entrainment requirements is approximately $41 million, to be incurred between 2021 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain but could be up to $191 million. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. The regional haze first planning period requirements developed by Minnesota and Colorado were approved by the EPA in 2012 and implemented by 2014 and 2016, respectively. Texas' first regional haze plan has undergone federal review.

All states are now subject to a second round of regional haze planning/ rulemaking, focusing on additional reductions to meet reasonable progress requirements. Any additional impacts to Xcel Energy facilities are expected to be minimal.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking. The EPA reaffirmed the rule in August 2020 with minor changes.

The 2020 EPA Action has been challenged. All pending actions could be consolidated, and may proceed in the Fifth Circuit or the D.C. Circuit, where a parallel challenge has been filed. The timing of final decisions is unclear.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule are needed at Tolk under the "reasonable progress" requirements. As states are now proceeding with the second regional haze planning period, the EPA may choose not to act on the remanded rule.

Implementation of the NAAQS for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with an exception. The EPA issued final designations, which found the area near the SPS Harrington plant as "unclassifiable." The area near the Harrington plant was monitored for the three years ending in 2019 and the monitoring showed the area to be exceeding the standard.

To address this issue, SPS negotiated an order with the TCEQ providing for the end of coal combustion and the conversion of the Harrington plant to a natural gas fueled facility by Jan. 1, 2025.

Xcel Energy believes compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for Xcel Energy's assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning was $2.8 billion and $2.4 billion for 2020 and 2019, respectively.

Xcel Energy's AROs were as follows:

(Millions of Dollars)	Jan. 1, 2020	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2020
Electric						
Nuclear	$2,068	$ —	$ —	$ 105	$ (216)	$1,957
Steam, hydro and other production	202	—	(5)	9	58	264
Wind	146	149	(3)	8	60	360
Distribution	44	—	—	2	—	46
Natural gas						
Transmission and distribution	236	—	—	10	6	252
Miscellaneous	3	—	—	—	—	3
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,701	$ 149	$ (8)	$ 134	$ (92)	$2,884

(a) Amounts incurred related to the wind farms placed in service in 2020 for NSP-Minnesota (Blazing Star 1, Crowned Ridge 2, Jeffers and Community Wind North), PSCo (Cheyenne Ridge) and SPS (Sagamore).

(b) Amounts settled primarily related to closure of certain ash containment facilities, removal of wind facilities and asbestos abatement projects.

(c) In 2020, AROs were revised for changes in timing and estimates of cash flows. Revisions in the nuclear AROs were driven by reductions in spent fuel cooling time requirements in the nuclear triennial filing coupled with decreasing interest rates. Changes in wind AROs were driven by new dismantling studies. Revisions in steam, hydro and other production AROs were primarily related to changes in cost estimates for remediation of ash containment facilities.

(Millions of Dollars)	Jan. 1, 2019	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2019
Electric						
Nuclear	$1,968	$ —	$ —	$ 100	$ —	$ 2,068
Steam, hydro and other production	177	—	(5)	8	22	202
Wind	119	26	—	7	(6)	146
Distribution	42	—	—	2	—	44
Miscellaneous	7	—	—	—	(7)	—
Natural gas						
Transmission and distribution	249	—	—	11	(24)	236
Miscellaneous	4	—	—	—	(1)	3
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,568	$ 26	$ (5)	$ 128	$ (16)	$ 2,701

(a) Amounts incurred related to the wind farms placed in service in 2019 for NSP-Minnesota (Lake Benton and Foxtail) and SPS (Hale).

(b) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(c) In 2019, AROs were revised for changes in timing and estimates of cash flows. Revisions in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by decreased inflation rates. Changes in steam, hydro and other production AROs primarily related to changes in cost estimates to remediate ponds at production facilities. Revisions in wind AROs were driven by new dismantling studies.

Indeterminate AROs — Other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2020. Therefore, an ARO was not recorded for these facilities.

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $13.8 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.3 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to $138 million per reactor-incident for each of its three reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $21 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.8 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350 million, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage.

NSP-Minnesota could be subject to annual maximum assessments of $11 million for business interruption insurance and $34 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 47 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2095. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. The cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota had $2.8 billion of assets held in external decommissioning trusts at Dec. 31, 2020. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements as an ARO.

	Regulatory Basis	
(Millions of Dollars)	**2020**	**2019**
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	844	688
Estimated decommissioning cost obligation (in current dollars)	3,856	3,700
Effect of escalating costs to payment date	7,349	7,505
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 1.64% and 2.39% for 2020 and 2019, respectively)	(4,181)	(5,562)
Discounted decommissioning cost obligation	$ 7,024	$ 5,643
Assets held in external decommissioning trust	$ 2,777	$ 2,440
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	4,247	3,203

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	**2020**	**2019**
Discounted decommissioning cost obligation - regulated basis	$ 7,024	$ 5,643
Differences in discount rate and market risk premium	(2,628)	(2,295)
O&M costs not included for GAAP	(1,734)	(1,280)
ARO differences between 2020 and 2014 cost studies	(705)	—
Nuclear production decommissioning ARO - GAAP	$ 1,957	$ 2,068

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	**2020**	**2019**	**2018**
Annual decommissioning recorded as depreciation expense: [(a) (b)]	$ 20	$ 20	$ 20

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2020, 2019 and 2018 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2020, 2019 and 2018. Although there was a nuclear triennial filing in 2017, the MPUC continued to approve the 2014 triennial filing as the regulatory basis in 2020, 2019 and 2018. In December 2020, the MPUC verbally approved NSP-Minnesota to continue using the 2014 filing as the basis for 2021.

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 are recognized in other current liabilities and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of Xcel Energy's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the applicable Xcel Energy subsidiary's estimated incremental borrowing rate (weighted-average of 4.0%). Xcel Energy has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	**Dec. 31, 2020** [(a)]	**Dec. 31, 2019**
PPAs	$ 1,650	$ 1,642
Other	212	201
Gross operating lease ROU assets	1,862	1,843
Accumulated amortization	(372)	(171)
Net operating lease ROU assets	$ 1,490	$ 1,672

(a) In 2020, Xcel Energy purchased MEC, which was subsequently sold. During the period of ownership, the MEC PPA was not accounted for as an operating lease. Xcel Energy reestablished the operating lease ROU asset of approximately $350 million upon the sale of MEC to a third party.

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, 2020**	**Dec. 31, 2019**
Gas storage facilities	$ 201	$ 201
Gas pipeline	21	21
Gross finance lease ROU assets	222	222
Accumulated amortization	(90)	(83)
Net finance lease ROU assets	$ 132	$ 139

Components of lease expense:

(Millions of Dollars)	2020	2019	2018
Operating leases			
PPA capacity payments	$ 238	$ 221	$ 210
Other operating leases [(a)]	26	34	38
Total operating lease expense [(b)]	$ 264	$ 255	$ 248
Finance leases			
Amortization of ROU assets	$ 7	$ 6	$ 6
Interest expense on lease liability	18	19	19
Total finance lease expense	$ 25	$ 25	$ 25

(a) Includes short-term lease expense of $5 million for 2020, 2019 and 2018.

(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, 2020:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [(c)]
2021	$ 247	$ 26	$ 273	$ 14
2022	228	30	258	12
2023	218	21	239	12
2024	209	21	230	12
2025	189	15	204	10
Thereafter	561	94	655	197
Total minimum obligation	1,652	207	1,859	257
Interest component of obligation	(262)	(39)	(301)	(180)
Present value of minimum obligation	$ 1,390	168	1,558	77
Less current portion			(214)	(4)
Noncurrent operating and finance lease liabilities			$ 1,344	$ 73
Weighted-average remaining lease term in years			8.5	36.5

(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 with various expiration dates through 2033 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 contain minimum energy purchase commitments, and total energy payments on those contracts were $112 million, $102 million and $105 million in 2020, 2019 and 2018, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $75 million, $86 million and $131 million in 2020, 2019 and 2018, 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, 2020, 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)]
2021	$ 71	$ 156
2022	75	172
2023	77	176
2024	72	181
2025	29	60
Thereafter	24	85
Total	$ 348	$ 830

(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 2021 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, 2020:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2021	$ 298	$ 101	$ 453	$ 287
2022	165	87	120	280
2023	58	103	55	217
2024	24	83	3	165
2025	24	121	—	149
Thereafter	52	274	—	708
Total	$ 621	$ 769	$ 631	$ 1,806

VIEs

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. Xcel Energy has determined that certain IPPs are VIEs. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance.

The utility subsidiaries had approximately 4,062 MW and 3,986 MW of capacity under long-term PPAs at Dec. 31, 2020 and 2019, respectively, with entities that have been determined to be VIEs. Agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO Inc. under contracts that will expire in December 2022. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs.

SPS has determined that TUCO is a VIE, however it has concluded that SPS is not the primary beneficiary of TUCO because it does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing partnerships to be VIEs primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not align with the partners' proportional equity ownership.

Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance. Therefore, Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements. Xcel Energy's risk of loss for these partnerships is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be, provided to the limited partnerships by Eloigne or NSP-Wisconsin.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships:

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
Current assets	$ 7	$ 7
Property, plant and equipment, net	38	41
Other noncurrent assets	1	1
Total assets	$ 46	$ 49
Current liabilities	$ 8	$ 8
Mortgages and other long-term debt payable	25	26
Other noncurrent liabilities	1	—
Total liabilities	$ 34	$ 34

Other

Technology Agreements — Xcel Energy has several contracts for information technology services that extend through 2022. The contracts are cancelable, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $110 million, $101 million and $127 million associated with these contracts in 2020, 2019 and 2018, respectively.

Committed minimum payments under these obligations are $33 million in 2021 and $15 million in 2022.

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

As of Dec. 31, 2020 and 2019, 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 at both Dec. 31, 2020 and 2019.

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:

	2020		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (80)	$ (61)	$ (141)
Other comprehensive loss before reclassifications (net of taxes of $(3) and $(2), respectively)	(10)	(5)	(15)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $2 and $—, respectively)	5 [(a)]	—	5
Amortization of net actuarial loss (net of taxes of $— and $3, respectively)	—	10 [(b)]	10
Net current period other comprehensive (loss) income	(5)	5	—
Accumulated other comprehensive loss at Dec. 31	$ (85)	$ (56)	$ (141)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

(Millions of Dollars)	2019 Gains and Losses on Cash Flow Hedges	2019 Defined Benefit Pension and Postretirement Items	2019 Total
Accumulated other comprehensive loss at Jan. 1	$ (60)	$ (64)	$ (124)
Other comprehensive loss before reclassifications (net of taxes of $(8) and $—, respectively)	(23)	—	(23)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $1 and $—, respectively)	3 [(a)]	—	3
Amortization of net actuarial loss (net of taxes of $— and $1, respectively)	—	3 [(b)]	3
Net current period other comprehensive (loss) income	(20)	3	(17)
Accumulated other comprehensive loss at Dec. 31	$ (80)	$ (61)	$ (141)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

14. Segment Information

Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided, including the regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments:

- **Regulated Electric** — The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations.
- **Regulated Natural Gas** — The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Xcel Energy also presents All Other, which includes operating segments with revenues below the necessary quantitative thresholds. Those operating segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel, investments in rental housing projects that qualify for low-income housing tax credits and the operations of MEC until July 2020.

Xcel Energy had equity investments in unconsolidated subsidiaries of $165 million and $155 million as of Dec. 31, 2020 and 2019, 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)	2020	2019	2018
Regulated Electric			
Operating revenues - external	$ 9,802	$ 9,575	$ 9,719
Intersegment revenue	2	1	1
Total revenues	$ 9,804	$ 9,576	$ 9,720
Depreciation and amortization	1,673	1,535	1,421
Interest charges and financing costs	534	500	449
Income tax expense	1	125	187
Net income	1,407	1,288	1,177
Regulated Natural Gas			
Operating revenues - external	$ 1,636	$ 1,868	$ 1,739
Intersegment revenue	1	2	2
Total revenues	$ 1,637	$ 1,870	$ 1,741
Depreciation and amortization	252	219	212
Interest charges and financing costs	71	69	61
Income tax expense	17	48	28
Net income	190	195	187
All Other			
Total revenues	$ 88	$ 86	$ 79
Depreciation and amortization	23	11	9
Interest charges and financing costs	193	167	142
Income tax benefit	(24)	(45)	(34)
Net loss	(124)	(111)	(103)
Consolidated Total			
Total revenues	$ 11,529	$ 11,532	$ 11,540
Reconciling eliminations	(3)	(3)	(3)
Total operating revenues	$ 11,526	$ 11,529	$ 11,537
Depreciation and amortization	1,948	1,765	1,642
Interest charges and financing costs	798	736	652
Income tax (benefit) expense	(6)	128	181
Net income	1,473	1,372	1,261

15. Summarized Quarterly Financial Data (Unaudited)

(Amounts in millions, except per share data)	Quarter Ended March 31, 2020	June 30, 2020	Sept. 30, 2020	Dec. 31, 2020
Operating revenues	$ 2,811	$ 2,586	$ 3,182	$ 2,947
Operating income	455	422	813	426
Net income	295	287	603	288
EPS total — basic	$ 0.56	$ 0.54	$ 1.15	$ 0.54
EPS total — diluted	0.56	0.54	1.14	0.54
Cash dividends declared per common share	0.43	0.43	0.43	0.43

(Amounts in millions, except per share data)	Quarter Ended March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019
Operating revenues	$ 3,141	$ 2,577	$ 3,013	$ 2,798
Operating income	486	410	758	450
Net income	315	238	527	292
EPS total — basic	$ 0.61	$ 0.46	$ 1.02	$ 0.56
EPS total — diluted	0.61	0.46	1.01	0.56
Cash dividends declared per common share	0.405	0.405	0.405	0.405

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, 2020, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. 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, 2020 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.

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 2021 Annual Meeting of Shareholders, which is expected to occur on April 6, 2021, 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 2021 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 2021 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 2021 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2021 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, 2020.
	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, 2020, 2019, and 2018.
	Consolidated Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2020, 2019, and 2018.
	Consolidated Statements of Cash Flows — For each of the three years ended Dec. 31, 2020, 2019, and 2018.
	Consolidated Balance Sheets — As of Dec. 31, 2020 and 2019.
	Consolidated Statements of Common Stockholders' Equity — For each of the three years ended Dec. 31, 2020, 2019, and 2018.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2020, 2019 and 2018.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc. Form 8-K dated May 16, 2012	3.01
3.02*	Bylaws of Xcel Energy Inc. as Amended on April 3, 2020	Xcel Energy Inc. Form 8-K dated April 3, 2020	3.01
4.01*	Description of Securities	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	4.01
4.02*	Indenture dated Dec. 1, 2000 between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	4.01
4.03*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 6, 2006	4.01
4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	4.01
4.05*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	4.03
4.06*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	4.01
4.07*	Supplemental Indenture No. 8, dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 1, 2015	4.01
4.08*	Supplemental Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated March 8, 2016	4.02
4.09*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	4.01
4.10*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 25, 2018	4.01
4.11*	Supplemental Indenture No. 12, dated as of Nov. 7, 2019 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating 2.60% Senior Notes, Series Due 2029 and 3.50% Senior Notes, Series due 2049	Xcel Energy Inc. Form 8-K dated Nov. 7, 2019	4.01
4.12*	Supplemental Indenture No. 13, dated as of April 1, 2020 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association as Trustee creating $600 million principal amount of 3.40% Senior Notes, Series due 2030	Xcel Energy Inc. Form 8-K dated April 1, 2020	4.01
4.13*	Supplemental Indenture No. 14, dated as of Sept. 25, 2020 between Xcel Energy Inc. and Wells Fargo Bank, National Association as Trustee, creating $500 million principal amount of 0.50% Senior Notes, Series due Oct. 15, 2023	Xcel Energy Inc. Form 8-K dated Sept. 25, 2020	4.01
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 Award Agreement 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 Sept. 1, 2019		
10.23*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.36
10.24*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	H-1
10.25*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.01
NSP-Minnesota			
4.14*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(3)
4.15*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.11
4.16*	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.12
4.17*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.51
4.18*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(7)
4.19*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.63
4.20*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due 2035	NSP-Minnesota Form 8-K dated July 14, 2005	4.01
4.21*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due 2036	NSP-Minnesota Form 8-K dated May 18, 2006	4.01
4.22*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	4.01
4.23*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and the Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	4.01
4.24*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.95% First Mortgage Bonds, Series due 2015 and $250 principal amount of 4.85% First Mortgage Bonds, Series due 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	4.01
4.25*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	4.01
4.26*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due 2023	NSP-Minnesota Form 8-K dated May 20, 2013	4.01
4.27*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due 2044	NSP-Minnesota Form 8-K dated May 13, 2014	4.01
4.28*	Supplemental Trust Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and the Bank of New York Mellon Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	4.01
4.29*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and the Bank of NY Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.60% First Mortgage Bonds, Series due 2046	NSP-Minnesota Form 8-K dated May 31, 2016	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	4.01

4.31*	Supplemental Trust Indenture dated as of Sept. 1, 2019 between Northern States Power Company and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 2.90% First Mortgage Bonds, Series due 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	4.01
4.32*	Supplemental Indenture dated as of June 8, 2020 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $700 million principal amount of 2.60% First Mortgage Bonds, Series due 2051	NSP-Minnesota 8-K dated June 15, 2020	4.01
10.26*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.27*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.02
NSP-Wisconsin			
4.33*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust Company, providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(c)(3)
4.34*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	4.01
4.35*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375% First Mortgage Bonds, Series due 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	4.01
4.36*	Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.70% First Mortgage Bonds, Series due 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	4.01
4.37*	Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	4.01
4.38*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.75% First Mortgage Bonds, Series due 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	4.01
4.39*	Supplemental Indenture dated as of Sept. 1, 2018 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 4.20% First Mortgage Bonds, Series due 2048	NSP-Wisconsin Form 8-K dated Sept. 12, 2018	4.01
4.40*	Supplemental Indenture dated as of May 18, 2020 between NSP-Wisconsin and U.S. Bank National Association, as Trustee, creating $100 million principal amount of 3.05% First Mortgage Bonds, Series due 2051	NSP-Wisconsin Form 8-K dated May 26, 2020	4.01
10.28*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01
10.29*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.05
PSCo			
4.41*	Indenture, dated as of Oct. 1, 1993 between PSCo and Morgan Guaranty Trust Company of New York, as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(d)(3)
4.42*	Supplemental Indenture, dated Aug. 1, 2007 between PSCo and U.S. Bank Trust National Association, as successor Trustee	PSCo Form 8-K dated Aug. 8, 2007	4.01
4.43*	Supplemental Indenture dated as of Aug. 1, 2008 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80% First Mortgage Bonds, Series due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series due 2038	PSCo Form 8-K dated Aug. 6, 2008	4.01
4.44*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75% First Mortgage Bonds, Series due 2041	PSCo Form 8-K dated Aug. 9, 2011	4.01
4.45*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series due 2042	PSCo Form 8-K dated Sept. 11, 2012	4.01
4.46*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50% First Mortgage Bonds, Series due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series due 2043	PSCo Form 8-K dated March 26, 2013	4.01
4.47*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30% First Mortgage Bonds, Series due 2044	PSCo Form 8-K dated March 10, 2014	4.01
4.48*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.90% First Mortgage Bonds, Series due 2025	PSCo Form 8-K dated May 12, 2015	4.01
4.49*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 3.55% First Mortgage Bonds, Series due 2046	PSCo Form 8-K dated June 13, 2016	4.01
4.50*	Supplemental Indenture dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.80% First Mortgage Bonds, Series due 2047	PSCo Form 8-K dated June 19, 2017	4.01
4.51*	Supplemental Indenture dated as of June 1, 2018 between PSCo and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70% First Mortgage Bonds, Series due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series due 2048	PSCo Form 8-K dated June 21, 2018	4.01
4.52*	Supplemental Indenture dated as of March 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 4.05% First Mortgage Bonds, Series due 2049	PSCo Form 8-K dated March 13, 2019	4.01
4.53*	Supplemental Indenture dated as of Aug. 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $550 million principal amount of 3.20% First Mortgage Bonds, Series due 2050	PSCo Form 8-K dated August 13, 2019	4.01
4.54*	Supplemental Indenture dated as of May 1, 2020 between PSCo and U.S. Bank National Association, as successor Trustee, creating $375 million principal of 2.70% First Mortgage Bonds, Series No. 35 due 2051 and $375 million principal amount of 1.90% First Mortgage Bonds, Series No. 36 due 2031	PSCo Form 8-K dated May 15, 2020	4.01
10.30*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	99.02

10.31*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.03
SPS			
4.55*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	99.2
4.56*	Supplemental Indenture dated Oct. 1, 2003 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6% due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	4.04
4.57*	Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee, creating $200 million principal amount of 5.6% Series E Notes due 2016 and $250 million principal amount of 6% Series F Notes due 2036	SPS Form 8-K dated Oct. 3, 2006	4.01
4.58*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	4.01
4.59*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series due 2041	SPS Form 8-K dated Aug. 10, 2011	4.02
4.60*	Supplemental Indenture dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	SPS Form 8-K dated June 9, 2014	4.02
4.61*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series due 2046	SPS Form 8-K dated Aug. 12, 2016	4.02
4.62*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series due 2047	SPS Form 8-K dated Aug 9. 2017	4.02
4.63*	Supplemental Indenture dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 4.40% First Mortgage Bonds, Series due 2048	SPS Form 8-K dated Nov. 5, 2018	4.02
4.64*	Supplemental Indenture dated as of June 1, 2019 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.75% First Mortgage Bonds, Series due 2049	SPS Form 8-K dated June 18, 2019	4.02
4.65*	Supplemental Indenture No. 8, dated as of May 1, 2020 between SPS and U.S. Bank National Association, as Trustee, creating $350 million principal amount of 3.15% First Mortgage Bonds, Series due 2050	SPS Form 8-K dated May 18, 2020	4.02
10.32*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	99.04

Xcel Energy Inc.	
21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm
24.01	Powers of Attorney
31.01	Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.02	Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH	Inline XBRL Schema
101.CAL	Inline XBRL Calculation
101.DEF	Inline XBRL Definition
101.LAB	Inline XBRL Label
101.PRE	Inline XBRL Presentation
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

SCHEDULE I

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

	Year Ended Dec. 31		
	2020	2019	2018
Income			
Equity earnings of subsidiaries	$ 1,646	$ 1,505	$ 1,393
Total income	1,646	1,505	1,393
Expenses and other deductions			
Operating expenses	43	23	24
Other income	(4)	(9)	(1)
Interest charges and financing costs	198	173	149
Total expenses and other deductions	237	187	172
Income before income taxes	1,409	1,318	1,221
Income tax benefit	(64)	(54)	(40)
Net income	$ 1,473	$ 1,372	$ 1,261
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $ 1, $1 and $1, respectively	$ 5	$ 3	$ 3
Derivative instruments, net of tax of $(1), $(7) and $(1), respectively	(5)	(20)	(2)
Other comprehensive income (loss)	—	(17)	1
Comprehensive income	$ 1,473	$ 1,355	$ 1,262
Weighted average common shares outstanding:			
Basic	527	519	511
Diluted	528	520	511
Earnings per average common share:			
Basic	$ 2.79	$ 2.64	$ 2.47
Diluted	2.79	2.64	2.47

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2020	2019	2018
Operating activities			
Net cash provided by operating activities	$ 2,377	$ 1,389	$ 1,210
Investing activities			
Capital contributions to subsidiaries	(2,553)	(1,594)	(809)
Net (investments) return in the utility money pool	(18)	39	(85)
Other, net	(1)	—	—
Net cash used in investing activities	(2,572)	(1,555)	(894)
Financing activities			
(Repayment of) proceeds from short-term borrowings, net	(500)	12	(295)
Proceeds from issuance of long-term debt	1,089	1,120	492
Repayment of long-term debt	(300)	(550)	—
Proceeds from issuance of common stock	727	458	230
Repurchase of common stock	(4)	—	(1)
Dividends paid	(856)	(791)	(730)
Other	(17)	(14)	(12)
Net cash provided by (used in) financing activities	139	235	(316)
Net change in cash and cash equivalents	(56)	69	—
Cash and cash equivalents at beginning of period	70	1	1
Cash and cash equivalents at end of period	$ 14	$ 70	$ 1

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2020	2019
Assets		
Cash and cash equivalents	$ 14	$ 70
Accounts receivable from subsidiaries	424	370
Other current assets	6	12
Total current assets	444	452
Investment in subsidiaries	19,102	17,443
Other assets	40	60
Total other assets	19,142	17,503
Total assets	$ 19,586	$ 17,955
Liabilities and Equity		
Current portion of long-term debt	400	—
Dividends payable	231	212
Short-term debt	—	500
Other current liabilities	21	33
Total current liabilities	652	745
Other liabilities	17	23
Total other liabilities	17	23
Commitments and contingencies		
Capitalization		
Long-term debt	4,342	3,948
Common stockholders' equity	14,575	13,239
Total capitalization	18,917	17,187
Total liabilities and equity	$ 19,586	$ 17,955

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, 2020 and 2019, 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, 2020:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of loan for Hiawatha Collegiate High School [a]	Xcel Energy Inc.	$ 1	—	[c]
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries [b]	Xcel Energy Inc.	60	[e]	[d]

[a] The term of this guarantee expires the earlier of 2024 or full repayment of the loan.
[b] The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.
[c] Nonperformance and/or nonpayment.
[d] Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.
[e] Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. provides indemnifications through contracts entered into in the normal course of business. Indemnifications are primarily against adverse litigation outcomes in connection with underwriting agreements, breaches of representations and warranties, including corporate existence, transaction authorization and certain income tax matters. Obligations under these agreements may be limited in terms of duration or amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Related Party Transactions — Xcel Energy Inc. presents related party receivables net of payables. Accounts receivable net of payables with affiliates at Dec. 31:

(Millions of Dollars)	2020	2019
NSP-Minnesota	$ 81	$ 60
NSP-Wisconsin	9	17
PSCo	98	78
SPS	55	47
Xcel Energy Services Inc.	159	112
Xcel Energy Ventures Inc.	—	25
Other subsidiaries of Xcel Energy Inc.	22	31
	$ 424	$ 370

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $2,527 million, $2,987 million and $1,097 million for the years ended Dec. 31, 2020, 2019 and 2018, 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, 2020
Loan outstanding at period end	$ 57
Average loan outstanding	185
Maximum loan outstanding	318
Weighted average interest rate, computed on a daily basis	0.08 %
Weighted average interest rate at end of period	0.07 %
Money pool interest income	$ —

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2020	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Loan outstanding at period end	$ 57	$ 39	$ —
Average loan outstanding	104	47	71
Maximum loan outstanding	350	250	243
Weighted average interest rate, computed on a daily basis	0.60 %	2.15 %	1.95 %
Weighted average interest rate at end of period	0.07 %	1.63 %	N/A
Money pool interest income	$ 1	$ 1	$ 1

See notes to the consolidated financial statements in Part II, Item 8.

SCHEDULE II

Xcel Energy Inc. and Subsidiaries Valuation and Qualifying Accounts
Years Ended Dec. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2020	2019	2018	2020	2019	2018
Balance at Jan. 1	$ 55	$ 55	$ 52	$ 67	$ 79	$ 77
Additions charged to costs and expenses	60	42	42	6	9	7
Additions charged to other accounts	12 [a]	16 [a]	11 [a]	—	—	—
Deductions from reserves	(48) [b]	(58) [b]	(50) [b]	(9) [c]	(21) [d]	(5) [d]
Balance at Dec. 31	$ 79	$ 55	$ 55	$ 64	$ 67	$ 79

[a] Recovery of amounts previously written-off.
[b] Deductions related primarily to bad debt write-offs.
[c] Primarily the reduction of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability forecasted to be used prior to expiration along with valuation allowances that expired.
[d] Primarily reductions to valuation allowances due to additional NOLs and tax credits forecasted to be used prior to expiration.

ITEM 16 — FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 17, 2021	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/ BEN FOWKE Ben Fowke	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Senior Vice President, Controller (Principal Accounting Officer)
*	Lynn Casey	Director
*	Netha N. Johnson	Director
*	Patricia L. Kampling	Director
*	George J. Kehl	Director
*	Richard T. O'Brien	Director
*	David K. Owens	Director
*	Charles Pardee	Director
*	Christopher J. Policinski	Director
*	James Prokopanko	Director
*	James J. Sheppard	Director
*	David A. Westerlund	Director
*	Kim Williams	Director
*	Timothy V. Wolf	Director
*	Daniel Yohannes	Director
*By:	/s/ BRIAN J. VAN ABEL Brian J. Van Abel	Attorney-in-Fact

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 Xcel Energy's Report to Shareholders, are available online at xcelenergy.com; click on Investor Relations. Other information about Xcel Energy, including our Code of Conduct, Guidelines on Corporate Governance, Corporate Responsibility 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: xcelenergy.com or contact Paul Johnson,
Vice President, Investor Relations, at 612-215-4535.

SHAREHOLDER SERVICES
Website: xcelenergy.com or contact Darin Norman,
Senior Analyst, 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 2020.

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
Wells Fargo Bank, N.A.,
Corporate Trust Services
600 South 4th Street
Minneapolis, MN 55415