Otter Tail Power Company
North Dakota General Rate Case Documents
Case No. PU-23-342

Supplemental Volume 3
Required Information

Volume 3

A. Jurisdictional Financial Summary Schedules

DEFINITIONS

The following definitions have been used by Otter Tail Power Company in this filing:

Most Recent Fiscal Year 2022
The Most Recent Fiscal Year presents actual normalized results for the calendar year ended December 31, 2022.

Projected Fiscal Year 2023
The Projected Fiscal year presents actual results through July 31, 2023 and projected financial information through December 31, 2023.

Unadjusted Year 2024
The Unadjusted Year presents projected financial information for the calendar year ending December 31, 2024 before required adjustments.

Regulatory Year 2024
The Regulatory Year presents projected financial information for the calendar year ending December 31, 2024 after required adjustments. The required adjustments incorporate compliance obligations from prior North Dakota rate cases as well as other regulatory adjustments.

Test Year 2024
The Test Year presents projected financial information for the calendar year ending December 31, 2021 after required adjustments and rate case adjustments. The rate case adjustments normalize the Regulatory Year for known and measurable changes expected to occur during the calendar year 2024.

Note on Rounding:
The cost of service study on which these supporting schedules are based rounds numbers to the nearest whole dollar for display purposes. However, the subtotals and subsequent totals in the cost of service study may be based on actual values resulting in occasional differences in the totals displayed and the sum of the line items. These supporting schedules were prepared using individual line items with subtotals and totals calculated on each schedule. This may result in occasional differences of a few dollars between the subtotals and totals on the cost of service study and those on supporting schedules.

Line No.	Description	North Dakota Jurisdiction Test Year 2024
1	Average Rate Base	$695,424,813
2	Total Available for Return (Line 2 + Line 3 + Rounding)	$19,989,880
3	Overall Rate of Return (Line 4 / Line 1)	2.87%
4	Required Rate of Return	7.85%
5	Operating Income Requirement (Line 1 x Line 6)	$54,590,848
6	Income Deficiency (Line 7 - Line 4)	$34,600,968
7	Gross Revenue Conversion Factor	1.322837
8	Revenue Deficiency (Line 8 x Line 9)	$45,771,443

Line No.	Description	(A) Most Recent Actual Year 2022	(B) Current Period 2023	(C) Unadjusted Year 2024	(D) Regulatory Year 2024	(E) Test Year 2024
1	Average Rate Base	$557,200,061	$587,918,709	$764,291,404	$651,646,255	$695,424,813
2	Total Available for Return (Line 2 + Line 3 + Rounding)	$35,187,011	$38,783,318	$54,305,184	$42,604,666	$19,989,880
3	Overall Rate of Return (Line 4 / Line 1)	6.31%	6.60%	7.11%	6.54%	2.87%
4	Required Rate of Return	7.26%	7.33%	7.85%	7.41%	7.85%
5	Operating Income Requirement (Line 1 x Line 6)	$40,452,724	$43,094,441	$59,996,875	$48,286,988	$54,590,848
6	Income Deficiency (Line 7 - Line 4)	$5,265,714	$4,311,124	$5,691,691	$5,682,322	$34,600,968
7	Gross Revenue Conversion Factor	1.322837	1.322837	1.322837	1.322837	1.32284
8	Revenue Deficiency (Line 8 x Line 9)	$6,965,681	$5,702,914	$7,529,180	$7,516,785	$45,771,443

Volume 3

B. Rate Base Schedules

RATE BASE SUMMARY

Line No.	Description	(A) Most Recent Actual Year 2022	(B) Current Period 2023	(C) Unadjusted Year 2024	(D) Regulatory Year 2024	(E) Test Year 2024
1	Electric Plant in Service	$1,041,850,025	$1,148,337,185	$1,383,994,446	$1,249,259,535	$1,251,434,477
2	Less: Accumulated Depreciation	(391,231,179)	(425,710,645)	(471,566,834)	(461,085,772)	(461,390,296)
3	Net Electric Plant in Service	$650,618,846	$722,626,540	$912,427,612	$788,173,763	$790,044,182
	Other Rate Base Components:					
4	Plant Held for Future Use	$12,897	$4,946	$4,921	$4,921	$4,921
5	Construction Work in Progress	7,674,957	634,580	780,990	780,990	780,993
6	Materials and Supplies	12,184,922	14,123,849	14,737,248	14,737,248	14,737,429
7	Fuel Stocks	4,092,023	4,485,687	4,495,117	4,495,117	4,495,117
8	Prepayments	9,181,902	16,979,263	18,601,559	18,601,559	18,607,498
9	Customer Advances	(572,270)	(679,093)	(709,657)	(709,657)	(709,884)
10	Cash Working Capital	2,530,836	1,920,969	1,304,936	1,304,936	1,531,800
11	Accumulated Deferred Income Taxes	(128,524,052)	(172,178,032)	(187,351,323)	(175,742,621)	(134,067,242)
12	TOTAL	$557,200,061	$587,918,709	$764,291,404	$651,646,255	$695,424,813

DETAILED RATE BASE COMPONENTS
Unadjusted Year 2024 to Regulatory Year 2024

		Total Utility			North Dakota Jurisdiction		
		(A)	(B)	(C) (A) + (B)	(D)	(E)	(F) (D) + (E)
Line No.	Description	**Unadjusted Year 2024**	Adjustments	**Regulatory Year 2024**	**Unadjusted Year 2024**	Adjustments	**Regulatory Year 2024**
	Utility Plant in Service:						
1	Production	$1,531,429,786	($61,800,001)	$1,469,629,785	$658,582,109	($26,462,276)	$632,119,833
2	Transmission	824,710,618	0	824,710,618	323,246,976	(107,426,123)	215,820,853
3	Distribution	719,466,879	(1,771,350)	717,695,529	330,597,673	(846,511)	329,751,162
4	General	122,942,613	0	122,942,613	53,300,696	0	53,300,696
5	Intangible	42,134,377	0	42,134,377	18,266,991	0	18,266,991
6	**TOTAL Utility Plant in Service**	$3,240,684,273	($63,571,351)	$3,177,112,922	$1,383,994,445	($134,734,910)	$1,249,259,535
	Accumulated Depreciation						
7	Production	($572,922,222)	$1,328,464	($571,593,758)	($246,215,224)	$568,838	($245,646,386)
8	Transmission	(184,915,987)	0	(184,915,987)	(72,478,191)	9,869,564	(62,608,627)
9	Distribution	(268,634,254)	92,846	(268,541,408)	(123,426,235)	42,659	(123,383,576)
10	General	(50,534,998)	0	(50,534,998)	(21,909,007)	0	(21,909,007)
11	Intangible	(17,387,448)	0	(17,387,448)	(7,538,176)	0	(7,538,176)
12	**TOTAL Accumulated Depreciation**	($1,094,394,909)	$1,421,310	($1,092,973,599)	($471,566,833)	$10,481,061	($461,085,772)
13	**NET Utility Plant in Service**						
14	Production	$958,507,564	($60,471,537)	$898,036,027	$412,366,885	($25,893,438)	$386,473,447
15	Transmission	639,794,631	0	639,794,631	250,768,785	(97,556,559)	153,212,226
16	Distribution	450,832,625	(1,678,504)	449,154,121	207,171,438	(803,852)	206,367,586
17	General	72,407,615	0	72,407,615	31,391,689	0	31,391,689
18	Intangible	24,746,929	0	24,746,929	10,728,815	0	10,728,815
19	**NET Utility Plant in Service**	$2,146,289,364	($62,150,041)	$2,084,139,323	$912,427,612	($124,253,849)	$788,173,763
20							
21	Utility Plant Held for Future Use	12,038	0	12,038	4,921	$0	4,921
22	Construction Work in Progress	1,770,919	0	1,770,919	780,990	0	780,990
23	Materials and Supplies	33,967,093	0	33,967,093	14,737,248	0	14,737,248
24	Fuel Stocks	10,476,711	0	10,476,711	4,495,117	0	4,495,117
25	Prepayments	49,187,428	0	49,187,428	18,601,559	0	18,601,559
26	Customer Advances & Deposits	(1,876,522)	0	(1,876,522)	(709,657)	0	(709,657)
27	Cash Working Capital	3,093,533	0	3,093,533	1,304,936	0	1,304,936
28	Accumulated Deferred Income Taxes	(371,653,654)	6,140,298	(365,513,356)	(187,351,323)	11,608,702	(175,742,621)
29	**Total Average Rate Base**	$1,871,266,910	($56,009,743)	$1,815,257,167	$764,291,404	($112,645,147)	$651,646,255

DETAILED RATE BASE COMPONENTS
Regulatory Year 2024 to Test Year 2024

		Total Utility			North Dakota Jurisdiction		
		(A)	(B)	(C) (A) + (B)	(D)	(E)	(F) (D) + (E)
Line No.	Description	**Regulatory Year 2024**	Adjustments	**Test Year 2024**	**Regulatory Year 2024**	Adjustments	**Test Year 2024**
	Utility Plant in Service:						
1	Production	$1,469,629,785	$4,982,098	$1,474,611,883	$632,119,833	$2,173,773	$634,293,606
2	Transmission	$824,710,618	0	824,710,618	$215,820,853	(0)	215,820,853
3	Distribution	$717,695,529	(1)	717,695,528	$329,751,162	(0)	329,751,162
4	General	$122,942,613	0	122,942,613	$53,300,696	876	53,301,572
5	Intangible	$42,134,377	0	42,134,377	$18,266,991	300	18,267,291
6	**TOTAL Utility Plant in Service**	$3,177,112,922	$4,982,097	$3,182,095,019	$1,249,259,535	$2,174,948	$1,251,434,483
	Accumulated Depreciation						
7	Production	($571,593,758)	($1,328,464)	($572,922,222)	($245,646,386)	($304,040)	($245,950,426)
8	Transmission	($184,915,987)	0	(184,915,987)	($62,608,627)	1	(62,608,627)
9	Distribution	($268,541,408)	(92,846)	(268,634,254)	($123,383,576)	(0)	(123,383,576)
10	General	($50,534,998)	(1)	(50,534,999)	($21,909,007)	(360)	(21,909,367)
11	Intangible	($17,387,448)	0	(17,387,448)	($7,538,176)	(124)	(7,538,300)
12	**TOTAL Accumulated Depreciation**	($1,092,973,599)	($1,421,311)	($1,094,394,910)	($461,085,772)	($304,524)	($461,390,296)
13	**NET Utility Plant in Service**						
14	Production	$898,036,027	$3,653,634	$901,689,661	$386,473,447	$1,869,733	$388,343,180
15	Transmission	639,794,631	0	639,794,631	153,212,226	0	153,212,226
16	Distribution	449,154,121	(92,847)	449,061,274	206,367,586	(0)	206,367,586
17	General	72,407,615	(1)	72,407,614	31,391,689	515	31,392,204
18	Intangible	24,746,929	0	24,746,929	10,728,815	176	10,728,991
19	**NET Utility Plant in Service**	$2,084,139,323	$3,560,786	$2,087,700,109	$788,173,763	$1,870,424	$790,044,187
20							
21	Utility Plant Held for Future Use	12,038	0	12,038	4,921	$0	4,921
22	Construction Work in Progress	1,770,919	0	1,770,919	780,990	3	780,993
23	Materials and Supplies*	33,967,093	0	33,967,093	14,737,248	181	14,737,429
24	Fuel Stocks*	10,476,711	0	10,476,711	4,495,117	0	4,495,117
25	Prepayments*	49,187,428	0	49,187,428	18,601,559	5,939	18,607,498
26	Customer Advances & Deposits*	(1,876,522)	0	(1,876,522)	(709,657)	(227)	(709,884)
27	Cash Working Capital*	3,093,533	696,021	3,789,554	1,304,936	226,864	1,531,800
28	Accumulated Deferred Income Taxes	(365,513,356)	(6,140,295)	(371,653,651)	(175,742,621)	41,675,379	(134,067,242)
29	**Total Average Rate Base**	$1,815,257,167	($1,883,488)	$1,813,373,679	$651,646,255	$43,778,563	$695,424,818

* Test Year 2024 further breakdown of these line items provided on Schedules B-2-a through B-2-e

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS

Case No. PU-23-342
Supplemental Exhibit ___ (CLP-1), Schedule B-2
Page 3 of 3

		Most Recent Actual Year 2022		Current Period 2023		Unadjusted Year 2024		Regulatory Year 2024		Test Year 2024	
Line No.	Description	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction
	Utility Plant in Service:										
1	Production	$1,336,122,578	$535,749,544	$1,396,605,647	$586,915,725	$1,531,429,786	$658,582,109	$1,469,629,785	$632,119,833	$1,474,611,883	$634,293,606
2	Transmission	740,489,372	176,329,995	783,387,503	201,891,226	824,710,618	323,246,976	824,710,618	215,820,853	824,710,618	215,820,853
3	Distribution	594,253,855	271,503,168	650,211,687	295,374,578	719,466,879	330,597,673	717,695,529	329,751,162	717,695,528	329,751,162
4	General	106,022,339	44,822,076	113,108,289	48,655,555	122,942,613	53,300,696	122,942,613	53,300,696	122,942,613	53,301,572
5	Intangible	31,803,435	13,445,242	36,032,678	15,500,101	42,134,377	18,266,991	42,134,377	18,266,991	42,134,377	18,267,291
6	**TOTAL Utility Plant in Service**	$2,808,691,579	$1,041,850,025	$2,979,345,804	$1,148,337,185	$3,240,684,273	$1,383,994,445	$3,177,112,922	$1,249,259,535	$3,182,095,019	$1,251,434,483
	Accumulated Depreciation										
7	Production	($496,007,422)	($198,091,298)	($532,171,819)	($223,294,613)	($572,922,222)	($246,215,224)	($571,593,758)	($245,646,386)	($572,922,222)	($245,950,426)
8	Transmission	(162,557,514)	(55,287,297)	(172,887,875)	(58,938,653)	(184,915,987)	(72,478,191)	(184,915,987)	(62,608,627)	(184,915,987)	(62,608,627)
9	Distribution	(250,696,398)	(114,538,367)	(258,590,450)	(117,471,043)	(268,634,254)	(123,426,235)	(268,541,408)	(123,383,576)	(268,634,254)	(123,383,576)
10	General	(44,990,981)	(19,020,418)	(47,310,391)	(20,351,411)	(50,534,998)	(21,909,007)	(50,534,998)	(21,909,007)	(50,534,999)	(21,909,367)
11	Intangible	(10,156,573)	(4,293,800)	(13,145,854)	(5,654,924)	(17,387,448)	(7,538,176)	(17,387,448)	(7,538,176)	(17,387,448)	(7,538,300)
12	**TOTAL Accumulated Depreciation**	($964,408,888)	($391,231,180)	($1,024,106,389)	($425,710,644)	($1,094,394,909)	($471,566,833)	($1,092,973,599)	($461,085,772)	($1,094,394,910)	($461,390,296)
13	**NET Utility Plant in Service**										
14	Production	$840,115,156	$337,658,246	$864,433,828	$363,621,112	$958,507,564	$412,366,885	$898,036,027	$386,473,447	$901,689,661	$388,343,180
15	Transmission	577,931,858	121,042,698	610,499,628	142,952,573	639,794,631	250,768,785	639,794,631	153,212,226	639,794,631	153,212,226
16	Distribution	343,557,457	156,964,801	391,621,237	177,903,535	450,832,625	207,171,438	449,154,121	206,367,586	449,061,274	206,367,586
17	General	61,031,358	25,801,658	65,797,898	28,304,144	72,407,615	31,391,689	72,407,615	31,391,689	72,407,614	31,392,204
18	Intangible	21,646,862	9,151,442	22,886,824	9,845,177	24,746,929	10,728,815	24,746,929	10,728,815	24,746,929	10,728,991
19	**NET Utility Plant in Service**	$1,844,282,691	$650,618,845	$1,955,239,415	$722,626,541	$2,146,289,364	$912,427,612	$2,084,139,323	$788,173,763	$2,087,700,109	$790,044,187
20											
21	Utility Plant Held for Future Use	$29,657	$12,897	$12,038	$4,946	$12,038	$4,921	$12,038	$4,921	$12,038	$4,921
22	Construction Work in Progress	118,508,484	7,674,957	1,457,475	634,580	1,770,919	780,990	1,770,919	780,990	1,770,919	780,993
23	Materials and Supplies	29,231,708	12,184,922	33,021,316	14,123,849	33,967,093	14,737,248	33,967,093	14,737,248	33,967,093	14,737,429
24	Fuel Stocks	10,354,598	4,092,023	10,744,901	4,485,687	10,476,711	4,495,117	10,476,711	4,495,117	10,476,711	4,495,117
25	Prepayments	26,027,563	9,181,902	45,941,469	16,979,263	49,187,428	18,601,559	49,187,428	18,601,559	49,187,428	18,607,498
26	Customer Advances & Deposits	(1,622,191)	(572,270)	(1,837,448)	(679,093)	(1,876,522)	(709,657)	(1,876,522)	(709,657)	(1,876,522)	(709,884)
27	Cash Working Capital	7,071,458	2,530,836	5,015,552	1,920,969	3,093,533	1,304,936	3,093,533	1,304,936	3,789,554	1,531,800
28	Accumulated Deferred Income Taxes	(321,704,219)	(128,524,052)	(358,163,575)	(172,178,032)	(371,653,654)	(187,351,323)	(365,513,356)	(175,742,621)	(371,653,651)	(134,067,242)
29	**Total Average Rate Base**	$1,712,179,749	$557,200,061	$1,691,431,142	$587,918,709	$1,871,266,910	$764,291,404	$1,815,257,167	$651,646,255	$1,813,373,679	$695,424,818

DETAILED RATE BASE COMPONENTS
MATERIALS AND SUPPLIES

Line No.				Test Year 2024 Production	(1) All Other	Total
1	December	End	2023	$8,678,324	$24,536,279	$33,214,603
2	January	End	2024	8,625,181	25,398,450	34,023,631
3	February	End	2024	8,625,181	25,790,810	34,415,991
4	March	End	2024	8,625,181	25,718,261	34,343,442
5	April	End	2024	8,625,181	25,729,957	34,355,138
6	May	End	2024	8,625,181	26,981,545	35,606,726
7	June	End	2024	8,625,181	21,827,241	30,452,422
8	July	End	2024	8,625,181	22,525,377	31,150,558
9	August	End	2024	8,625,181	23,498,736	32,123,917
10	September	End	2024	8,625,181	23,518,987	32,144,168
11	October	End	2024	8,625,181	23,308,590	31,933,771
12	November	End	2024	8,625,181	24,807,773	33,432,954
13	December	End	2024	8,625,181	26,094,401	34,719,582
14	Total			$112,180,496	$319,736,407	$431,916,903
15	Simple Average - total utility			$8,651,753	$25,315,340	$33,967,093
16						

				Test Year 2024	
23	**NORTH DAKOTA JURISDICTION**				
24		**Total**	**Allocator**	**ND Percent**	**ND Dollars**
27	Production Total	$8,651,753	P10	43.014%	$3,721,488
28	Transmission	9,116,226	D2	39.195%	3,573,123
29	Distribution	16,199,114	P60	45.946%	7,442,817
30		$33,967,093			**$14,737,429**

OTTER TAIL POWER COMPANY **Case No. PU-23-342**
Electric Utility - State of North Dakota **Supplemental Exhibit ___ (CLP-1), Schedule B-2-b**
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
FUEL STOCKS

Line No.				Test Year 2024 Coal	Oil	Total
1	December	End	2023	$8,165,846	$2,323,365	$10,489,211
2	January	End	2024	8,165,846	2,298,365	$10,464,211
3	February	End	2024	8,165,846	2,298,365	$10,464,211
4	March	End	2024	8,165,846	2,298,365	$10,464,211
5	April	End	2024	8,165,846	2,298,365	$10,464,211
6	May	End	2024	8,165,846	2,298,365	$10,464,211
7	June	End	2024	8,165,846	2,298,365	$10,464,211
8	July	End	2024	8,165,846	2,298,365	$10,464,211
9	August	End	2024	8,165,846	2,298,365	$10,464,211
10	September	End	2024	8,165,846	2,298,365	$10,464,211
11	October	End	2024	8,165,846	2,298,365	$10,464,211
12	November	End	2024	8,165,846	2,298,365	$10,464,211
13	December	End	2024	8,165,846	2,298,365	$10,464,211
14	Total			$106,155,998	$29,903,745	$136,059,743
15	Simple Average - total utility			$8,165,846	$2,310,865	$10,476,711
16						
17						

				Proposed Test Year 2024	
18	**NORTH DAKOTA JURISDICTION**				
19		**Total**	**Allocator**	**ND Percent**	**ND Dollars**
20	Coal	$8,165,846	E1	43.874%	$3,582,673
21	Fuel Oil	2,310,865	D1	39.485%	912,443
22		$10,476,711			**$4,495,117**

OTTER TAIL POWER COMPANY | **Case No. PU-23-342**
Electric Utility - State of North Dakota | **Supplemental Exhibit ___ (CLP-1), Schedule B-2-c**
RATE BASE SCHEDULES | **Page 1 of 1**
DETAILED RATE BASE COMPONENTS
PREPAYMENTS

Line No.				Prepaid Insurance & Interest	Post Retirement Benefits other than Pension (FAS 106)	Post Employment Benefits	FAS 87 Pension Plan	Total
				Test Year 2024				
1	December	End	2023	$3,575,802	($46,278,434)	($1,504,693)	$91,904,839	$47,697,514
2	January	End	2024	5,550,440	(45,650,955)	(1,520,495)	91,522,964	$49,901,953
3	February	End	2024	5,016,802	(45,023,476)	(1,536,298)	91,141,089	$49,598,117
4	March	End	2024	4,483,190	(44,395,997)	(1,552,101)	90,759,214	$49,294,306
5	April	End	2024	8,594,130	(43,768,518)	(1,567,903)	90,377,339	$53,635,047
6	May	End	2024	7,984,311	(43,141,039)	(1,583,706)	89,995,464	$53,255,030
7	June	End	2024	7,375,084	(42,513,560)	(1,599,508)	89,613,589	$52,875,605
8	July	End	2024	6,802,711	(41,886,081)	(1,615,309)	89,231,714	$52,533,034
9	August	End	2024	6,194,067	(41,258,602)	(1,631,111)	88,849,839	$52,154,193
10	September	End	2024	5,585,946	(40,631,123)	(1,646,913)	88,467,964	$51,775,874
11	October	End	2024	5,014,494	(40,003,644)	(1,662,714)	88,086,089	$51,434,224
12	November	End	2024	4,406,185	(39,376,165)	(1,678,516)	87,704,214	$51,055,718
13	December	End	2024	3,798,007	(38,748,686)	(1,694,318)	87,322,339	$50,677,342
14	Total			$74,381,169	($552,676,285)	($20,793,585)	$1,164,976,657	$665,887,955
15								
16	Simple Average - total utility			$3,686,905	($42,513,560)	($1,599,505)	$89,613,589	$49,187,428
17								
18								
19	**NORTH DAKOTA JURISDICTION**					**Test Year 2024**		
20		**Allocator**		**ND Percent**				**ND Dollars**
21	Prepayments	NEPIS		37.83%				$18,607,498

DETAILED RATE BASE COMPONENTS
CUSTOMER ADVANCES AND DEPOSITS

Line No.				**Test Year 2024 Customer Advances**
1	December	End	2023	($1,876,522)
2	January	End	2024	($1,876,522)
3	February	End	2024	($1,876,522)
4	March	End	2024	($1,876,522)
5	April	End	2024	($1,876,522)
6	May	End	2024	($1,876,522)
7	June	End	2024	($1,876,522)
8	July	End	2024	($1,876,522)
9	August	End	2024	($1,876,522)
10	September	End	2024	($1,876,522)
11	October	End	2024	($1,876,522)
12	November	End	2024	($1,876,522)
13	December	End	2024	($1,876,522)
14	Total			(24,394,786)
15	Average advances - Simple Average - total utility			($1,876,522)
1	Total to allocate			($1,876,522)
2				
3	**NORTH DAKOTA JURISDICTION**			
4				

5		**Test Year 2024**	
6	**Allocator**	**ND Percent**	**ND Dollars**
7	NEPIS	37.830%	($709,884)

Line No.	Item	Most Recent Actual Year 2022 Total Utility	Most Recent Actual Year 2022 North Dakota	Current Period 2023 Total Utility	Current Period 2023 North Dakota	Test Year 2024 Total Utility	Test Year 2024 North Dakota
1	Cash Working Capital Calculation - Revenue Lead Days						
2							
3	Revenues						
4	Computer Maintained Billings	$401,174,736	$167,046,573	$408,279,090	$173,890,333	$402,362,096	$160,480,581
5	Manually Maintained Billings	56,001,536	23,318,679	56,993,045	24,273,934	72,334,225	28,850,229
6	Cost of Energy Adjustment Revenues	6,772,050	(3,352,822)	6,772,050	(3,352,822)	(8,886,328)	(6,094,976)
7	Sales for Resale	15,789,788	6,455,720	7,164,607	3,077,396	6,943,840	3,125,191
8	Rent from Electric Property	758,797	267,685	939,659	347,284	435,931	164,912
9	Miscellaneous	3,836,962	1,824,627	2,094,605	774,134	1,395,880	528,058
10	ITA Deficiency Payments	920,934	324,884	841,253	310,914	848,757	321,083
11	Wheeling	432,245	0	420,973	0	425,279	0
12	Load Control and Dispatch	21,258,411	8,748,452	51,390,854	8,200,999	51,559,870	7,661,436
13	Rent from Electric Property - Big Stone	182,613	64,422	0	0	0	0
14	Rent from Electric Property - Coyote	3,759	1,326	0	0	0	0
15	Profit on Materials and Supplies	0	0	0	0	0	0
16	Rubber Goods Testing	22,552	7,956	0	0	0	0
17	Residential Conservation Services	0	0	0	0	0	0
18							
19	**Total Revenues**	$507,154,384	$204,707,501	$534,896,136	$207,522,172	$527,419,550	$195,036,514
20							
21	Revenue Lead Days from Service to Collection						
22	Computer Maintained Billings	N/A	38.6	N/A	38.6	N/A	39.8
23	Manually Maintained Billings	N/A	41.7	N/A	41.7	N/A	26.7
24	Cost of Energy Adjustment Revenues	N/A	127.0	N/A	127.0	N/A	126.8
25	Sales for Resale	N/A	20.7	N/A	20.7	N/A	19.9
26	Rent from Electric Property	N/A	(71.1)	N/A	(71.1)	N/A	(63.3)
27	Miscellaneous	N/A	36.6	N/A	36.6	N/A	40.4
28	ITA Deficiency Payments	N/A	16.6	N/A	16.6	N/A	27.5
29	Wheeling	N/A	36.6	N/A	36.6	N/A	39.3
30	Load Control and Dispatch	N/A	29.4	N/A	29.4	N/A	28.8
31	Rent from Electric Property - Big Stone	N/A	36.3	N/A	-	N/A	34.3
32	Rent from Electric Property - Coyote	N/A	36.3	N/A	-	N/A	34.3
33	Profit on Materials and Supplies	N/A	36.3	N/A	-	N/A	34.3
34	Rubber Goods Testing	N/A	36.3	N/A	-	N/A	34.3
35	Residential Conservation Services	N/A	36.3	N/A	-	N/A	34.3
36							
37	Revenue Dollar Days (Revenues X Revenue Lead Days)						
38	Computer Maintained Billings	$15,470,889,369	$6,441,978,586	$15,744,861,451	$6,705,901,106	$16,014,011,424	$6,387,127,127
39	Manually Maintained Billings	2,335,264,067	972,388,901	2,376,609,971	1,012,223,034	1,931,323,820	770,301,109
40	Cost of Energy Adjustment Revenues	(35,049,803)	(425,869,862)	561,024,703	(425,137,830)	(1,044,720,642)	(772,842,957)
41	Sales for Resale	327,350,503	133,838,612	148,535,090	63,799,925	137,835,216	62,035,035
42	Rent from Electric Property	(53,922,433)	(19,022,545)	(66,775,056)	(24,679,038)	(27,581,376)	(10,433,975)
43	Miscellaneous	140,279,345	66,708,350	75,711,463	27,981,797	56,337,728	21,312,441
44	ITA Deficiency Payments	15,250,667	5,380,071	13,931,145	5,148,738	23,340,818	8,829,781
45	Wheeling	15,811,533	0	15,399,187	0	16,700,704	0
46	Load Control and Dispatch	624,988,671	257,200,929	1,510,870,259	241,106,054	1,484,924,256	220,649,367
47	Rent from Electric Property - Big Stone	6,425,680	2,338,501	144	37	0	0
48	Rent from Electric Property - Coyote	132,279	48,140	144	37	0	0
49	Profit on Materials and Supplies	0	0	144	37	0	0
50	Rubber Goods Testing	793,560	288,801	144	37	0	0
51	Residential Conservation Services	0	0	0	0	0	0
52							
53	**Total Dollar Days**	$18,848,213,439	$7,435,278,483	$20,380,168,789	$7,606,343,933	$18,592,171,948	$6,686,977,928
54							
55	**Avg Revenue Lead Days (Total Rev Dollar Days / Total Rev)**	37.2	**36.3**	38.1	**36.7**	35.3	**34.3**
56							
57	**Calculation of Days from Service to Collection**						
58	Service Period to Date Meter is Read	(365 / 12 / 2)	15.3	(365 / 12 / 2)	15.3	(365 / 12 / 2)	15.3
59	Read Date to Date Billing is Prepared		5.1		5.1		5.1
60	Billing Date to Date collection is Received		19.5		19.5		19.5
61	Total		39.9		39.9		39.9

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
CASH WORKING CAPITAL
Calculation applying lead-lag factors

Case No. PU-23-342
Supplemetal Exhibit ___ (CLP-1), Schedule B-2-e

		Most Recent Actual Year 2022						Current Period 2023					
		NORTH DAKOTA JURISDICTION					TOTAL UTILITY	NORTH DAKOTA JURISDICTION					TOTAL UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Item	Operating Expense	Expense/day at 365 day/year	Expense Lag Days	Lead Days of 36.3 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars	Operating Expense	Expense/day at 366 day/year	Expense Lag Days	Lead Days of 36.7 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	Fuel - Coal			20.4	15.9			$17,936,135	$49,140	20.4	16.3	800,255	$2,051,463
2	Fuel - Oil			10.2	26.1			$4,830,611	$13,235	10.0	26.0	350,583	$891,261
3	Purchased Power	$41,519,723	$113,753	27.1	9.2	1,437,996	$2,755,829	$40,147,133	$109,992	27.1	9.6	1,051,525	$2,898,277
4	Labor and Associated Payroll Expense	$27,441,856	$75,183	11.1	25.2	2,657,758	$5,081,952	$28,167,213	$77,170	11.1	25.6	1,977,107	$5,110,153
5	All Other O&M Expense	$61,696,034	$169,030	19.1	17.2	4,040,147	$7,726,271	$37,093,105	$101,625	19.1	17.6	1,789,615	$5,375,046
6	Property Taxes (Excl Coal Conversion Taxes)	$6,425,604	$17,604	252.2	(215.9)	(4,475,450)	($9,199,471)	$6,399,137	$17,532	229.0	(260.2)	(4,561,443)	($12,256,884)
7	Coal Conversion Taxes	$38,411	$105	27.9	8.4	1,240	$2,376	$38,251	$105	28.0	8.8	926	$2,705
8	Federal Income Taxes				36.3						36.7		
9	State Income Taxes				36.3						36.7		
10	Incremental Federal Income Taxes				36.3						36.7		
11	Incremental State Income Taxes				36.3						36.7		
12	Bank Balances					962	$2,300					850	$2,300
13	Special Deposits					631,593	$1,509,911					558,040	$1,509,911
14	Working Funds					5,069	$12,118					4,479	$12,118
15	Tax Collections Available												
16	FICA Withholding	($2,209,297)	($6,053)					($2,384,754)	($6,534)				
17	Federal Withholding	($3,571,267)	($9,784)					($3,854,889)	($10,561)				
18	State Withholding- MN			2.1		(10,914)	(10,914)						
19	State Withholding- ND	($303,808)	($832)	65.0			(54,078)	($303,808)	($832)	61.0		(50,965)	($63,825)
20	State Sales Tax	($72)		15.2		(541,999)	(641,797)	($72)		14.0		(3)	($486,516)
21	Franchise Taxes					96,773	96,773			37.0			($30,458)
22													
23	**Total Cash Working Capital Requirement**					**3,843,176**	**$7,281,269**					**1,920,969**	**$5,015,551**

CASH WORKING CAPITAL
Calculation applying lead-lag factors

		Test Year 2024					
		NORTH DAKOTA JURISDICTION					TOTAL UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Item	Operating Expense	Expense/day at 365 day/year	Expense Lag Days	Lead Days of 34.3 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	Fuel - Coal	$23,301,382	$63,839	19.1	15.2	$969,721	2,334,802
2	Fuel - Oil	$4,561,691	$12,498	8.9	25.4	$317,569	760,460
3	Purchased Power	$42,027,450	$115,144	32.8	1.5	$176,170	714,928
4	Labor and Associated Payroll Expense	$29,064,971	$79,630	10.5	23.8	$1,896,788	4,782,925
5	All Other O&M Expense	$41,312,276	$113,184	12.5	21.8	$2,468,550	6,915,466
6	Property Taxes (Excl Coal Conversion Taxes)	$7,062,227	$19,349	296.2	(261.9)	($5,067,148)	(13,308,942)
7	Coal Conversion Taxes	$41,286	$113	35.6	(1.3)	($146)	(232)
8	Federal Income Taxes				34.3		
9	State Income Taxes				34.3		
10	Incremental Federal Income Taxes				34.3		
11	Incremental State Income Taxes				34.3		
12	Bank Balances						
13	Special Deposits					$816,531	2,158,433
14	Working Funds					$4,734	12,513
15	Tax Collections Available						
16	FICA Withholding	($2,399,760)	($6,575)				
17	Federal Withholding	($3,879,146)	($10,628)				
18	State Withholding- MN						
19	State Withholding- ND	($303,808)	($832)	61.2		($50,965)	(63,825)
20	State Sales Tax	($72)		13.8		($3)	(486,516)
21	Franchise Taxes						(30,458)
22							
23	**Total Cash Working Capital Requirement**					**1,531,800**	**3,789,554**

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE Page 2 of 2
RATE BASE ADJUSTMENTS
Unadjusted Year 2024 to Regulatory Year 2024

Case No. PU-23-342
Supplemental Exhibit ___ (CLP-1), Schedule B-3

			Adjustments					
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Description	Unadjusted Year 2024	GIPs Projects	Hoot Lake Solar	Transmission Recovery	Electric Vehicles	Changes in Allocations Due to Effect of Test Year Adjustments	Regulatory Year 2024
	Utility Plant in Service:							
1	Production	$658,582,109		($26,462,276)				$632,119,833
2	Transmission	$323,246,976	($19,287,409)		($88,138,714)			$215,820,853
3	Distribution	$330,597,673				(846,512)	$1	$329,751,162
4	General	$53,300,696						$53,300,696
5	Intangible	$18,266,991						$18,266,991
6	**TOTAL Utility Plant in Service**	$1,383,994,445	($19,287,409)	($26,462,276)	($88,138,714)	($846,512)	$1	$1,249,259,535
	Accumulated Depreciation							
7	Production	($246,215,224)		$568,838				($245,646,386)
8	Transmission	($72,478,191)	$1,212,465		$8,657,099			($62,608,627)
9	Distribution	($123,426,235)				42,659		($123,383,576)
10	General	($21,909,007)						($21,909,007)
11	Intangible	($7,538,176)						($7,538,176)
12	**TOTAL Accumulated Depreciation**	($471,566,833)	$1,212,465	$568,838	$8,657,099	$42,659		($461,085,772)
13	**NET Utility Plant in Service**							
14	Production	$412,366,885		($25,893,438)				$386,473,447
15	Transmission	250,768,785	(18,074,944)		($79,481,615)			153,212,226
16	Distribution	207,171,438				(803,853)	$1	206,367,586
17	General	31,391,689						31,391,689
18	Intangible	10,728,815						10,728,815
19	**NET Utility Plant in Service**	$912,427,612	($18,074,944)	($25,893,438)	($79,481,615)	($803,853)	$1	$788,173,763
20	Utility Plant Held for Future Use	4,921						4,921
21	Construction Work in Progress	780,990						780,990
22	Materials and Supplies	14,737,248						14,737,248
23	Fuel Stocks	4,495,117						4,495,117
24	Prepayments	18,601,559						18,601,559
25	Customer Advances & Deposits	(709,657)						(709,657)
26	Cash Working Capital	1,304,936						1,304,936
27	Accumulated Deferred Income Taxes	(187,351,323)	1,425,013	2,633,993	7,549,696			($175,742,621)
28	**Total Average Rate Base**	$764,291,403	($16,649,931)	($23,259,445)	($71,931,919)	($803,853)	$1	$651,646,256

			Adjustments						
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Petersen	**Petersen**	**Petersen**	**Petersen**		
Line No.	Description	Regulatory Year 2024	Normalize Langdon Upgrade Project	Remove ARO Plant Balance	Adjust ADIT Data Request PSC - 201	Revised Langdon Normalizatoin	ITC ADIT NEPIS Allocator	Changes in Allocations Due to Effect of Test Year Adjustments	Test Year 2024
	Utility Plant in Service:								
1	Production	$632,119,833	$2,173,773	($8,423,675)		$517,919		$7,905,756	$634,293,606
2	Transmission	215,820,853						(0)	$215,820,853
3	Distribution	329,751,162						(0)	$329,751,162
4	General	53,300,696						876	$53,301,572
5	Intangible	18,266,991						300	$18,267,291
6	**TOTAL Utility Plant in Service**	$1,249,259,535	$2,173,773	($8,423,675)		$517,919		$7,906,931	$1,251,434,483
	Accumulated Depreciation								
7	Production	($245,646,386)	($304,040)			($148,326)		$148,326	($245,950,426)
8	Transmission	(62,608,627)						1	($62,608,627)
9	Distribution	(123,383,576)						(0)	($123,383,576)
10	General	(21,909,007)						(360)	($21,909,367)
11	Intangible	(7,538,176)						(124)	($7,538,300)
12	**TOTAL Accumulated Depreciation**	($461,085,772)	($304,040)			($148,326)		$147,842	($461,390,296)
13	**NET Utility Plant in Service**								
14	Production	$386,473,447	$1,869,733	($8,423,675)		$369,593		$8,054,082	$388,343,180
15	Transmission	153,212,226						0	153,212,226
16	Distribution	206,367,586						(0)	206,367,586
17	General	31,391,689						515	31,392,204
18	Intangible	10,728,815						176	10,728,991
19	**NET Utility Plant in Service**	$788,173,763	$1,869,733	($8,423,675)		$369,593		$8,054,773	$790,044,187
20	Utility Plant Held for Future Use	$4,921							$4,921
21	Construction Work in Progress	780,990						3	$780,993
22	Materials and Supplies	14,737,248						181	$14,737,429
23	Fuel Stocks	4,495,117							$4,495,117
24	Prepayments	18,601,559						5,939	$18,607,498
25	Customer Advances & Deposits	(709,657)						(227)	($709,884)
26	Cash Working Capital	1,304,936						226,864	$1,531,800
27	Accumulated Deferred Income Taxes	(175,742,621)						41,675,379	($134,067,242)
28	**Total Average Rate Base**	$651,646,256	$1,869,733	($8,423,675)		$369,593		$49,962,912	$695,424,818

SUMMARY OF APPROACHES AND ASSUMPTIONS USED IN DETERMINING AVERAGE RATE BASE FOR PROPOSED TEST YEAR 2024

The 2024 Proposed Test Year is based on Otter Tails's 2024 budget prepared during second quarter 2023.

A simple average of beginning and end of year balances is used for all rate base components.

The allocation factors on this page were used to determine Minnesota jurisdictional rate base amounts for all of the years presented in these schedules. Accounts not on this page have been directly assigned to jurisdictions.

Descriptions under the Allocation Factor column with a / means the first method was used in historic actual and projected, the method after the / is used in the test year.

The following allocation factors are used to compute Minnesota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress.

For a full description of each allocation factor, see OTP's *Cost Allocation Procedure Manual for Jurisdictional and Class Cost of Service Studies* , Stuart Tommerdahl's testimony, Exhibit ___(SDT-1), Schedules 10 and 11.

Line No.	Description	Allocation Basis
	RATE BASE COMPONENT	ALLOCATION FACTOR
1	Electric Plant in Service	
2	Production Plant	
3	Base Demand	kWh Sales Factor (E1)
4	Peak Demand	Generation Demand Factor (D1)
5	Base Energy	kWh Sales Factor (E2)
6	Transmission Plant	Direct Assignment/Transmission Demand Factor (D2)
7	Distribution Plant	
8	Primary Demand	Distribution Primary Demand Factor (D3)
9	Secondary Demand	Distribution Secondary Demand Factor (D4)
10	Primary Customer	Total Retail Service Locations Factor (C2)
11	Secondary Customer	Total Secondary Retail Service Location Factor (C3)
12	Street Lighting	Streetlight Factor (C4)
13	Area Lighting	Area Light Factor (C5)
14	Meters	Meter Factor (C6)
15	Load Management	Load Management Factor (C9)
17	General Plant	
18	Production	Gross Production Plant in Service Ratio (P10)
19	Transmission	Gross Transmission Plant in Service Ratio (D2)
20	Distribution	Gross Distribution Plant in Service Ratio (P60)
21	Customer Accounts	Customer Accounts Expense Ratio (OXC)
22	Customer Service & Info.	Customer Service & Info, Expense Ratio (OXI)
23	Load Management	Load Management Factor (C9)
24	Intangible Plant	Gross General Plant in Service Ratio (P90)
25	Accumulated Provision for Depreciation	
26	Production Plant	
27	Base Demand	kWh Sales Factor (E1)
28	Peak Demand	Generation Demand Factor (D1)
29	Base Energy	kWh Sales Factor (E2)
30	Transmission Plant	Direct Assignment/Transmission Demand Factor (D2)
31	Distribution Plant	Gross Distribution Plant in Service Ratio (P60)
32	General Plant	Gross General Plant in Service Ratio (P90)
33	Intangible Plant	Gross General Plant in Service Ratio (P90)

SUMMARY OF RATE BASE JURISDICTIONAL ALLOCATION FACTORS

Line No.	RATE BASE COMPONENT	ALLOCATION FACTOR
1	Electric Plant Held for Future Use	
2	Production Plant	Gross Production Plant in Service Ratio (P10)
3	Transmission Plant	Transmission Demand Factor (D2)
4	Distribution Plant	Gross Distribution Plant in Service Ratio (P60)
5	General Plant	Gross General Plant in Service Ratio (P90)
6	Intangible Plant	Gross General Plant in Service Ratio (P90)
7	Construction Work in Progress — Short Term	
8	Production Plant	Gross Production Plant in Service Ratio (P10)
9	Transmission Plant	Direct Assignment/Transmission Demand Factor (D2)
10	Distribution Plant	Gross Distribution Plant in Service Ratio (P60)
11	General Plant	Gross General Plant in Service Ratio (P90)
12	Intangible Plant	Gross General Plant in Service Ratio (P90)
13	Construction Work in Progress — Long Term	
14	Production Plant	Gross Production Plant in Service Ratio (P10)
15	Transmission Plant	Transmission Demand Factor (D2)
16	Distribution Plant	Gross Distribution Plant in Service Ratio (P60)
17	General Plant	Gross General Plant in Service Ratio (P90)
18	Intangible Plant	Gross General Plant in Service Ratio (P90)
19	Materials and Supplies	
20	Production	Gross Production Plant in Service Ratio (P10)
21	Transmission	Transmission Demand Factor (D2)
22	Distribution	Gross Distribution Plant in Service Ratio (P60)
23	Fuel Stocks	
24	Coal Stocks	kWh Sales Factor (E1)
25	Fuel Oil Stocks	Generation Demand Factor (D1)
26	Prepayments	Total Net Plant in Service Ratio (NEPIS)
27	Customer Advances	Total Net Plant in Service Ratio (NEPIS)
28	Cash Working Capital	Separately Calculated by Jurisdiction
29	Accumulated Deferred Income Taxes	
30	Items South Dakota flows through:	
31	Federal	Total Net Plant in Service Ratio (NPMNR)
32	Minnesota	Total Net Plant in Service — MN Ratio (NPISM)
33	North Dakota	Total Net Plant in Service — ND Ratio (NPISN)
34	All Other:	
35	Federal	Total Net Plant in Service Except Direct Assignment Ratio (NEPIS EXDA)
36	Federal	Direct Assignment
37	Minnesota	Total Net Plant in Service — MN Ratio (NPISM)
38	North Dakota	Total Net Plant in Service — ND Ratio (NPISN)

Allocators - Demand, Energy and Customer

			Most Recent Actual Year 2022			Current Period 2023		
Line No.	**Item**	**Factor**	**Total Utility**	**North Dakota**	**All Other**	**Total Utility**	**North Dakota**	**All Other**
1	MWH Consumption at Generators - Partial	E1	5,477,199	2,176,780	3,300,419	5,828,855	2,463,270	3,365,585
2	Percentage		100.000000%	39.742576%	60.257424%	100.000000%	42.259929%	57.740071%
3	MWH Consumption at Generators - Total	E2	6,047,550	2,506,064	3,541,486	6,388,235	2,786,350	3,601,885
4	Percentage		100.000000%	41.439327%	58.560673%	100.000000%	43.616899%	56.383101%
5	Generation Demand Factor	D1	744,816	288,255	456,561	732,267	292,412	439,855
6	Percentage		100.000000%	38.701505%	61.298495%	100.000000%	39.932429%	60.067571%
7	Transmission Demand Factor	D2	749,267	288,255	461,012	737,663	292,412	445,251
8	Percentage		100.000000%	38.471600%	61.528400%	100.000000%	39.640324%	60.359676%
9	Distribution - Primary Demand Factor	D3	855,471	390,364	465,107	849,891	389,743	460,148
10	Percentage		100.000000%	45.631471%	54.368529%	100.000000%	45.857998%	54.142002%
11	Distribution - Secondary Demand Factor	D4	1,059,385	510,894	548,491	1,103,719	518,815	584,904
12	Percentage		100.000000%	48.225527%	51.774473%	100.000000%	47.006077%	52.993923%
13	Customer or Meter Factors							
14	Total Retail Customers	C1	134,621	59,558	75,063	135,015	59,600	75,415
15	Percentage		100.000000%	44.241240%	55.758760%	100.000000%	44.143243%	55.856757%
16	Retail Service Locations	C2	135,654	59,558	76,096	136,049	59,600	76,449
17	Percentage		100.000000%	43.904345%	56.095655%	100.000000%	43.807746%	56.192254%
18	Secondary Service Locations	C3	135,615	59,548	76,067	136,014	59,590	76,424
19	Percentage		100.000000%	43.909597%	56.090403%	100.000000%	43.811666%	56.188334%
20	Street Lighting Factor	C4	13,235,267	5,515,574	7,719,693	13,235,267	5,515,574	7,719,693
21	Percentage		100.000000%	41.673311%	58.326689%	100.000000%	41.673311%	58.326689%
22	Area Lighting Factor	C5	9,628,628	5,249,227	4,379,401	9,628,628	5,249,227	4,379,401
23	Percentage		100.000000%	54.516874%	45.483126%	100.000000%	54.516874%	45.483126%
24	Meter Factor	C6	57,578,353	25,668,459	31,909,894	57,578,353	25,668,459	31,909,894
25	Percentage		100.000000%	44.580051%	55.419949%	100.000000%	44.580051%	55.419949%
26	Meter Reading Factor	C7	205,116	90,998	114,118	205,638	91,075	114,563
27	Percentage		100.000000%	44.364165%	55.635835%	100.000000%	44.288993%	55.711007%
28	System Service Locations	C8	135,662	59,559	76,103	136,057	59,601	76,456
29	Percentage		100.000000%	43.902493%	56.097507%	100.000000%	43.805905%	56.194095%
30	Load Management Factor	C9	41,948	18,352	23,596	41,706	18,234	23,472
31	Percentage		100.000000%	43.749404%	56.250596%	100.000000%	43.720328%	56.279672%

Allocators - Demand, Energy and Customer

Line No.	Item	Factor	Proposed Test Year 2024 Total Utility	North Dakota	All Other
1	MWH Consumption at Generators - Partial	E1	5,645,126	2,476,736	3,168,390
2	Percentage		100.000000%	43.873883%	56.126117%
3	MWH Consumption at Generators - Total	E2	6,171,457	2,775,986	3,395,471
4	Percentage		100.000000%	44.981047%	55.018953%
5	Generation Demand Factor	D1	719,976	284,282	435,694
6	Percentage		100.000000%	39.484927%	60.515073%
7	Transmission Demand Factor	D2	725,298	284,282	441,016
8	Percentage		100.000000%	39.195200%	60.804800%
9	Distribution - Primary Demand Factor	D3	851,393	396,080	455,313
10	Percentage		100.000000%	46.521407%	53.478593%
11	Distribution - Secondary Demand Factor	D4	1,119,241	545,068	574,173
12	Percentage		100.000000%	48.699789%	51.300211%
13	Customer or Meter Factors				
14	Total Retail Customers	C1	135,411	59,643	75,768
15	Percentage		100.000000%	44.045905%	55.954095%
16	Retail Service Locations	C2	136,449	59,642	76,807
17	Percentage		100.000000%	43.710104%	56.289896%
18	Secondary Service Locations	C3	136,414	59,632	76,782
19	Percentage		100.000000%	43.713988%	56.286012%
20	Street Lighting Factor	C4	13,235,267	5,515,574	7,719,693
21	Percentage		100.000000%	41.673311%	58.326689%
22	Area Lighting Factor	C5	9,628,628	5,249,227	4,379,401
23	Percentage		100.000000%	54.516874%	45.483126%
24	Meter Factor	C6	57,578,353	25,668,459	31,909,894
25	Percentage		100.000000%	44.580051%	55.419949%
26	Meter Reading Factor	C7	206,170	91,157	115,013
27	Percentage		100.000000%	44.214483%	55.785517%
28	System Service Locations	C8	136,457	59,643	76,814
29	Percentage		100.000000%	43.708274%	56.291726%
30	Load Management Factor	C9	41,469	18,119	23,350
31	Percentage		100.000000%	43.692879%	56.307121%

Allocators - General Plant, Operation and Maintenance Expense and Taxes

			Most Recent Actual Year 2022			Current Period 2023		
Line No.	Item	Factor	Total Utility	North Dakota	All Other	Total Utility	North Dakota	All Other
1	Production Plant	P10	1,336,122,578	535,749,544	800,373,034	1,396,605,647	586,915,725	809,689,922
2	Percentage		100.000000%	40.097335%	59.902665%	100.000000%	42.024442%	57.975558%
3	Distribution Plant	P60	594,253,855	271,503,168	322,750,687	650,211,687	295,374,578	354,837,109
4	Percentage		100.000000%	45.688078%	54.311922%	100.000000%	45.427448%	54.572552%
5	General Plant	P90	106,022,339	44,822,076	61,200,262	113,108,289	48,655,555	64,452,734
6	Percentage		100.000000%	42.276068%	57.723932%	100.000000%	43.016790%	56.983210%
7	Electric Plant in Service	EPIS	2,808,691,578	1,041,850,025	1,766,841,553	2,979,345,803	1,148,337,185	1,831,008,618
8	Percentage		100.000000%	37.093785%	62.906215%	100.000000%	38.543266%	61.456734%
9	Net Electric Plant in Service	NEPIS	1,844,282,690	650,618,846	1,193,663,844	1,955,239,414	722,626,540	1,232,612,874
10	Percentage		100.000000%	35.277610%	64.722390%	100.000000%	36.958468%	63.041532%
11	Net Electric Plant in Service Excluding Direct Assignment	NEPISEXDA	1,580,979,545	650,618,846	930,360,699	1,707,469,254	722,626,540	984,842,714
12	Percentage		100.000000%	41.152895%	58.847105%	100.000000%	51.030000%	48.970000%
13	Operation and Maintenance Expense							
14	Production Expense (Excl Energy)	OXPD	22,808,745	9,002,304	13,806,441	22,830,396	9,473,734	13,356,662
15	Percentage		100.000000%	39.468650%	60.531350%	100.000000%	41.496145%	58.503855%
16	Distribution Expense	OXD	17,303,680	7,838,847	9,464,834	16,933,996	7,648,887	9,285,109
17	Percentage		100.000000%	45.301615%	54.698385%	100.000000%	45.168824%	54.831176%
18	Customer Accounts Expense	OXC	14,027,785	6,186,536	7,841,249	15,247,193	6,709,753	8,537,440
19	Percentage		100.000000%	44.102016%	55.897984%	100.000000%	44.006480%	55.993520%
20	Customer Service & Information Expense	OXI	2,640,694	1,168,276	1,472,418	2,799,489	1,235,785	1,563,704
21	Percentage		100.000000%	44.241240%	55.758760%	100.000000%	44.143239%	55.856761%
22	Other Deferred Income Tax Factor							
23	Minnesota	NPISM	1,038,294,699	0	1,038,294,699	569,482,680	0	569,482,680
24	Percentage		100.000000%	0.000000%	100.000000%	100.000000%	99.540561%	0.459439%
25	North Dakota	NPISN	650,618,846	650,618,846	0	481,698,161	474,856,379	6,841,782
26	Percentage		100.000000%	100.000000%	0.000000%	100.000000%	98.579654%	1.420346%
27	Excluding South Dakota	NPMNR	1,688,913,545	650,618,846	1,038,294,699	1,787,649,542	722,626,540	1,065,023,002
28	Percentage		100.000000%	38.522922%	61.477078%	100.000000%	40.423278%	59.576722%
29	Long-Term CWIP Ratio (W/AFDC)	CWIPLT	78,640,439	0	78,640,439	0	0	0
30	Percentage		100.000000%	0.000000%	100.000000%	0.000000%	0.000000%	0.000000%
31	Revenue	R10	462,806,067	186,549,483	276,256,584	0	0	0
32	Percentage		100.000000%	40.308349%	59.691651%	0.000000%	0.000000%	0.000000%
33	Labor and Related Expense	LRE	152,936,981	58,665,955	94,271,026	143,469,859	59,405,107	84,064,752
34	Percentage		100.000000%	38.359561%	61.640439%	100.000000%	41.405984%	58.594016%

Allocators - General Plant, Operation and Maintenance Expense and Taxes

Line No.	Item	Factor	Proposed Test Year 2024 Total Utility	North Dakota	All Other
1	Production Plant	P10	1,474,611,883	634,293,606	840,318,278
2	Percentage		100.000000%	43.014275%	56.985725%
3	Distribution Plant	P60	717,695,528	329,751,161	387,944,367
4	Percentage		100.000000%	45.945829%	54.054171%
5	General Plant	P90	122,942,613	53,301,572	69,641,041
6	Percentage		100.000000%	43.354839%	56.645161%
7	Electric Plant in Service	EPIS	3,182,095,019	1,251,434,481	1,930,660,538
8	Percentage		100.000000%	39.327376%	60.672624%
9	Net Electric Plant in Service	NEPIS	2,088,418,443	790,044,183	1,298,374,259
10	Percentage		100.000000%	37.829784%	62.170216%
11	Net Electric Plant in Service Excluding Direct Assignment	NEPISEXDA	1,841,633,693	790,044,183	1,051,589,509
12	Percentage		100.000000%	42.899095%	57.100905%
13	Operation and Maintenance Expense				
14	Production Expense (Excl Energy)	OXPD	26,965,239	11,444,690	15,520,549
15	Percentage		100.000000%	42.442381%	57.557619%
16	Distribution Expense	OXD	18,488,356	8,393,231	10,095,125
17	Percentage		100.000000%	45.397391%	54.602609%
18	Customer Accounts Expense	OXC	16,621,213	7,295,595	9,325,619
19	Percentage		100.000000%	43.893273%	56.106727%
20	Customer Service & Information Expense	OXI	3,021,886	1,331,017	1,690,869
21	Percentage		100.000000%	44.045905%	55.954095%
22	Other Deferred Income Tax Factor				
23	Minnesota	NPISM	921,398,315	0	921,398,315
24	Percentage		100.000000%	0.000000%	100.000000%
25	North Dakota	NPISN	1,044,150,583	790,044,183	254,106,399
26	Percentage		100.000000%	98.686980%	1.313020%
27	Excluding South Dakota	NPMNR	1,905,077,361	790,044,183	1,115,033,178
28	Percentage		100.000000%	41.470452%	58.529548%
29	Long-Term CWIP Ratio (W/AFDC)	CWIPLT	0	0	0
30	Percentage		0.000000%	0.000000%	0.000000%
31	Revenue	R10	464,659,581	182,782,835	281,876,746
32	Percentage		100.000000%	39.336934%	60.663066%
33	Labor and Related Expense	LRE	151,972,523	63,326,540	88,645,983
34	Percentage		100.000000%	41.669730%	58.330270%

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C. Operating Income Schedules

OPERATING INCOME SCHEDULES.

The following operating income schedules are included in this filing:

A. A summary schedule of jurisdictional operating income statements which reflect the Most Recent Actual Year, the projected Current Year, the Unadjusted Year which is the projected fiscal year, the Regulatory Year which is the projected fiscal year based on most recent Commission approvals calculated using present rates, and the proposed Test Year.

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

C. A summary schedule showing the computation of total utility and allocated North Dakota jurisdictional federal and state income tax expense and deferred income taxes for the test year, the most recent fiscal year, and the projected fiscal year. This summary schedule shall be supported by a detailed schedule, showing the development of the combined federal and state income tax rates.

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

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

F. A schedule providing, by operating income element, the factor or factors used in allocating total utility operating income to the North Dakota jurisdiction. This schedule is supported by a schedule which sets forth the statistics used in determining each jurisdictional allocation factor for the test year, the most recent fiscal year, and the projected fiscal year.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME SCHEDULES
JURISDICTIONAL STATEMENT OF OPERATING INCOME

Line No.	Description	(A) Most Recent Actual Year 2022	(B) Current Period 2023	(C) Unadjusted Year 2024	(D) Regulatory Year 2024	(E) Test Year 2024
	OPERATING REVENUES					
1	Retail Revenue	$186,549,483	$194,336,780	$203,210,040	$205,989,209	$182,782,835
2	Other Electric Operating Revenue	18,158,019	13,185,392	26,709,463	12,976,906	12,253,679
3	**TOTAL OPERATING REVENUE**	$204,707,501	$207,522,172	$229,919,503	$218,966,115	$195,036,514
	OPERATING EXPENSES					
4	Production Expenses	$80,952,165	$78,192,135	$85,426,089	$86,694,044	$88,254,903
5	Transmission Expenses	14,387,811	14,184,319	13,847,298	13,847,298	$14,086,555
6	Distribution Expenses	7,838,847	7,648,887	7,972,703	7,972,703	8,393,231
7	Customer Accounting Expenses	6,186,536	6,709,753	7,035,433	7,035,433	7,295,595
8	Customer Service and Information Expenses	1,168,276	1,235,785	1,315,049	1,315,049	1,331,017
9	Sales Expenses	41,797	50,689	142,408	135,872	135,872
10	Administration and General Expenses	20,082,182	20,152,628	20,022,371	17,534,200	20,770,596
11	Charitable Contributions	0	0	0	0	0
12	Depreciation Expense	26,709,167	29,426,229	35,004,108	32,603,918	33,165,285
13	General Taxes	6,464,014	6,437,388	8,019,087	7,102,692	7,103,512
14	**TOTAL OPERATING EXPENSES**	$163,830,794	$164,037,814	$178,784,546	$174,241,209	$180,536,566
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$40,876,707	$43,484,358	$51,134,957	$44,724,906	$14,499,948
16	**INCOME TAX EXPENSE**					
17	Investment Tax Credit	($2,295,960)	($2,405,524)	($8,230,037)	($2,939,568)	($2,939,618)
18	Deferred Income Taxes	7,985,656	7,106,564	5,059,807	5,059,809	(2,550,314)
19	Income Taxes	0			0	(0)
20	**TOTAL INCOME TAX EXPENSE**	$5,689,696	$4,701,040	($3,170,229)	$2,120,241	($5,489,932)
21	**NET OPERATING INCOME**	$35,187,011	$38,783,318	$54,305,185	$42,604,666	$19,989,880
22	Allowance for Funds Used During Construction	0	0	0	0	0
23	**TOTAL AVAILABLE FOR RETURN**	$35,187,011	$38,783,318	$54,305,185	$42,604,666	$19,989,880

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME

Case No. PU-23-
Exhibit__(CLP-1), Schedule C-2

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		Most Recent Actual Year 2022		Current Period 2023		Unadjusted Year 2024		Regulatory Year 2024		Test Year 2024	
Line No.	Description	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction
	OPERATING REVENUES										
1	Retail Revenue	$462,806,067	$186,549,483	$470,818,004	$194,336,780	$485,086,787	$203,210,040	$487,865,956	$205,989,209	$464,659,582	$182,782,835
2	Other Electric Operating Revenue	74,907,477	18,158,019	64,082,146	13,185,392	62,763,923	$26,709,463	62,763,924	12,976,906	62,763,924	12,253,679
3	**TOTAL OPERATING REVENUE**	$537,713,544	$204,707,501	$534,900,150	$207,522,172	$547,850,710	$229,919,503	$550,629,880	$218,966,115	$527,423,506	$195,036,514
	OPERATING EXPENSES										
4	Production Expenses	$197,795,331	$80,952,165	$181,595,934	$78,192,135	$193,038,667	$85,426,089	$195,857,531	$86,694,044	$199,374,085	$88,254,903
5	Transmission Expenses	37,477,229	14,387,811	35,782,550	$14,184,319	35,329,066	$13,847,298	35,329,066	$13,847,298	$35,939,490	14,086,555
6	Distribution Expenses	17,303,680	7,838,847	16,933,996	$7,648,887	17,553,489	$7,972,703	17,553,489	$7,972,703	$18,488,356	8,393,231
7	Customer Accounting Expenses	14,027,785	6,186,536	15,247,193	$6,709,753	16,028,499	$7,035,433	16,028,499	$7,035,433	$16,621,213	7,295,595
8	Customer Service and Information Expenses	10,866,633	1,168,276	12,324,489	$1,235,785	12,470,633	$1,315,049	12,470,633	$1,315,049	$12,622,058	1,331,017
9	Sales Expenses	526,191	41,797	883,655	$50,689	590,747	$142,408	583,457	$135,872	$583,457	135,872
10	Administration and General Expenses	50,531,612	20,082,182	49,876,234	$20,152,628	49,655,042	$20,022,371	43,893,859	$17,534,200	$50,936,338	20,770,596
11	Charitable Contributions	0	0	0	$0	0	$0	0	$0	$0	0
12	Depreciation Expense	68,140,836	26,709,167	73,242,770	$29,426,229	81,175,633	$35,004,108	79,405,970	$32,603,918	$80,703,774	33,165,285
13	General Taxes	17,733,835	6,464,014	17,346,958	$6,437,388	18,693,896	$8,019,087	18,693,896	$7,102,692	$18,693,895	7,103,512
14	**TOTAL OPERATING EXPENSES**	$414,403,133	$163,830,794	$403,233,779	$164,037,813	$424,535,672	$178,784,546	$419,816,400	$174,241,209	$433,962,668	$180,536,566
15	**NET OPERATING INCOME BEFORE INCOME TAX**	$123,310,411	$40,876,707	$131,666,371	$43,484,360	$123,315,038	$51,134,957	$130,813,480	$44,724,906	$93,460,838	$14,499,948
16	**INCOME TAX EXPENSE**										
17	Investment Tax Credit	($5,618,608)	($2,295,960)	($5,601,725)	($2,405,524)	($18,479,472)	($8,230,037)	($6,628,472)	($2,939,568)	($6,628,472)	($2,939,618)
18	Deferred Income Taxes	23,632,327	7,985,656	16,294,208	$7,106,564	8,924,177	$5,059,807	17,836,409	$5,059,809	8,207,594	(2,550,314)
19	Income Taxes	(430,020)	0	1,952,449	$0			0	$0	(1,284,272)	0
20	**TOTAL INCOME TAX EXPENSE**	$17,583,699	$5,689,696	$12,644,932	$4,701,040	($9,555,295)	($3,170,229)	$11,207,937	$2,120,241	$294,850	($5,489,932)
21	**NET OPERATING INCOME**	$105,726,712	$35,187,011	$119,021,440	$38,783,318	$132,870,333	$54,305,185	$119,605,543	$42,604,665	$93,165,988	$19,989,880
22	Allowance for Funds Used During Construction	2,620,406	0	0	0	0	0	0	0	6,315,997	0
23	**TOTAL AVAILABLE FOR RETURN**	$108,347,119	$35,187,011	$119,021,440	$38,783,318	$132,870,333	$54,305,185	$119,605,543	$42,604,665	$99,481,985	$19,989,880

STATEMENT OF OPERATING INCOME - REGULATORY YEAR 2024

		(A)	(B)	(C)	(D)
			Regulatory Year 2024		
Line No.	Description	Unadjusted Year 2024 Total Utility	Unadjusted Year 2024 ND Jurisdiction	Adjustments	Regulatory Year 2024 ND Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$485,086,787	$203,210,040	$2,779,169	$205,989,209
2	Other Electric Operating Revenue	62,763,923	26,709,463	(13,732,557)	12,976,906
3	**TOTAL OPERATING REVENUE**	$547,850,710	$229,919,503	($10,953,388)	$218,966,115
	OPERATING EXPENSES				
4	Production Expenses	$193,038,667	$85,426,089	$1,267,955	$86,694,044
5	Transmission Expenses	$35,329,066	$13,847,298	0	$13,847,298
6	Distribution Expenses	$17,553,489	$7,972,703	0	$7,972,703
7	Customer Accounting Expenses	$16,028,499	$7,035,433	0	$7,035,433
8	Customer Service and Information Expenses	$12,470,633	$1,315,049	0	$1,315,049
9	Sales Expenses	$590,747	$142,408	(6,536)	$135,872
10	Administration and General Expenses	$49,655,042	$20,022,371	(2,488,171)	$17,534,200
11	Charitable Contributions	$0	$0	0	$0
12	Depreciation Expense	$81,175,633	$35,004,108	(2,400,190)	$32,603,918
13	General Taxes	$18,693,896	$8,019,087	(916,395)	$7,102,692
14	**TOTAL OPERATING EXPENSES**	$424,535,672	$178,784,546	($4,543,337)	$174,241,209
15	**NET OPERATING INCOME BEFORE INCOME TAX**	$123,315,038	$51,134,957	($6,410,051)	$44,724,906
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($18,479,472)	($8,230,037)	$5,290,469	($2,939,568)
18	Deferred Income Taxes	8,924,177	$5,059,807	2	$5,059,809
19	Income Taxes	0	$0	0	$0
20	**TOTAL INCOME TAX EXPENSE**	($9,555,295)	($3,170,230)	$5,290,471	$2,120,241
21	**NET OPERATING INCOME**	$132,870,333	$54,305,186	($11,700,522)	$42,604,665
22	Allowance for Funds Used During Construction	0	0	0	0
23	**TOTAL AVAILABLE FOR RETURN**	$132,870,333	$54,305,186	($11,700,522)	$42,604,665

		(A)	(B)	(C)	(D)
		Test Year 2024			
Line No.	Description	Regulatory Year 2024 Total Utility	Regulatory Year 2024 ND Jurisdiction	Adjustments	Test Year 2024 ND Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$487,865,956	$205,989,209	($23,206,374)	$182,782,835
2	Other Electric Operating Revenue	62,763,924	12,976,906	(723,227)	12,253,679
3	**TOTAL OPERATING REVENUE**	$550,629,880	$218,966,115	($23,929,601)	$195,036,514
	OPERATING EXPENSES				
4	Production Expenses	$195,857,531	$86,694,044	$1,560,859	$88,254,903
5	Transmission Expenses	$35,329,066	$13,847,298	239,257	$14,086,555
6	Distribution Expenses	$17,553,489	$7,972,703	420,528	$8,393,231
7	Customer Accounting Expenses	$16,028,499	$7,035,433	260,162	$7,295,595
8	Customer Service and Information Expenses	$12,470,633	$1,315,049	15,968	$1,331,017
9	Sales Expenses	$583,457	$135,872	(0)	$135,872
10	Administration and General Expenses	$43,893,859	$17,534,200	3,236,396	$20,770,596
11	Charitable Contributions	$0	$0	0	$0
12	Depreciation Expense	$79,405,970	$32,603,918	561,367	$33,165,285
13	General Taxes	$18,693,896	$7,102,692	820	$7,103,512
14	**TOTAL OPERATING EXPENSES**	$419,816,400	$174,241,209	$6,295,357	$180,536,566
15	**NET OPERATING INCOME BEFORE INCOME TAX**	$130,813,480	$44,724,906	($30,224,958)	$14,499,948
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($6,628,472)	($2,939,568)	($50)	($2,939,618)
18	Deferred Income Taxes	$17,836,409	$5,059,809	(7,610,123)	($2,550,314)
19	Income Taxes	$0	$0	0	$0
20	**TOTAL INCOME TAX EXPENSE**	$11,207,937	$2,120,241	($7,610,173)	($5,489,932)
21	**NET OPERATING INCOME**	$119,605,543	$42,604,666	($22,614,785)	$19,989,880
22	Allowance for Funds Used During Construction	0	0	0	0
23	**TOTAL AVAILABLE FOR RETURN**	$119,605,543	$42,604,666	($22,614,785)	$19,989,880

		(A)	(B)	(E)	(F)
		Regulatory Year 2024		Test Year 2024	
Line No.	Description	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction
	Income Before Taxes				
1	Total Operating Revenues	$550,629,880	$218,966,115	$527,423,506	$195,036,514
2	Less: Total Operating Expenses	(321,716,534)	(134,534,599)	(334,564,998)	(140,267,769)
3	Book Depreciation & Amortization	(79,405,970)	(32,603,918)	(80,703,774)	(33,165,285)
4	Taxes Other Than Income	(18,693,896)	(7,102,692)	(18,693,895)	(7,103,512)
5	Interest Cost	(39,572,606)	(14,205,888)	(42,309,280)	(15,160,261)
6	**Total Before Tax Book Income**	**$91,240,874**	**$30,519,018**	**$51,151,558**	**($660,313)**
7	Additional Tax Depreciation	$75,740,068	$28,643,159	75,740,068	$28,652,304
8	Other Schedule M Items	11,330,739	4,285,026	11,330,739	4,286,394
9	**Total Tax Deductions**	**$87,070,807**	**$32,928,185**	**$87,070,807**	**$32,938,698**
10	ND Adjustments to Federal Schedule M; ND Jurisdiction		1,671	(2,209)	1,671
11	**State Taxable Income**	**$4,170,067**	**($2,460,838)**	**($35,967,040)**	**($33,650,682)**
12	State Income Tax Rate		4.31%		4.31%
13	**Total State Income Taxes & Minimum Fee per statute ($10,210 in 2019)**	**($104,822)**	**($104,822)**	**($1,449,104)**	**($1,449,104)**
14	State Taxes Transferred to Deferred Income Taxes due to Net Operating Loss	**$104,822**	**$104,822**	**$2,102,095**	**1,449,104**
15	**Total State Income Taxes**	**$0**	**($0)**	**$652,991**	**$0**
16	**Federal Taxable Income**	**$4,170,067**	**($2,460,838)**	**($36,620,031)**	**($33,650,683)**
17	Addback of ND Adjustments to Federal Schedule M; ND Jurisdiction	(104,822)	(483,912)	2,102,095	1,449,104
18	**Adjusted Federal Taxable Income**	**$4,274,889**	**($2,304,345)**	**($34,517,936)**	**($32,149,907)**
19	Federal Income Tax Rate	21.00%	21.00%	21.00%	21.00%
20	**Total Federal Income Taxes**	**$897,727**	**($483,913)**	**($7,248,767)**	**($6,751,480)**
21	Federal Taxes Transferred to Deferred Income Taxes due to Net Operating Loss		**$483,913**	**$7,248,767**	**$6,751,480**
22	**Total Federal Income Taxes**	**$897,727**	**($0)**	**$0**	**($0)**
23	**Total State and Federal Income Tax**	**$897,727**	**$0**	**$652,991**	**($0)**

		(C)	(D)	(G)	(H)
		Regulatory Year 2024		Test Year 2024	
Line No.	Description	Total Utility	ND Jurisdiction	Total Utility	ND Jurisdiction
1	Removal Costs	501,805	$189,771	501,805	$189,832
2	Excess Tax Over Book Depreciation	13,446,714	$5,085,238	13,446,714	$5,086,863
3	Interest Capitlaized on Cosntruction	422,886	$159,926	422,886	$159,977
5	Other Capitalized Items	(12,057,350)	$108,787	2,694,869	$213,600
6	**TOTAL Deferred Income Taxes**	$2,314,055	$5,543,722	$17,066,274	$5,650,271
7	Transferred State and Federal Taxes due to Net Operating Loss	($104,822)	($483,913)	($9,350,862)	($8,200,584)
8	**TOTAL Deferred Income Taxes**	**$2,209,233**	**$5,059,809**	**$7,715,413**	**($2,550,313)**

DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES

Most Recent Actual Year	2022
Current Period	2023
Test Year	2024

Let: F=Federal Income Tax Rate = 21.00%

M=Minnesota State Income Tax Rate = 9.80%

D=North Dakota State Income Tax Rate = 4.31%

S=South Dakota Income Tax Rate = 0.00%

N=Net Income After Interest Deductions but Before Income Taxes

Jurisdictional:

Only Minnesota and Federal Income Taxes

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

Only North Dakota and Federal Income Taxes

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

Only South Dakota and Federal Income Taxes

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

Composite: Combined Minnesota, North Dakota, South Dakota and Federal Income Taxes.
M + D + S + F = 26.20% (N)

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

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE
Unadjusted Year 2024 to Regulatory Year 2024

Case No. PU-23-342
Exhibit (CLP-1), Schedule C-7
Page 1 of 2

			Adjustments																
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
Line No.	Description	Unadjusted Year 2024	**Advertising Expenses**	**Fuel Expense - Hoot Lake Solar**	**Non-Employee Director Restricted Stock**	**Economic Development Costs**	**Employe Recognition and Gifts**	**ESSRP**	**Electric Vehicles**	**GIPs**	**Hoot Lake Solar**	**Incentive Compensation**	**Investor Relations**	**Long-Term Incentive**	**PTC GAAP Provision**	**Rider CWIP Projects**	**Transmission Recovery**	Changes in Allocations due to Effect of Normal Adjustments	Regulatory Year 2024
1	**OPERATING REVENUES**																		
2	Retail Revenue	$203,210,040		$1,313,314											4,186,187	($2,720,332)		$0	$205,989,209
3	Other Electric Operating Revenue	$26,709,463								(1,688,273)							(12,044,474)	$190	$12,976,906
4	**TOTAL OPERATING REVENUE**	$229,919,503	$0	$1,313,314	$0	$0	$0	$0	$0	($1,688,273)	$0	$0	$0	$0	$4,186,187	($2,720,332)	($12,044,474)	$190	$218,966,115
5	**OPERATING EXPENSES**																		
6	Production Expenses	$85,426,089		$1,267,955														$0	$86,694,044
7	Transmission Expenses	$13,847,298																$0	$13,847,298
8	Distribution Expenses	$7,972,703																$0	$7,972,703
9	Customer Accounting Expenses	$7,035,433																$0	$7,035,433
10	Customer Service and Information Expenses	$1,315,049																$0	$1,315,049
11	Sales Expenses	$142,408	(594)			(5,943)												$1	$135,872
12	Administration and General Expenses	$20,022,371	($377,812)		(262,850)		(96,967)	(61,296)				(365,447)	(102,431)	(1,221,363)				($5)	$17,534,200
13	Charitable Contributions	$0																$0	$0
14	Depreciation Expense	$35,004,108							(78,037)	(311,858)	(685,029)						(1,325,266)	$0	$32,603,918
15	General Taxes	$8,019,087															(916,394)	($1)	$7,102,692
16	**TOTAL OPERATING EXPENSES**	$178,784,546	($378,406)	$1,267,955	($262,850)	($5,943)	($96,967)	($61,296)	($78,037)	($311,858)	($685,029)	($365,447)	($102,431)	($1,221,363)	$0	$0	($2,241,660)	($5)	$174,241,209
17	**NET OPERATING INCOME BEFORE INCOME T**	$51,134,957	$378,406	$45,359	$262,850	$5,943	$96,967	$61,296	$78,037	($1,376,415)	$685,029	$365,447	$102,431	$1,221,363	$4,186,187	($2,720,332)	($9,802,814)	$195	$44,724,906
18	**INCOME TAX EXPENSE**																		
19	Investment Tax Credit	($8,230,037)									$279,699				$5,010,974			($204)	($2,939,568)
20	Deferred Income Taxes	$5,059,807																$2	$5,059,809
21	Income Taxes	$0	$92,350	$11,070	$64,148	$1,450	$23,665	$14,959	$19,045	($335,913)	$167,181	$89,187	$24,998	$298,072	$1,021,635	($663,894)	($2,392,367)	$1,564,414	$0
22	**TOTAL INCOME TAX EXPENSE**	($3,170,230)	$92,350	$11,070	$64,148	$1,450	$23,665	$14,959	$19,045	($335,913)	$446,880	$89,187	$24,998	$298,072	$6,032,609	($663,894)	($2,392,367)	$1,564,212	$2,120,241
23	**NET OPERATING INCOME**	$54,305,187	$286,056	$34,289	$198,702	$4,493	$73,302	$46,337	$58,992	($1,040,502)	$238,149	$276,260	$77,433	$923,291	($1,846,422)	($2,056,438)	($7,410,447)	($1,564,017)	$42,604,665
24	Allowance for Funds Used During Construction	$0																$0	$0
25	**TOTAL AVAILABLE FOR RETURN**	$54,305,187	$286,056	$34,289	$198,702	$4,493	$73,302	$46,337	$58,992	($1,040,502)	$238,149	$276,260	$77,433	$923,291	($1,846,422)	($2,056,438)	($7,410,447)	($1,564,017)	$42,604,665

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE
Regulatory Year 2024 to Test Year 2024

			Adjustments																
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(k) Petersen	(L) Petersen	(M) Stalboerger	(N) Prazak	(O) Stalboerger	(P) Prazak	(Q)	(R)
Line No.	Description	Regulatory Year 2024	Rate Case Expenses	Normalize Langdon Upgrade Project	Normalize Pension and PRM	Non-Employee Director Restirced Stock	Rider Roll-In	ESSRP	Employe Recognition and Gifts	Investor Relations	Long-Term Inventive	Normalized Plant Outage	Noarmalized Langdon	Updated Renewable Rider Roll in	Lighting Revenue	RTP Bill Determinants	Irrigation Revenue	Changes in Allocations due to Effect of Test Year Adjustments	Test Year 2024
1	**OPERATING REVENUES**																		
2	Retail Revenue	$205,989,209					($23,302,321)							($6,629)	($100,737)	$200,931	$2,381	$95,947	$182,782,835
3	Other Electric Operating Revenue	$12,976,906																($723,227)	$12,253,679
4	**TOTAL OPERATING REVENUE**	$218,966,115	$0	$0	$0	$0	($23,302,321)	$0	$0	$0	$0							($627,280)	$195,036,514
5	**OPERATING EXPENSES**																		
6	Production Expenses	$86,694,044			414,420							$1,091,341						$1,146,439	$88,254,903
7	Transmission Expenses	$13,847,298			239,257													$0	$14,086,555
8	Distribution Expenses	$7,972,703			420,521													$7	$8,393,231
9	Customer Accounting Expenses	$7,035,433			260,162													($0)	$7,295,595
10	Customer Service and Information Expenses	$1,315,049			15,968													$0	$1,331,017
11	Sales Expenses	$135,872																($0)	$135,872
12	Administration and General Expenses	$17,534,200	$359,404		1,131,083	262,850		61,296	96,967	102,431	1,221,363							$1,002	$20,770,596
13	Charitable Contributions	$0																$0	$0
14	Depreciation Expense	$32,603,918		489,384									71,920					$71,983	$33,165,285
15	General Taxes	$7,102,692																$820	$7,103,512
16	**TOTAL OPERATING EXPENSES**	$174,241,209	$359,404	$489,384	$2,481,411	$262,850	$0	$61,296	$96,967	$102,431	$1,221,363							$1,220,251	$180,536,566
17	**NET OPERATING INCOME BEFORE INCOME T**	$44,724,906	($359,404)	($489,384)	($2,481,411)	($262,850)	($23,302,321)	($61,296)	($96,967)	($102,431)	($1,221,363)							($1,847,531)	$14,499,948
18	**INCOME TAX EXPENSE**																		
19	Investment Tax Credit	($2,939,568)																($50)	($2,939,618)
20	Deferred Income Taxes	$5,059,809																($7,610,123)	($2,550,314)
21	Income Taxes	$0	($87,712)	($136,495)	($605,586)	($64,148)	($5,686,908)	($14,959)	($23,665)	($24,998)	($298,072)							$6,942,544	($0)
22	**TOTAL INCOME TAX EXPENSE**	$2,120,241	($87,712)	($136,495)	($605,586)	($64,148)	($5,686,908)	($14,959)	($23,665)	($24,998)	($298,072)							($667,629)	($5,489,932)
23	**NET OPERATING INCOME**	$42,604,665	($271,692)	($352,889)	($1,875,825)	($198,702)	($17,615,413)	($46,337)	($73,302)	($77,433)	($923,291)							($1,179,902)	$19,989,881
24	Allowance for Funds Used During Construction	$0		(69,911)														$69,911	$0
25	**TOTAL AVAILABLE FOR RETURN**	$42,604,665	($271,692)	($422,799)	($1,875,825)	($198,702)	($17,615,413)	($46,337)	($73,302)	($77,433)	($923,291)							($1,109,992)	$19,989,882

Summary of Approach used and Assumptions Made to the Operating Statements

	Test Year 2024
Item of Operating Income	**Narration**
Operating Revenues	Revenue for the Proposed Test Year 2024 is forecasted revenue. Revenues were adjusted as listed in schedule C-7 for the following adjustments: Rider Revenue Removal
Operating Expenses	Expenses for the Proposed Test Year 2024 were developed by first using allocated expenses for the period. Jurisdicational Allocation methodologies are discussed in Exhibit__(CLP-1), Schedule 2. These expenses were then adjusted through the required and rate case adjustments as listed in Schedule C-7. Refer to Schedule C-9 (all pages) for more details on how costs were allocated to North Dakota
Depreciation and Amortization Expense	Depreciation and Amortization Expenses for the Proposed Test Year 2024 were developed by first using allocated (Jurisdicational Allocation methodologies are discussed in Exhibit__(CLP-1), Schedule 2 expenses for the period. These expenses were then adjusted through the required and rate case adjustments as listed in Schedule C-7.
Taxes Other Than Income	Taxes other than Income Taxes for the Test Year were developed by using expenses as allocated (Jurisdicational Allocation methodologies are discussed in Exhibit__(CLP1), Schedule 2) for the period. These expenses were then adjusted through the required and rate case adjustments as listed in Schedule C-7.
Federal and State Income Taxes	Current taxes are determined by taking "Operating Income Before Taxes" for the jurisdiction and reducing it by the jurisdictional "Schedule M's" and interest expense (using the interest synchronization method) to arrive at taxable income. Current taxes are then computed using jurisdictional tax rates.

The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules. Accounts not on this page have been directly assigned to jurisdictions. Descriptions under the Allocation Factor column with a / means the first method was used in historic actual and projected, the method after the / is used in the test year.

The following allocation factors are used to compute North Dakota jurisdictional amounts for Expenses as listed below.

For a full description of each allocation factor, see OTP's *Cost Allocations Procedures Manual for Jurisdictional and Class Cost of Service Studies* , Amber Stalboerger's testimony, Exhibit ___(AMS-1), Schedules 2 and 3.

Line No.	Description	Allocation Basis
	ELEMENT OF OPERATING INCOME	
1	Operating Revenues	
2	Sales of Electricity	Direct Assignment (R10)
3	Other Operating Revenues	
4	Municipalities	Direct Assignment (FERC only)
5		
6	Other Electric Revenues	
7	Late Fees	
8	Connection Fees	Direct Assignment
9	Wheeling	Direct Assignment (FERC only)
10	Income - Rent	Total Net Plant in Service Ratio (NEPIS)
11	Integrated Transmission Agreements	Total Net Plant in Service Ratio (NEPIS)
12	Load Control and Dispatch (also MISO Trans Rev.)	Total Net Plant in Service Ratio Excluding Direct Assignment (NEPIS EXDA)
13	All Other	Total Net Plant in Service Ratio (NEPIS)
14	Loan Pool Interest	Directly assigned to Jurisdiction
15		
16	Operating Expenses	
17	Production Expenses	
18	Production and Purchase Expenses	
19	Base Demand	kwh Sales Factor (E1)
20	Peak Demand	Generation Demand Factor (D1)
21	Base Energy	kwh Sales Factor (E2)
22	Peak Energy	Generation Demand Factor (D1)
23		
24	Transmission Expenses	Transmission Demand Factor (D2)
25		
26	Distribution Expenses	
27	Primary Demand	Distribution Primary Demand Factor (D3)
28	Secondary Demand	Distribution Secondary Demand Factor (D4)
29	Primary Customer	Total Retail Service Locations Factor (C2)
30	Secondary Customer	Total Secondary Retail Service Locations Factor (C3)
31	Streetlighting	Streetlight Factor (C4)
32	Area Lighting	Area Light Factor (C5)
33	Meters	Meter Factor (C6)
34	Load Management Expenses	Load Management Factor (C9)
35		
36	Customer Accounts Expenses	
37	Meter Reading	Meter Reading Factor (C7)
38	Other	Total System Service Locations Factor (C8)

Line No.	Description	Allocation Basis
	ELEMENT OF OPERATING INCOME	ALLOCATION FACTOR
1	Operating Expenses - continued	
2	Customer Service & Informational	
3	Expenses	
4	Conservation & Promotional Rebates	Direct Assignment / E2
5	Customer Assistance Expenses	Direct Assignment / C1
6	All Other	Total Retail Customers Factor (C1)
7		
8	Sales Expenses	
9	Off-Peak Development	Direct Assignment
10	All Other	Total Retail Customers Factor (C1)
11		
12	Administrative and General Expenses	
13	A & G Salaries, Office Supplies &	
14	Exp., & Employee Pensions & Benefits	
15	Production	Production Expense Ratio (Excl. Energy
16		Related) (OXPD)
17	Transmission	Transmission Expense Ratio (D2)
18	Distribution	Distribution Expense Ratio (OXD)
19	Customer Accounts	Customer Accounts Expense Ratio (OXC)
20	Customer Service & Informational	Customer Service & Informational Expense (C1)
21		Ratio (OXI)
22	Load Management Expenses	Load Management Factor (C9)
23	Outside Services	Total Net Plant in Service Ratio (NEPIS)
24	Property Insurance	Total Net Plant in Service Ratio (NEPIS)
25	Injuries and Damages	Total Net Plant in Service Ratio (NEPIS)
26		
27	Regulatory Commission Expenses	Direct Assignment
28	General Advertising	Total Retail Customers Factor (C1)
29	Miscellaneous General Expenses, Rents	
30	and Maintenance of General Plant	General Plant in Service Ratio (P90)
31		
32	Charitable Contributions	Direct Assignment
33		
34	Depreciation Expenses	
35	Production	
36	Base Demand	kwh Sales Factor (E1)
37	Peak Demand	Generation Demand Factor (D1)
38	Base Energy	kwh Sales Factor (E2)
39	Transmission	Transmission Demand Factor (D2)
40	Distribution	P60
41	General	General Plant in Service Ratio (P90)
42	Intangible	General Plant in Service Ratio (P90)
43		
44	General Taxes	Total Net Plant in Service Ratio Excluding Direct Assignment (NEPIS EXDA) / Total Net Plant in Service Ratio (NEPIS)
45	General Taxes (Direct Ferc)	Direct FERC
46	Other Expense	Direct / Gross Production Plant in Service Ratio (P10)

Line No.	Description	Allocation Basis
	ELEMENT OF OPERATING INCOME	ALLOCATION FACTOR
1	Operating Expenses - continued	
2	Investment Tax Credit	
3	Amortization of Prior Years' Credits	Total Gross Plant in Service Ratio (EPIS)
4	Debits Utilized	Federal Income Taxes Before Credits (EPIS)
5	Production Tax Credits	kwh Sales Factor (E2)
6		
7	Deferred Income Tax Expense	
8	Items South Dakota flows through:	
9	Federal	Total Net Plant in Service Ratio
10		excluding South Dakota (NPMNR)
11	Minnesota	Total Net Plant in Service - MN Ratio
12		(NPISM)
13	North Dakota	Total Net Plant in Service - ND Ratio
14		(NPISN)
15		
16	All Other:	
17	Federal - transfer from Current Income Taxes - NOL	Direct/Total Net Plant in Service Ratio (NEPIS)
18	Federal	Total Net Plant in Service Ratio (NEPIS)
19	Minnesota - transfer from Current Income Taxes - NOL	Direct/Total Net Plant in Service - MN Ratio (NPISM)
20	Minnesota	Total Net Plant in Service - MN Ratio
21		(NPISM)
22	North Dakota - transfer from Current Income Taxes - NOL	Direct/Total Net Plant in Service - ND Ratio (NPISN)
23	North Dakota	Total Net Plant in Service - ND Ratio
24		(NPISN)
25		
26	Income Taxes	
27	Federal - transfer to Deferred Income Taxes - NOL	
28	Federal Income Taxes	Separately Calculated by Jurisdiction
29	Minnesota - transfer to Deferred Income Taxes - NOL	
30	Minnesota Income Taxes	Separately Calculated by Jurisdiction
31	North Dakota - transfer to Deferred Income Taxes - NOL	
32	North Dakota Income Taxes	Separately Calculated by Jurisdiction
33		
34	Allowance for Funds Used	
35	During Construction	Other Construction Work in Progress Ratio
36		(CWIP Accruing AFDC) (CWIPLT)
37		
38	NOTE: See Schedule C-9, Pages 4 and 5 for allocation factor values	

Allocators - Demand, Energy and Customer

			Most Recent Actual Year 2022			Current Period 2023		
Line No.	Item	Factor	Total Utility	ND Jurisdiction	All Other	Total Utility	ND Jurisdiction	All Other
1	MWH Consumption at Generators - Partial	E1 / E1-E8760	5,477,199	2,176,780	3,300,419	5,828,855	2,463,270	3,365,585
2	Percentage		100.000000%	39.742576%	60.257424%	100.000000%	42.259929%	57.740071%
3	MWH Consumption at Generators - Total	E2 / E2-E8760	6,047,550	2,506,064	3,541,486	6,388,235	2,786,350	3,601,885
4	Percentage		100.000000%	41.439327%	58.560673%	100.000000%	43.616899%	56.383101%
5	Generation Demand Factor	D1	744,816	288,255	456,561	732,267	292,412	439,855
6	Percentage		100.000000%	38.701505%	61.298495%	100.000000%	39.932429%	60.067571%
7	Transmission Demand Factor	D2	749,267	288,255	461,012	737,663	292,412	445,251
8	Percentage		100.000000%	38.471600%	61.528400%	100.000000%	39.640324%	60.359676%
9	Distribution - Primary Demand Factor	D3	855,471	390,364	465,107	849,891	389,743	460,148
10	Percentage		100.000000%	45.631471%	54.368529%	100.000000%	45.857998%	54.142002%
11	Distribution - Secondary Demand Factor	D4	1,059,385	510,894	548,491	1,103,719	518,815	584,904
12	Percentage		100.000000%	48.225527%	51.774473%	100.000000%	47.006077%	52.993923%
13	Customer or Meter Factors							
14	Total Retail Customers	C1	134,621	59,558	75,063	135,015	59,590	75,425
15	Percentage		100.000000%	44.241240%	55.758760%	100.000000%	44.135837%	55.864163%
16	Retail Service Locations	C2	135,654	59,558	76,096	136,049	59,600	76,449
17	Percentage		100.000000%	43.904345%	56.095655%	100.000000%	43.807746%	56.192254%
18	Secondary Service Locations	C3	135,615	59,548	76,067	136,014	59,590	76,424
19	Percentage		100.000000%	43.909597%	56.090403%	100.000000%	43.811666%	56.188334%
20	Street Lighting Factor	C4	13,235,267	5,515,574	7,719,693	13,235,267	5,515,574	7,719,693
21	Percentage		100.000000%	41.673311%	58.326689%	100.000000%	41.673311%	58.326689%
22	Area Lighting Factor	C5	9,628,628	5,249,227	4,379,401	9,628,628	5,249,227	4,379,401
23	Percentage		100.000000%	54.516874%	45.483126%	100.000000%	54.516874%	45.483126%
24	Meter Factor	C6	57,578,353	25,668,459	31,909,894	57,578,353	25,668,459	31,909,894
25	Percentage		100.000000%	44.580051%	55.419949%	100.000000%	44.580051%	55.419949%
26	Meter Reading Factor	C7	205,116	90,998	114,118	205,638	91,075	114,563
27	Percentage		100.000000%	44.364165%	55.635835%	100.000000%	44.288993%	55.711007%
28	System Service Locations	C8	135,662	59,559	76,103	136,057	59,601	76,456
29	Percentage		100.000000%	43.902493%	56.097507%	100.000000%	43.805905%	56.194095%
30	Load Management Factor	C9	41,948	18,352	23,596	41,706	18,234	23,472
31	Percentage		100.000000%	43.749404%	56.250596%	100.000000%	43.720328%	56.279672%

Allocators - Demand, Energy and Customer

Line No.	Item	Factor	Test Year 2024 Total Utility	ND Jurisdiction	All Other
1	MWH Consumption at Generators - Partial	E1 / E1-E8760	5,645,126	2,476,736	3,168,390
2	Percentage		100.000000%	43.873883%	56.126117%
3	MWH Consumption at Generators - Total	E2 / E2-E8760	6,171,457	2,775,986	3,395,471
4	Percentage		100.000000%	44.981047%	55.018953%
5	Generation Demand Factor	D1	719,976	284,282	435,694
6	Percentage		100.000000%	39.484927%	60.515073%
7	Transmission Demand Factor	D2	725,298	284,282	441,016
8	Percentage		100.000000%	39.195200%	60.804800%
9	Distribution - Primary Demand Factor	D3	851,393	396,080	455,313
10	Percentage		100.000000%	46.521407%	53.478593%
11	Distribution - Secondary Demand Factor	D4	1,119,241	545,068	574,173
12	Percentage		100.000000%	48.699789%	51.300211%
13	Customer or Meter Factors				
14	Total Retail Customers	C1	135,411	59,643	75,768
15	Percentage		100.000000%	44.045905%	55.954095%
16	Retail Service Locations	C2	136,449	59,642	76,807
17	Percentage		100.000000%	43.710104%	56.289896%
18	Secondary Service Locations	C3	136,414	59,632	76,782
19	Percentage		100.000000%	43.713988%	56.286012%
20	Street Lighting Factor	C4	13,235,267	5,515,574	7,719,693
21	Percentage		100.000000%	41.673311%	58.326689%
22	Area Lighting Factor	C5	9,628,628	5,249,227	4,379,401
23	Percentage		100.000000%	54.516874%	45.483126%
24	Meter Factor	C6	57,578,353	25,668,459	31,909,894
25	Percentage		100.000000%	44.580051%	55.419949%
26	Meter Reading Factor	C7	206,170	91,157	115,013
27	Percentage		100.000000%	44.214483%	55.785517%
28	System Service Locations	C8	136,457	59,643	76,814
29	Percentage		100.000000%	43.708274%	56.291726%
30	Load Management Factor	C9	41,469	18,119	23,350
31	Percentage		100.000000%	43.692879%	56.307121%

Allocators - General Plant, Operation and Maintenance Expense and Taxes

			Most Recent Actual Year 2022			Current Period 2023		
Line No.	Item	Factor	Total Utility	ND Jurisdiction	All Other	Total Utility	ND Jurisdiction	All Other
1	Production Plant	P10	1,336,122,578	535,749,544	800,373,034	1,396,605,647	586,915,725	809,689,922
2	Percentage		100.000000%	40.097335%	59.902665%	100.000000%	42.024442%	57.975558%
3	Distribution Plant	P60	594,253,855	271,503,168	322,750,687	650,211,687	295,374,578	354,837,109
4	Percentage		100.000000%	45.688078%	54.311922%	100.000000%	45.427448%	54.572552%
5	General Plant	P90	106,022,339	44,822,076	61,200,262	113,108,289	48,655,555	64,452,734
6	Percentage		100.000000%	42.276068%	57.723932%	100.000000%	43.016790%	56.983210%
7	Electric Plant in Service	EPIS	2,808,691,578	1,041,850,025	1,766,841,553	2,979,345,803	1,148,337,185	1,831,008,618
8	Percentage		100.000000%	37.093785%	62.906215%	100.000000%	38.543266%	61.456734%
9	Net Electric Plant in Service	NEPIS	1,844,282,690	650,618,846	1,193,663,844	1,955,239,414	722,626,540	1,232,612,874
10	Percentage		100.000000%	35.277610%	64.722390%	100.000000%	36.958468%	63.041532%
11	Assignment	NEPIS EXDA	1,580,979,545	650,618,846	930,360,699	1,707,469,253	722,626,540	984,842,713
12	Percentage		100.000000%	41.152895%	58.847105%	100.000000%	51.030000%	48.970000%
13	Operation and Maintenance Expense							
14	Production Expense (Excl Energy)	OXPD	22,808,745	9,002,304	13,806,441	22,830,396	9,473,734	13,356,662
15	Percentage		100.000000%	39.468650%	60.531350%	100.000000%	41.496146%	58.503854%
16	Distribution Expense	OXD	17,303,680	7,838,847	9,464,834	16,933,996	7,648,887	9,285,109
17	Percentage		100.000000%	45.301615%	54.698385%	100.000000%	45.168823%	54.831177%
18	Customer Accounts Expense	OXC	14,027,785	6,186,536	7,841,249	15,247,193	6,709,753	8,537,440
19	Percentage		100.000000%	44.102016%	55.897984%	100.000000%	44.006481%	55.993519%
20	Customer Service & Information Expense	OXI	2,640,694	1,168,276	1,472,418	2,799,489	1,235,785	1,563,704
21	Percentage		100.000000%	44.241240%	55.758760%	100.000000%	44.143243%	55.856757%
22	Other Deferred Income Tax Factor							
23	Minnesota	NPISM	1,038,294,699	0	1,038,294,699	569,482,680	0	569,482,680
24	Percentage		100.000000%	0.000000%	100.000000%	100.000000%	0.000000%	100.000000%
25	North Dakota	NPISN	650,618,846	650,618,846	0	481,698,161	474,856,379	6,841,782
26	Percentage		100.000000%	100.000000%	0.000000%	100.000000%	98.579654%	1.420346%
27	Excluding South Dakota	NPMNR	1,688,913,545	650,618,846	1,038,294,699	1,787,649,542	722,626,540	1,065,023,002
28	Percentage		100.000000%	38.522922%	61.477078%	100.000000%	40.423278%	59.576722%
29	Long-Term CWIP Ratio (W/AFDC)	CWIPLT	78,640,439	0	78,640,439	0	0	0
30	Percentage		100.000000%	0.000000%	100.000000%	0.000000%	0.000000%	0.000000%
31	Revenue	R10	462,806,067	186,549,483	276,256,584	0	0	0
32	Percentage		100.000000%	40.308349%	59.691651%	0.000000%	0.000000%	0.000000%
33	Labor and Related Expense	LRE	152,936,981	58,665,955	94,271,026	143,469,858	59,405,107	84,064,752
34	Percentage		100.000000%	38.359561%	61.640439%	100.000000%	41.405984%	58.594016%

Allocators - General Plant, Operation and Maintenance Expense a

Line No.	Item	Factor	Test Year 2024 Total Utility	ND Jurisdiction	All Other
1	Production Plant	P10	1,474,611,883	634,293,600	840,318,283
2	Percentage		100.000000%	43.014274%	56.985726%
3	Distribution Plant	P60	717,695,529	329,751,162	387,944,367
4	Percentage		100.000000%	45.945829%	54.054171%
5	General Plant	P90	122,942,613	53,301,572	69,641,041
6	Percentage		100.000000%	43.354839%	56.645161%
7	Electric Plant in Service	EPIS	3,182,095,021	1,251,434,477	1,930,660,543
8	Percentage		100.000000%	39.327376%	60.672624%
9	Net Electric Plant in Service	NEPIS	2,088,418,443	790,044,182	1,298,374,262
10	Percentage		100.000000%	37.829784%	62.170216%
11	Net Electric Plant in Service Excluding Direct Assignment	NEPIS EXDA	1,841,633,693	790,044,182	1,051,589,511
12	Percentage		100.000000%	42.899095%	57.100905%
13	Operation and Maintenance Expense				
14	Production Expense (Excl Energy)	OXPD	26,965,239	11,444,689	15,520,550
15	Percentage		100.000000%	42.442381%	57.557619%
16	Distribution Expense	OXD	18,488,356	8,393,231	10,095,125
17	Percentage		100.000000%	45.397391%	54.602609%
18	Customer Accounts Expense	OXC	16,621,213	7,295,595	9,325,619
19	Percentage		100.000000%	43.893273%	56.106727%
20	Customer Service & Information Expense	OXI	3,021,886	1,331,017	1,690,869
21	Percentage		100.000000%	44.045905%	55.954095%
22	Other Deferred Income Tax Factor				
23	Minnesota	NPISM	921,398,315	0	921,398,315
24	Percentage		100.000000%	0.000000%	100.000000%
25	North Dakota	NPISN	1,044,150,583	790,044,183	254,106,399
26	Percentage		100.000000%	98.687840%	1.312160%
27	Excluding South Dakota	NPMNR	1,905,077,359	790,044,182	1,115,033,177
28	Percentage		100.000000%	41.470451%	58.529549%
29	Long-Term CWIP Ratio (W/AFDC)	CWIPLT	0	0	0
30	Percentage		100.000000%	0.000000%	0.000000%
31	Revenue	R10	464,659,581	182,782,835	281,876,746
32	Percentage		100.000000%	39.336934%	60.663066%
33	Labor and Related Expense	LRE	151,972,523	63,326,540	88,645,983
34	Percentage		100.000000%	41.669730%	58.330270%

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D. Rate of Return / Cost of Capital Schedules

RATE OF RETURN COST OF CAPITAL SCHEDULES
SUMMARY SCHEDULE

	(A)	(B)	(C)	(D)
Capitalization:	**Amount**	**Percent of Total**	**Cost of Debt / Return on Equity**	**Weighted Cost / Return**
MOST RECENT FISCAL YEAR 2022				
Long-Term Debt	$726,995,487	44.9%	4.38%	1.96%
Short-Term Debt	24,008,904	1.5%	2.55%	0.04%
Long-Term and Short-Term Debt	$751,004,391	46.4%	4.36%	2.02%
Common Equity	869,224,856	53.6%	9.77%	5.24%
Total Capitalization	$1,620,229,247	100.0%		7.26%
PROJECTED FISCAL YEAR 2023				
Long-Term Debt	$753,348,885	43.2%	4.27%	1.85%
Short-Term Debt	57,091,400	3.3%	6.93%	0.23%
Long-Term and Short-Term Debt	$810,440,285	46.5%	4.46%	2.07%
Common Equity	932,599,299	53.5%	9.77%	5.23%
Total Capitalization	$1,743,039,584	100.0%		7.30%
TEST YEAR 2024				
Long-Term Debt	$844,276,580	55.1%	4.66%	2.57%
Short-Term Debt	57,841,876	3.0%	5.25%	0.16%
Long-Term and Short-Term Debt	$902,118,455	46.5%	4.68%	2.18%
Common Equity	1,037,715,500	53.5%	10.60%	5.67%
Total Capitalization	$1,939,833,956	100.0%		7.85%

Most recent fiscal year and projected fiscal year are based on 13-month average balances except some short-term debt uses daily balances.
(1) Based on 2024 budget prepared in 2023.

MOST RECENT FISCAL YEAR 2022

Description	Interest Rate	PRINCIPAL AMOUNTS OUTSTANDING Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Average Monthly Balance	Interest Cost
DEBENTURES																
Series for 2021	4.63%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unsecured Series A 2017 Senior Notes	5.95%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unsecured Series B 2022 Senior Notes	6.15%	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	0	0	0	0	0	18,461,538	1,178,750
Unsecured Series C 2027 Senior Notes	6.37%	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	2,675,400
Series D 2037 Unsecured Senior Notes	6.47%	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	$50,000,000	3,235,000
$10 Million - 10 Year Issuance	2.59%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	307,000
$26 Million - 20 Year Issuance	3.52%	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	915,200
$64 Million - 30 Year Issuance	3.82%	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	2,444,800
$10 Million - 10 Year Issuance	3.22%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	322,000
$10 Million - 20 Year Issuance	3.62%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	362,000
$15 Million - 30 Year Issuance	3.92%	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	588,000
$40 Million - 10 Year Issuance	2.74%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	1,288,000
$40 Million - 10 Year Issuance	2.74%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	1,096,000
$100 Million - 30 Year Issuance	3.69%	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	3,690,000
$90 Million - 30 Year Issuance	3.77%	0	0	0	0	0	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	55,384,615	2,073,500
TOTAL DEBENTURES		$437,000,000	$437,000,000	$437,000,000	$437,000,000	$437,000,000	$527,000,000	$527,000,000	$527,000,000	$497,000,000	$497,000,000	$497,000,000	$497,000,000	$497,000,000	$480,846,154	$20,175,650
Pollution Control Revenue Bonds																
2028 Series	4.68%	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$2,808,000
2043 Series	5.47%	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$90,000,000	$4,923,000
2044 Series	4.07%	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$4,070,000
		$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$250,000,000	$11,801,000
Subtotal Bond Balances		$437,000,000	$437,000,000	$437,000,000	$437,000,000	$437,000,000	$527,000,000	$527,000,000	$527,000,000	$497,000,000	$497,000,000	$497,000,000	$497,000,000	$497,000,000	$730,846,154	$31,976,650
LOSS/GAIN ON REACQUIRED DEBT		($4,021,370)	($3,976,373)	($3,932,074)	($3,888,961)	($3,845,848)	($3,822,561)	($3,793,516)	($3,754,816)	($3,716,280)	($3,709,922)	($3,896,357)	($3,867,114)	($3,833,481)	($3,850,667)	$474,645
TOTAL DEBT CAPITAL		$432,978,630	$433,023,627	$433,067,926	$433,111,039	$433,154,152	$523,177,439	$523,206,484	$523,245,184	$493,283,720	$493,290,078	$493,103,643	$493,132,886	$493,166,519	$726,995,487	$32,451,295

Embedded Cost of Long-Term Debt	4.38%

PROJECTED FISCAL YEAR 2023

Description	Interest Rate	PRINCIPAL AMOUNTS OUTSTANDING Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Average Monthly Balance	Interest Cost
DEBENTURES																
Unsecured Series C 2027 Senior Notes	6.37%	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	2,675,400
Unsecured Series D 2037 Senior Notes	6.47%	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	3,235,000
															10,000,000	
Unsecured Series A 2029	4.68%	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	2,808,000
Unsecured Series A 2029 Senior Note	3.07%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	$10,000,000	307,000
Unsecured Series A 2030 Senior Note	3.22%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	322,000
Unsecured Series A 2031 Senior Note	2.74%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	1,096,000
Unsecured Series A 2048	4.07%	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	4,070,000
Unsecured Series B 2030 Senior Note	3.22%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	1,288,000
Unsecured Series B 2039 Senior Note	3.52%	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	915,200
Unsecured Series B 2044	5.47%	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	4,603,000
Unsecured Series B 2051 Senior Note	3.69%	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	3,690,000
Unsecured Series C 2040 Senior Note	3.62%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	362,000
Unsecured Series C 2049 Senior Note	3.82%	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	2,444,800
Unsecured Series C 2052 Senior Note	3.77%	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	3,393,000
Unsecured Series D 2050 Senior Note	3.92%	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	588,000
TOTAL DEBENTURES		$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$747,000,000	$757,000,000	$31,797,400
LOSS/GAIN ON REACQUIRED DEBT		(3,850,668)	(3,833,638)	(3,817,493)	(3,805,815)	(3,794,809)	(3,784,475)	(3,773,428)	(3,758,467)	(3,744,195)	(3,730,599)	(3,715,203)	(3,683,179)	(3,651,115)	($3,651,115)	383,189
TOTAL DEBT CAPITAL		$743,149,332	$743,166,362	$743,182,507	$743,194,185	$743,205,191	$743,215,525	$743,226,572	$743,241,533	$743,255,805	$743,269,401	$743,284,797	$743,316,821	$743,348,885	$753,348,885	$32,180,589

Embedded Cost of Long-Term Debt	4.27%

TEST YEAR 2024

Description	Interest Rate	PRINCIPAL AMOUNTS OUTSTANDING Dec 2023	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024	Jul 2024	Aug 2024	Sep 2024	Oct 2024	Nov 2024	Dec 2024	Average Monthly Balance	Interest Cost
Unsecured Series C 2027 Senior Notes	6.37%	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	42,000,000	2,675,400
Unsecured Series D 2037 Senior Notes	6.47%	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	3,235,000
Forecasted Long Term Debt	6.30%	0	0	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	101,538,462	6,689,999
Unsecured Series A 2029	4.68%	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	2,808,000
Unsecured Series A 2029 Senior Note	3.07%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	307,000
Unsecured Series A 2030 Senior Note	3.22%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	322,000
Unsecured Series A 2031 Senior Note	2.74%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	1,096,000
Unsecured Series A 2048	4.07%	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	4,070,000
Unsecured Series B 2030 Senior Note	3.22%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	1,288,000
Unsecured Series B 2039 Senior Note	3.52%	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	915,200
Unsecured Series B 2044	5.47%	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	4,923,000
Unsecured Series B 2051 Senior Note	3.69%	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	3,690,000
Unsecured Series C 2040 Senior Note	3.62%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	362,000
Unsecured Series C 2049 Senior Note	3.82%	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	2,444,800
Unsecured Series C 2052 Senior Note	3.77%	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	3,393,000
Unsecured Series D 2050 Senior Note	3.92%	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	588,000
TOTAL DEBENTURES		$747,000,000	$747,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$867,000,000	$848,538,462	$38,807,399
LOSS/GAIN ON REACQUIRED DEBT		(3,651,115)	(3,619,351)	(3,679,799)	(3,740,152)	(3,796,775)	(3,853,370)	(3,909,937)	(3,966,337)	(4,026,213)	(4,085,705)	(4,144,815)	(4,203,540)	(4,261,882)	($4,261,882)	$411,810
TOTAL DEBT CAPITAL		$743,348,885	$743,380,649	$863,320,201	$863,259,848	$863,203,225	$863,146,630	$863,090,063	$863,033,663	$862,973,787	$862,914,295	$862,855,185	$862,796,460	$862,738,118	$844,276,580	$39,219,209

Embedded Cost of Long-Term Debt	4.65%

MOST RECENT FISCAL YEAR 2022

Description	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Average Monthly Balances	Interest Cost
	PRINCIPAL AMOUNTS OUTSTANDING														
Line of credit (short-term debt)	68,525,649	74,233,175	60,336,497	54,489,106	46,327,689	0	0	0	0	0	0	0	8,203,643	$24,008,904	
Interest						$0	$0	$0		$0					611,862
Embedded Cost of Short-Term Debt															2.55%

Notes: Short-Term (S-T) Debt was calculated using a daily average and was combined with actual interest charged to arrive at the S-T Cost of Debt.
August 2019 interest expense was credited due to the refund of overcharged usage fees.

PROJECTED FISCAL YEAR 2023

Description	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Average Monthly Balances	
	PRINCIPAL AMOUNTS OUTSTANDING														
Line of credit (short-term debt)	8,203,643	58,983,485	49,687,230	60,854,209	52,000,000	40,000,000	50,196,844	56,319,700	47,295,623	70,268,292	70,906,695	78,560,976	98,911,503	$57,091,400	
Interest		$311,721	$191,111	$331,804	$303,957	$235,302	$277,744	$293,845	$303,747	$340,177	$431,761	$428,684	$504,588		3,954,441
Embedded Cost of Short-Term Debt															6.93%

Note: Short-Term (S-T) Debt was calculated using a daily average and was combined with actual interest charged to arrive at the S-T Cost of Debt.

TEST YEAR 2024

Description	Dec 2023	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024	Jul 2024	Aug 2024	Sep 2024	Oct 2024	Nov 2024	Dec 2024	Average Monthly Balances	
	PRINCIPAL AMOUNTS OUTSTANDING														
Line of credit (short-term debt)	98,911,504	149,149,431	17,591,775	34,081,902	45,979,848	62,944,014	0	8,695,135	33,526,371	57,349,005	65,252,487	77,590,726	100,872,190	$57,841,876	
Interest		$555,524	$378,779	$128,203	$190,232	$253,004	$142,018	$24,266	$108,819	$214,731	$308,924	$327,959	$405,330		$3,037,787
Embedded Cost of Short-Term Debt															5.25%

Note: Short-Term (S-T) Debt was calculated using a daily average and was combined with actual interest charged to arrive at the S-T Cost of Debt.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity

MOST RECENT FISCAL YEAR 2022

PRINCIPAL AMOUNTS OUTSTANDING

Description	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022
Common Stock Balance	$586,989,466	$586,989,466	$586,989,466	$586,989,466	$586,989,466	$586,989,466	$586,989,466
End of Month Balance	$245,699,148	$252,995,205	$260,497,397	$251,236,090	$255,992,726	$264,339,903	$256,390,185
Total Electric Common Equity	$832,688,614	$839,984,671	$847,486,863	$838,225,556	$842,982,192	$851,329,369	$843,379,651

Description	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Average Monthly Balances
Common Stock Balance	$586,989,466	$636,989,466	$636,989,466	$636,989,466	$636,989,466	$636,989,466	$606,220,235
End of Month Balance	$264,542,876	$273,595,100	$267,533,530	$273,678,189	$281,694,003	$270,865,715	$263,004,621
Total Electric Common Equity	$851,532,342	$910,584,566	$904,522,996	$910,667,655	$918,683,469	$907,855,181	$869,224,856

PROJECTED FISCAL YEAR 2023

PRINCIPAL AMOUNTS OUTSTANDING

Description	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023
Common Stock Balance	$636,989,466	$636,989,466	$636,989,466	$636,989,466	$636,989,466	$636,989,466	$636,989,466
End of Month Balance	$272,441,845	$280,113,462	$288,034,460	$281,072,824	$285,763,847	$293,015,640	$286,107,844
Total Electric Common Equity	$909,431,311	$917,102,927	$925,023,926	$918,062,289	$922,753,313	$930,005,105	$923,097,309

Description	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Average Monthly Balances
Common Stock Balance	$636,989,466	$676,989,466	$676,989,466	$676,989,466	$676,989,466	$676,989,466	$652,374,081
End of Month Balance	$294,523,536	$302,550,970	$292,813,234	$297,796,079	$305,338,691	$293,355,399	280,225,218
Total Electric Common Equity	$931,513,001	$979,540,436	$969,802,700	$974,785,545	$982,328,157	$970,344,865	$932,599,299

TEST YEAR 2024

PRINCIPAL AMOUNTS OUTSTANDING

Description	Dec 2023	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024
Common Stock Balance	$676,989,466	$676,989,466	$676,989,466	$676,989,466	$676,989,466	$676,989,466	$777,689,466
Retained Earnings End of Month Balance	$293,355,399	$303,696,141	$311,730,002	$299,324,635	$304,352,591	$309,526,905	$298,110,193
Total Electric Common Equity	$970,344,865	$980,685,607	$988,719,467	$976,314,101	$981,342,057	$986,516,371	$1,075,799,658

Description	Jul 2024	Aug 2024	Sep 2024	Oct 2024	Nov 2024	Dec 2024	Average Monthly Balances
Common Stock Balance	$777,689,466	$777,689,466	$777,689,466	$777,689,466	$777,689,466	$777,689,466	$704,450,504
Retained Earnings End of Month Balance	$306,796,156	$315,042,741	$304,695,604	$310,267,471	$318,386,651	$309,253,958	$306,502,957
Total Electric Common Equity	$1,084,485,621	$1,092,732,206	$1,082,385,070	$1,087,956,937	$1,096,076,116	$1,086,943,424	$1,037,715,500

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E. Rate Structure and Design Information

Test Year 2024 Operating Revenue Summary Comparison - By Rate Schedule

Line No.	Rate Schedule	Operating Revenues Present	Operating Revenues Proposed	Difference	Percent Change
1	9.01 Residential Service (Rate 101)	$ 32,153,465	$ 45,174,002	$ 13,020,537	40.49%
2	9.02 Residential Demand Control (Rate 241)	$ 4,780,572	$ 6,963,486	$ 2,182,914	45.66%
3	Total Residential:	$ 36,934,038	$ 52,137,488	$ 15,203,450	41.16%
4					
5	9.03 Farm Service (Rate 361)	$ 1,830,773	$ 2,618,128	$ 787,355	43.01%
6	Total Farm:	$ 1,830,773	$ 2,618,128	$ 787,355	43.01%
7					
8	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)	$ 7,779,957	$ 11,586,483	$ 3,806,526	48.93%
9	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)	$ 1,645	$ 1,886	$ 241	14.64%
10	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)	$ 19,521,819	$ 26,793,339	$ 7,271,520	37.25%
11	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)	$ 57,141	$ 69,191	$ 12,051	21.09%
12	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)	$ 6,204	$ 8,555	$ 2,351	37.90%
13	Total General Service:	$ 27,366,763	$ 38,459,453	$ 11,092,690	40.53%
14	**[PROTECTED DATA BEGINS...**				
15					
16					
18					
21					
22					
23					
17					
19					
20				**...PROTECTED DATA ENDS]**	
24	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)	$ 26,273	$ 35,807	$ 9,534	36.29%
25	11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)	$ 30,252	$ 50,170	$ 19,917	65.84%
26	Total Irrigation:	$ 56,524	$ 85,977	$ 29,451	52.10%
27					
28	11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)	$ 95,933	$ 105,968	$ 10,035	10.46%
29	11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)	$ 97,067	$ 107,220	$ 10,153	10.46%
30	11.03 Outdoor Lighting - Signal (Rate 744)	$ 41,803	$ 46,176	$ 4,373	10.46%
31	11.04 Outdoor Lighting - Street & Area Lighting (Rate 741, 743)	$ 900,453	$ 980,941	$ 80,488	8.94%
32	11.07 LED STREET and AREA LIGHTING – DUSK TO DAWN (Rate 730, 731)	$ 1,457,801	$ 1,624,072	$ 166,270	11.41%
33	Total Lighting:	$ 2,593,058	$ 2,864,377	$ 271,319	10.46%
34					
35	11.05 Municipal Pumping - Secondary Service (Rate 872)	$ 818,301	$ 1,239,306	$ 421,005	51.45%
36	11.06 Civil Defense - Fire Sirens (Rate 843)	$ 2,553	$ 3,854	$ 1,301	50.98%
37	Total Other Public Authority:	$ 820,854	$ 1,243,160	$ 422,306	51.45%
38					
39	14.01 Water Heating - Controlled Service (Rate 191)	$ 688,841	$ 995,327	$ 306,486	44.49%
46	14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)	$ 601,122	$ 664,395	$ 63,273	10.53%
40	Total Water Heating:	$ 1,289,964	$ 1,659,722	$ 369,759	28.66%
41					
42	14.04 Controlled Service - Interruptible Load Rider CT Metering (Rates 170, 165, 881, 168, 268, 169, 269)	$ 1,154,187	$ 1,528,164	$ 373,977	32.40%
43	14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)	$ 2,851,749	$ 3,775,768	$ 924,019	32.40%
44	Total Interruptible:	$ 4,005,936	$ 5,303,932	$ 1,297,996	32.40%
45					
47	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)	$ 164,901	$ 185,740	$ 20,839	12.64%
48	14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)	$ 114,268	$ 123,667	$ 9,399	8.23%
49	Total Deferred Load:	$ 279,169	$ 309,407	$ 30,239	10.83%
50					
51	TOTAL REVENUE:	$ 114,030,799	$ 159,556,558	$ 45,525,760	39.92%

Proposed Test Year 2024 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
1													
2	**9.01 Residential Service (Rate 101)**												
3	Customer Charge	Bills			508,896	$14.00	$14.00	$17.00	$17.00	$ 7,124,544	$ 8,651,232	$ 1,526,688	
4	Seasonal Fixed Charge	Bills			6.1	$56.00	$56.00	$68.00	$68.00	$ 344	$ 417	$ 74	
5	Energy	kWh	119,796,914	282,520,800	402,317,714	$0.08050	$0.05446	$0.07911	$0.08980	$ 25,029,734	$ 34,847,942	$ 9,818,208	
6	Facilities Charge	Bills			508,896	$0.00	$0.00	$3.50	$3.50		$ 1,781,136	$ 1,781,136	
7	Revenue Adjustment:									$ (1,157)		$ 1,157	
8	Base Revenue:									$ 32,153,465	$ 45,280,727	$ 13,127,262	
9	Water Heating Control Credit 14.01 (Rate 192)	Bills			3,416	-$8.00	-$8.00	-$8.00	-$8.00	$ (27,326)	$ (27,326)	$ -	
10	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			2,139	-$8.25		-$8.00	-$8.00	$ (17,651)	$ (17,651)	$ -	
11	TailWinds Program 14.09	kWh			2,048	$3.73	$3.73	$3.73	$3.73	$ 7,643	$ 7,643	$ -	
12	WAPA Bill Credit 14.10									$ (69,391)	$ (69,391)	$ -	
13	WAPA, A/C, W/H, & Tailwinds									$ (106,726)	$ (106,726)	$ -	
14													
15	**9.02 Residential Demand Control (Rate 241)**												
16	Customer Charge	Bills			39,268	$20.10	$20.10	$21.00	$21.00	$ 789,287	$ 824,628	$ 35,341	
17	Facilities Charge	Bills			39,268	$0.00	$0.00	$7.00	$7.00	$ -	$ 274,876	$ 274,876	
18	Energy - All kWh	kWh	13,881,352	63,418,529	77,299,881	$0.03379	$0.03461	$0.07911	$0.05519	$ 2,663,966	$ 4,598,101	$ 1,934,135	
19	All kW, ratcheted	kW	50,835	115,080	165,915	$8.00	$8.00	$0.00	$11.00	$ 1,327,319	$ 1,265,881	$ (61,439)	
20	Revenue Adjustment:												
21	Base Revenue:									$ 4,780,572	$ 6,963,486	$ 2,182,914	
22	**Adjustments for Riders included in Base Rates**												
23	Renewable Resource Recovery Rider with CWIP Adjustment									$ 2,312,457	$ (3,096,518)	$ (5,408,974)	
24	Transmission Cost Recovery Rider with CWIP Adjustment									$ 2,796,469	$ 1,577,539	$ (1,218,930)	
25	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 1,229,408	$ 1,027,069	$ (202,339)	
26	Generation Cost Recovery Rider									$ 1,164,625	$ -	$ (1,164,625)	
27	Energy Adjustment Rider									$ 13,137,895	$ 13,833,443	$ 695,548	
28	PTC GAAP Provision									$ 1,355,886	$ 1,681,418	$ 325,532	
29	**Total Adjustments:**									$ 21,996,740.47	$ 15,022,952	$ (6,973,789)	
30													
31	**Total Base Revenue for the COSS Class:**									**$ 36,934,037**	**$ 52,137,488**	**$ 15,203,451**	**41.2%**
32	**Total Adjustments for the COSS Class:**									**$ 21,996,740**	**$ 15,022,952**	**$ (6,973,789)**	**-31.7%**
33	**Total for the COSS Class:**									**$ 58,824,052**	**$ 67,053,713**	**$ 8,229,662**	**14.0%**
34												0	
35	**9.03 Farm Service (Rate 361)**												
36	Customer Charge	Bills			11,015	$17.40	$17.40	$22.00	$22.00	$ 191,661	$ 242,330	$ 50,669	
37	Energy	kWh	7,298,479	21,730,504	29,028,983	$0.06793	$0.04595	$0.06527	$0.07409	$ 1,494,386	$ 2,086,311	$ 591,926	
38	Single Phase Facilities Charge	Bills			7,556	$10.00	$10.00	$20.00	$20.00	$ 75,563	$ 151,126	$ 75,563	
39	All Three Phase Facilities	Bills			3,459	$20.00	$20.00	$40.00	$40.00	$ 69,174	$ 138,348	$ 69,174	
40	Revenue Adjustment:									$ (11)		$ 11	
41	Base Revenue:									$ 1,830,773	$ 2,618,115	$ 787,343	
42	Water Heating Control Credit 14.01 (Rate 192)	Bills			12	-$8.00	-$8.00	-$8.00	-$8.00	$ (110)	$ (110)	$ -	
43	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			11	-$8.25		-$8.00		$ (146)	$ (146)	$ -	
44	TailWinds Program 14.09									$ 269	$ 269	$ -	
45	WAPA, A/C, W/H, & Tailwinds									$ 13	$ 13	$ -	
46	**Adjustments for Riders included in Base Rates**												
47	Renewable Resource Recovery Rider with CWIP Adjustment									$ 114,626	$ (153,376)	$ (268,002)	
48	Transmission Cost Recovery Rider with CWIP Adjustment									$ 169,257	$ 95,481	$ (73,776)	
49	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 53,237	$ 44,475	$ (8,762)	
50	Generation Cost Recovery Rider									$ 57,729	$ -	$ (57,729)	
51	Energy Adjustment Rider									$ 740,992	$ 771,233	$ 30,241	
52	PTC GAAP Provision									$ 67,210	$ 83,284	$ 16,074	
53	**Total Adjustments:**									$ 1,203,050	$ 841,096	$ (361,953)	
54													
55	**Total Base Revenue for the COSS Class:**									**$ 1,830,773**	**$ 2,618,128**	**$ 787,355**	**43.01%**
56	**Total Adjustments for the COSS Class:**									**$ 1,203,050**	**$ 841,096**	**$ (361,954)**	**-30.09%**
57	**Total for the COSS Class:**									**$ 3,033,835**	**$ 3,459,236**	**$ 425,401**	**14.02%**

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
58													
59													
60	**10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)**												
61	Customer Charge	Bills			106,726	$24.90	$24.90	$24.90	$24.90	$ 2,657,477	$ 2,657,477	$ -	
62	Energy	kWh	29,929,362	69,073,530	99,002,892	$0.06682	$0.04521	$0.07239	$0.08218	$ 5,122,480	$ 7,842,846	$ 2,720,366	
63	Facilities Charge	Bills			106,726	$0.00	$0.00	$12.00	$12.00		$ 1,280,712	$ 1,280,712	
64	Revenue Adjustment											$ -	
65	Base Revenue:									$ 7,779,957	$ 11,781,035	$ 4,001,078	
66	Water Heating Control Credit 14.01 (Rate 192)	Bills			277	-$8.00	-$8.00	-$8.00	-$8.00	$ (2,213)	$ (2,213)	$ -	
67	WAPA Bill Credit 14.10									$ (194,936)	$ (194,936)	$ -	
68	TailWinds Program 14.09				695	$3.73	$3.73	$3.73	$3.73	$ 2,596	$ 2,596	$ -	
69													
70	WAPA, A/C, W/H, & Tailwinds									$ (194,552)	$ (194,552)	$ -	
71													
72	**10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)**												
73	Customer Charge	Bills			45	$24.90	$24.90	$24.90	$24.90	$ 1,121	$ 1,121	$ -	
74	Energy	kWh	1,027	1,904	2,931	$0.06440	$0.04331	$0.07037	$0.08048	$ 149	$ 225	$ 77	
75	Facilities Charge	Bills			45	$0.00	$0.00	$12.00	$12.00	$ -	$ 540	$ 540	
76	Revenue Adjustment									$ (0)		$ 0	
77	Base Revenue:									1,269	1,886	$ 617	
78													
79	**10.01 Small General Service - Non-metered Service 1000 Watts or less Rate**												
80	Energy	kWh			5,632	$0.06681	$0.06681	$0.06681	$0.06681	$ 376	$ -		
81													
82	**10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)**												
83	Customer Charge	Bills			29,866	$31.90	$31.90	$54.00	$54.00	$ 952,725	$ 1,612,764	$ 660,039	
84	Energy	kWh	76,950,978	206,463,600	283,414,578	$0.07506	$0.05078	$0.05346	$0.06032	$ 16,259,127	$ 16,568,094	$ 308,967	
85	Demand per kW	kW	425,756	963,873	1,389,629	$0.00	$0.00	$2.24	$2.75	$ -	$ 3,604,344	$ 3,604,344	
86	Facilities Charge	kW			2,356,992	$0.98	$0.98	$2.12	$2.12	$ 2,303,849	$ 5,008,137	$ 2,704,288	
87	Revenue Adjustment									$ 6,118		$ (6,118)	
88	Base Revenue:									19,521,819	$ 26,793,339	t	
89													
90	**10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)**												
91	Customer Charge	Bills			72	$21.30	$21.30	$36.00	$36.00	$ 1,534	$ 2,592	$ 1,058	
92	Energy	kWh	272,272	680,225	952,497	$0.07233	$0.04865	$0.05216	$0.05852	$ 52,786	$ 54,009	$ 1,223	
93	Demand per kW	kW	823	1,772	2,595	$0.00	$0.00	$2.15	$2.62	$ -	$ 6,411	$ 6,411	
94	Facilities Charge	kW			4,340	$0.65	$0.65	$1.42	$1.42	$ 2,842	$ 6,178	$ 3,336	
95	Revenue Adjustment									$ (21)		$ 21	
96	Base Revenue:									57,141	69,191	$ 12,051	
97													

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
98	**10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)**												
99	Customer Charge	Bills			12	$219.00	$219.00	$219.00	$219.00	$ 2,628	$ 2,628	$ -	
100	Energy - Declared-Peak	kWh	299	481	780	$0.43264	$0.16259	$0.19539	$0.23215	$ 208	$ 31	$ (177)	
101	Energy - Intermediate	kWh	16,293	30,101	46,394	$0.02571	$0.02638	$0.03944	$0.03959	$ 1,213	$ 1,834	$ 621	
102	Energy - Off-Peak	kWh	11,244	21,066	32,310	$0.01702	$0.01845	$0.02573	$0.03407	$ 580	$ 1,007	$ 427	
103	Demand per kW - Declared-Peak	kW	-	-	-	N/A	N/A	N/A	N/A			$ -	
104	Demand per kW - Intermediate	kW	88	181	269	$3.44	$5.12	$2.57	$6.18	$ 1,229	$ 1,344	$ 115	
105	Demand per kW - Off-Peak	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -		$ -	
106	Facilities Charge	kW	263	542	805	$0.98	$0.98	$2.12	$2.12	$ 787	$ 1,711	$ 924	
107	Revenue Adjustment									$ (441)		$ 441	
108	Base Revenue:									6,204	8,555	$ 2,351	
109	**Adjustments for Riders included in Base Rates**												
110	Renewable Resource Recovery Rider with CWIP Adjustment									$ 1,713,445	$ (2,275,117)	$ (3,988,562)	
111	Transmission Cost Recovery Rider with CWIP Adjustment									$ 2,235,799	$ 1,261,255	$ (974,544)	
112	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 1,075,014	$ 898,086	$ (176,928)	
113	Generation Cost Recovery Rider									$ 862,945	$ -	$ (862,945)	
114	Energy Adjustment Rider									$ 10,328,623	$ 10,797,195	$ 468,572	
115	PTC GAAP Provision									$ 1,004,662	$ 1,235,395	$ 230,733	
116	**Total Adjustments:**									$ 17,220,488	$ 11,916,814	$ (5,303,674)	
117													
118	**Total Base Revenue for the COSS Class:**									**$ 27,366,763**	**$ 38,459,455**	**$ 11,092,692**	**40.53%**
119	**Total Adjustments for the COSS Class:**									**$ 17,220,488**	**$ 11,916,813**	**$ (5,303,675)**	**-30.80%**
120	**Total for the COSS Class:**									**$ 44,392,699**	**$ 50,181,716**	**$ 5,789,017**	**13.04%**
121													
122													
123	**10.04 Large General Service - Secondary Service (Rate 603)**											$ -	
124	Customer Charge	Bills			3,081	$215.90	$215.90	$215.90	$215.90	$ 665,188	$ 665,188	$ -	
125	Energy -All kWh	kWh	125,951,771	241,160,691	367,112,462	$0.02286	$0.02341	$0.03487	$0.04190	$ 8,525,572	$ 14,496,790	$ 5,971,218	
126	Demand per kW	kW	282,067	555,250	837,317	$10.75	$8.54	$11.78	$12.28	$ 7,774,050	$ 10,143,303	$ 2,369,253	
127	Facilities Charge <1,000 kW	kW	216,387	438,661	655,048	$0.76	$0.76	$0.75	$0.75	$ 495,198	$ 489,790	$ (5,407)	
128	Facilities Charge >=1,000 kW	kW	113,328	222,731	336,059	$0.56	$0.56	$0.52	$0.52	$ 189,305	$ 176,365	$ (12,940)	
129	Revenue Adjustment:									$ (190,981)		$ 190,981	
130	Base Revenue:									17,458,332	$ 25,971,436	$ 8,513,104	
131													
132	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			12	-$8.25	-$8.25	-$8.00	-$8.00	$ (99)	$ (99)	$ -	
133	TailWinds Program 14.09				230	$3.73	$3.73	$3.73	$3.73	$ 858	$ 858	$ -	
134	WAPA Bill Credit 14.10									$ (149,518)	$ (149,518)	$ -	
135	WAPA, A/C, W/H, & Tailwinds									$ (148,760)	$ (148,760)	$ -	
136													
137	**10.04 Large General Service - Primary Service (Rate 602)**												
138	Customer Charge	Bills			105	$282.00	$282.00	$282.00	$282.00	$ 29,610	$ 29,610	$ -	
139	Energy -All kWh	kWh	52,139,517	95,669,781	147,809,298	$0.02224	$0.02264	$0.03403	$0.04062	$ 3,325,547	$ 5,660,724	$ 2,335,178	
140	Demand per kW	kW	95,683	174,513	270,195	$10.35	$8.15	$11.29	$11.69	$ 2,412,595	$ 3,120,939	$ 708,344	
141	Facilities Charge - All kW	kW	109,652	179,172	288,823	$0.48	$0.48	$0.52	$0.52	$ 138,635	$ 151,576	$ 12,940	
142	Revenue Adjustment:									$ 21,861		$ (21,861)	
143	Base Revenue:									$ 5,928,247.00	$ 8,962,848.69	$ 3,034,601.69	
144													
145	**11.01 Standby Service - Option A: Firm - Transmission Service (Rates 941, 942, 943)**												
146	Customer Charge	Bills			12	$282.08	$282.08	$282.08	$282.08	$ 3,385	$ 3,385	$ -	
147	Facilities Charge per month per kW of Backup	kW			-	N/A	N/A	N/A	N/A	$ -		$ -	
148	Reservation Charge per kW of Contracted Backup	kW	1,800	3,600	5,400	$0.86830	$0.09424	$1.38999	$0.46669	$ 1,902	$ 4,182	$ 2,280	
149	Metered Demand per day per kW On-Peak Backup	kW	1,265	3,532	4,797	$0.43199	$0.29380	$0.49600	$0.17900	$ 1,584	$ 1,260	$ (324)	
150	Energy - On-Peak	kWh	10,685	24,130	34,815	$0.03213	$0.02775	$0.05568	$0.04935	$ 1,013	$ 1,786	$ 773	
151	Energy - Mid-Peak	kWh	20,331	25,531	45,862	$0.02465	$0.02494	$0.04552	$0.04518	$ 1,138	$ 2,079	$ 941	
152	Energy - Off-Peak	kWh	20,920	40,685	61,605	$0.01653	$0.01760	$0.02978	$0.03897	$ 1,062	$ 2,208	$ 1,147	
153	Revenue Adjustment				-					$ (67)		$ 67	
154	Base Revenue:									$ 10,017.00	$ 14,899.77	$ 4,882.77	
155													
156	**14.02 Real Time Pricing - Primary Service (Rate 662)**												
157	Customer Charge	Bills			12	$282.00	$282.00	$282.00	$282.00	$ 3,384	$ 3,384	$ -	
158	Energy - All kWh	kWh	12,179,176	31,691,222	43,870,398	Real Time Pricing		Real Time Pricing		$ 1,922,204	$ 1,922,204	$ -	
159	Base Revenue:									$ 1,925,588	$ 1,925,588	$ -	
160													

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
161	**10.04 Large General Service - Transmission Service (Rate 632)**												
162	Customer Charge	Bills			-	$282.00	$282.00	$282.00	$282.00	$ -		$ -	
163	Energy - All kWh	kWh			-	$0.02103	$0.02121	$0.03323	$0.03943	$ -		$ -	
164	Demand per kW	kW			-	$8.85	$7.30	$10.46	$5.76	$ -		$ -	
165	Facilities Charge	kW			-	N/A	N/A	N/A	N/A	$ -		$ -	
166	**Total Base Revenue:**									$ -		$ -	
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Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
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234	**11.01 Standby Service - Option A: Firm - Secondary Service (Rates 947, 948, 949)**												
235	Customer Charge	Bills			-	$242.24	$242.24	$215.90	$215.90				
236	Facilities Charge per month per kW of Contracted Backup	kW			-	$0.55	$0.55	$0.55	$0.55				
237	Reservation Charge per kW of Contracted Backup	kW			-	$0.97571	$0.10590	$1.60890	$1.26909				
238	Metered Demand per day per kW On-Peak Backup	kW			-	$0.57423	$0.41361	$0.60611	$0.45409				
239	Energy - On-Peak	kWh			-	$0.03527	$0.03090	$0.05867	$0.05264				
240	Energy - Mid-Peak	kWh			-	$0.02683	$0.02753	$0.04780	$0.04799				
241	Energy - Off-Peak	kWh			-	$0.01776	$0.01925	$0.03119	$0.04129				
242													
243	**11.01 Standby Service - Option A: Firm - Primary Service (Rates 944, 945, 946)**												
244	Customer Charge	Bills			-	$282.08	$282.08	$282.08	$282.08				
245	Facilities Charge per month per kW of Backup	kW			-	$0.45	$0.45	$0.45	$0.45				
246	Reservation Charge per kW of Contracted Backup	kW			-	$0.93395	$0.10136	$1.50014	$1.19059				
247	Metered Demand per day per kW On-Peak Backup	kW			-	$0.54988	$0.39227	$0.58599	$0.43394				
248	Energy - On-Peak	kWh			-	$0.03422	$0.02981	$0.05711	$0.05093				
249	Energy - Mid-Peak	kWh			-	$0.02612	$0.02665	$0.04663	$0.04653				
250	Energy - Off-Peak	kWh			-	$0.01738	$0.01871	$0.03048	$0.04010				
251													
252	**11.01 Standby Service - Option A: Firm - Transmission Service (Rates 941, 942, 943)**												
253	Customer Charge	Bills				$282.08	$282.08	$282.08	$282.08				
254	Facilities Charge per month per kW of Backup	kW				N/A	N/A	N/A	N/A				
255	Reservation Charge per kW of Contracted Backup	kW				$0.86830	$0.09424	$1.39874	$0.57174				
256	Metered Demand per day per kW On-Peak Backup	kW				$0.43199	$0.29380	$0.49600	$0.17900				
257	Energy - On-Peak	kWh				$0.03213	$0.02775	$0.05568	$0.04935				
258	Energy - Mid-Peak	kWh				$0.02465	$0.02494	$0.04552	$0.04518				
259	Energy - Off-Peak	kWh				$0.01653	$0.01760	$0.02978	$0.03897				
260													
261	**11.01 Standby Service - Option B: Non-Firm - Secondary Service (Rates 956, 957, 958)**												
262	Customer Charge	Bills			-	$242.24	$242.24	$215.90	$215.90				
263	Facilities Charge per month per kW of Backup	kW			-	$0.55	$0.55	$0.55	$0.55				
264	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A				
265	Energy - Mid-Peak	kWh			-	$0.02683	$0.02753	$0.04780	$0.04799				
266	Energy - Off-Peak	kWh			-	$0.01776	$0.01925	$0.03119	$0.04129				
267													
268	**11.01 Standby Service - Option B: Non-Firm - Primary Service (Rates 953, 954, 955)**												
269	Customer Charge	Bills			-	$282.08	$282.08	$282.08	$282.08				
270	Facilities Charge per month per kW of Backup	kW			-	$0.45	$0.45	$0.45	$0.45				
271	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A				
272	Energy - Mid-Peak	kWh			-	$0.02612	$0.02665	$0.04663	$0.04653				
273	Energy - Off-Peak	kWh			-	$0.01738	$0.01871	$0.03048	$0.04010				
274													
275	**11.01 Standby Service - Option B: Non-Firm - Transmission Service (Rates 950, 951, 952)**												
276	Customer Charge	Bills			-	$282.08	$282.08	$282.08	$282.08				
277	Facilities Charge per month per kW of Backup	kW			-	N/A	N/A	N/A	N/A				
278	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A				
279	Energy - Mid-Peak	kWh			-	$0.02465	$0.02494	$0.04552	$0.04518				
280	Energy - Off-Peak	kWh			-	$0.01653	$0.01760	$0.02978	$0.03897				
281													
282	**11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)**												
283	Customer Charge	Bills			57	$24.30	$24.30	$24.30	$24.30	$ 1,385	$ 1,385	$ -	
284	Energy	kWh	406,319	49,765	456,084	$0.04533	$0.02633	$0.06624	$0.04724	$ 19,730	$ 29,264	$ 9,534	
285	18% Return of Distribution Facilities				-					$ 5,158	$ 5,158	$ -	
286	Revenue Adjustment											$ -	
287	Base Revenue:									26,273	$ 35,807	$ 9,534	
288													

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
289	**11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)**												
290	Customer Charge	Bills			130	$24.30	$24.30	$24.30	$24.30	$ 3,159	$ 3,159	$ -	
291	Energy - Declared-Peak	kWh	12,789	290	13,079	$0.17685	$0.12867	$0.18683	$0.22632	$ 2,299	$ 808	$ (1,491)	
292	Energy - Intermediate	kWh	360,088	29,410	389,498	$0.03274	$0.03050	$0.06174	$0.06509	$ 12,686	$ 24,145	$ 11,459	
293	Energy - Off-Peak	kWh	450,273	35,640	485,913	$0.01420	$0.01457	$0.03369	$0.04748	$ 6,913	$ 16,861	$ 9,949	
294	Demand per kW - Declared-Peak	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -	$ -	$ -	
295	Demand per kW - Intermediate	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -	$ -	$ -	
296	Demand per kW - Off-Peak	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -	$ -	$ -	
297	18% Return of Distribution Facilities				-					$ 5,196	$ 5,196	$ -	
298	Revenue Adjustment											$ -	
299	Base Revenue:									30,252	50,170	$ 20,972	
300	**Adjustments for Riders included in Base Rates**												
301	Renewable Resource Recovery Rider with CWIP Adjustment									$ 3,539	$ (4,762)	$ (8,301)	
302	Transmission Cost Recovery Rider with CWIP Adjustment									$ 7,840	$ 4,423	$ (3,417)	
303	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 6,248	$ 5,220	$ (1,028)	
304	Generation Cost Recovery Rider									$ 1,782	$ -	$ (1,782)	
305	Energy Adjustment Rider									$ 30,398	$ 30,776	$ 377	
306	PTC GAAP Provision									$ 2,075	$ 2,586	$ 511	
307	**Total Adjustments:**									$ 51,883	$ 38,242	$ (13,641)	
308													
309	**Total Base Revenue for the COSS Class:**									**$ 56,525**	**$ 85,977**	**$ 29,452**	**52.10%**
310	**Total Adjustments for the COSS Class:**									**$ 51,883**	**$ 38,242**	**$ (13,641)**	**-26.29%**
311	**Total for the COSS Class:**									**$ 108,408**	**$ 124,219**	**$ 15,811**	**14.58%**
312													
313	**11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)**									$ 81,565			
314	Customer Charge	Bills			1,478	$2.00	$2.00	$2.00	$2.00	$ 2,955	$ 2,955	$ -	
315	Energy	kWh			1,220,905	$0.06681	$0.06681	$0.08437	$0.08437	$ 92,978	$ 103,012	$ 10,035	
316													
317	Base Revenue:									$ 95,933	$ 105,968	$ 10,035	10.46%
318													
319	**11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)**												
320		kWh			1,199,812	$0.00	$0.00	$0.00	$0.00	$ -	$ -		
321	Monthly charge for connected KW	kW			4,253	$ 22.83	$ 22.83	$25.21	$25.21	$ 97,067	$ 107,220	$ 10,153	
322													
323	Base Revenue:									$ 97,067	$ 107,220	$ 10,153	10.46%
324													
325	**11.03 Sign Lighting (Rate 744)**												
326	Monthly charge for connected KW	kW			1,831	$22.83	$22.83	$25.21	$25.21	$ 41,803	$ 46,176	$ 4,373	
327	Energy	kWh			150,773					$ -	$ -	$ -	
328	Base Revenue:									41,803	46,176	$ 4,373	10.46%
329													

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
330	**11.04 Outdoor Lighting - Street & Area Lighting (Rate 741)**												
331	Type:		**kWh/lt**	**Annual Kwh**	**Quantity**			Percent Increase:	11.44%				
332	MV-6	Lts	70		45,672	$7.12	$7.12	$7.94	$7.94	$ 325,265	$ 362,478		
333	MV-6PT	Lts	70		824	$10.16	$10.16	$11.32	$11.32	$ 8,371	$ 9,329		
334	MV-11	Lts	100		59	$12.90	$12.90	$14.38	$14.38	$ 761	$ 848		
335	MV-21	Lts	154		244	$16.99	$16.99	$18.93	$18.93	$ 4,145	$ 4,619		
336	MV-35	Lts	260	-		$24.92	$24.92	$27.77	$27.77	$ -	$ -		
337	MV-55	Lts	366	-		$31.86	$31.86	$35.50	$35.50	$ -	$ -		
338	MA-8	Lts	41		838	$8.59	$8.59	$9.58	$9.58	$ 7,202	$ 8,027		
339	MA-14	Lts	70		12	$16.36	$16.36	$18.23	$18.23	$ 196	$ 219		
340	MA-20	Lts	98	-		$18.67	$18.67	$20.81	$20.81	$ -	$ -		
341	MA-36	Lts	156		180	$18.29	$18.29	$20.38	$20.38	$ 3,292	$ 3,668		
342	MA-110	Lts	369		180	$39.02	$39.02	$43.49	$43.49	$ 7,024	$ 7,828		
343	HPS-9	Lts	44		27,229	$7.64	$7.64	$8.51	$8.51	$ 208,026	$ 231,826		
344	HPS-9PT	Lts	44		2,028	$9.87	$9.87	$11.00	$11.00	$ 20,026	$ 22,318		
345	HPS-14	Lts	64		1,171	$11.90	$11.90	$13.26	$13.26	$ 13,931	$ 15,525		
346	HPS-14PT	Lts	64		996	$12.73	$12.73	$14.19	$14.19	$ 12,679	$ 14,129		
347	HPS-19	Lts	83		154	$13.83	$13.83	$15.41	$15.41	$ 2,129	$ 2,373		
348	HPS-23	Lts	102		2,167	$15.65	$15.65	$17.44	$17.44	$ 33,904	$ 37,783		
349	HPS-44	Lts	156		1,576	$19.31	$19.31	$21.52	$21.52	$ 30,437	$ 33,920		
350	UHPS23	Lts	102		12	$18.11	$18.11	$20.18	$20.18	$ 217	$ 242		
351	UMV6	Lts	70		48	$9.58	$9.58	$10.68	$10.68	$ 460	$ 513		
352	**Seasonal Charge**				92	$32.79	$32.79	$36.55	$36.55	$ 3,017	$ 3,362		
353	**11.04 Outdoor Lighting - Flood Lighting (Rate 743)**												
354	Type:		kWh/lt	Annual Kwh	Quantity								
355	400MV-F	Lts	154		721	$17.35	$17.35	$19.33	$19.33	$ 12,509	$ 13,941		
356	400MA-F	Lts	156		1,883	$18.78	$18.78	$20.93	$20.93	$ 35,363	$ 39,409		
357	400HPS-F	Lts	156		4,680	$19.20	$19.20	$21.40	$21.40	$ 89,856	$ 100,136		
358	1000MV-F	Lts	366	-		$30.93	$30.93	$34.47	$34.47	$ -	$ -		
359	1000MA-F	Lts	308		1,883	$32.62	$32.62	$36.35	$36.35	$ 61,423	$ 68,451		
360	**UNDERGROUND SERVICE:**					$2.46	$2.46	$2.74	$2.74	$ -	$ -		
361	Revenue Adjustment:									$ 20,218			
362	Base Revenue:			8,237,849						900,453	$ 980,941	$ 80,488	
363													
364	**11.07 LED STREET and AREA LIGHTING – DUSK TO DAWN**			Future kWh Allocation									
365	Type:		kWh/lt	Annual Kwh	Quantity			Percent Increase:	11.44%				
366	**LED5**	Lts	16		116,839	$7.44	$7.44	$8.29	$8.29	$ 869,282	$ 968,735		
367	**LED8**	Lts	26		1046	$13.88	$13.88	$15.47	$15.47	$ 14,518	$ 16,180		
368	**LED3PT**	Lts	9		2536	$10.01	$10.01	$11.16	$11.16	$ 25,385	$ 28,290		
369	**LED5PT**	Lts	16		1608	$12.75	$12.75	$14.21	$14.21	$ 20,502	$ 22,848		
370	**LED10**	Lts	32		6184	$15.71	$15.71	$17.51	$17.51	$ 97,151	$ 108,265		
371	**LED13**	Lts	45		3441	$20.66	$20.66	$23.02	$23.02	$ 71,091	$ 79,224		
372	**LED20 - Flood**	Lts	68		13,493	$18.98	$18.98	$21.15	$21.15	$ 256,097	$ 285,397		
373	**LED30 - Flood**	Lts	89		3337	$30.96	$30.96	$34.50	$34.50	$ 103,314	$ 115,133		
374										$ 101,198			
375				2,025,558	-	$0.00	$0.00			1,558,539	1,624,072	$ 66,018	
376													
377	**PLED5**	Lts	16			$6.95	$6.95	$7.75	$7.75				
378	**PLED8**	Lts	26			$13.08	$13.08	$14.58	$14.58				
379	**PLED3PT**	Lts	9			$9.74	$9.74	$10.85	$10.85				
380	**PLED5PT**	Lts	16			$12.26	$12.26	$13.66	$13.66				
381	**PLED10**	Lts	32			$14.71	$14.71	$16.39	$16.39				
382	**PLED13**	Lts	45			$19.26	$19.26	$21.46	$21.46				
383	**PLED20 - Flood**	Lts	68			$16.89	$16.89	$18.82	$18.82				
384	**PLED30 - Flood**	Lts	89			$28.21	$28.21	$31.44	$31.44				
385													
386	**Seasonal Charge**					$32.79	$32.79	$36.55	$36.55				
387	**UNDERGROUND SERVICE:**					$2.46	$2.46	$2.74	$2.74				
388	**UNDERGROUND SERVICE SUPPLIED BY THE COMPANYover 200Ft**					$0.11	$0.11	$0.12	$0.12				
389													
390	**ALUMINUM ALLOY POLES, Additional Monthly Charge**												
391	**STANDARDS 30'**	ea				$11.67	$11.67	$26.61	$26.61				
392	**STANDARDS 40'**	ea				$10.87	$10.87	$27.94	$27.94				
393													
394	**LED FLOOD VISOR, Additional Monthly Charge**												
395	**Lighting Visor LED 20-Flood**	ea				$0.76	$0.76	$0.85	$0.85				
396	**Lighting Visor LED 30-Flood**	ea				$1.38	$1.38	$1.54	$1.54				
397													
398	**DECORATIVE LIGHTS**		Appx Wattage										
399	**DLEDA7 (Arlington)**	Lts	66			$87.77	$87.77	$97.81	$97.81				
400	**DLEDG7 (Granville)**	Lts	68			$86.11	$86.11	$95.96	$95.96				
401	**DLEDE17 (Esplanade)**	Lts	170			$110.56	$110.56	$123.21	$123.21				
402	**Lighting & Irrigation RevenueCorrections**									$ (100,737)			
403	**Adjustments for Riders included in Base Rates**												
404	Renewable Resource Recovery Rider with CWIP Adjustment	kWh								$ 162,353	$ (182,252)	$ (344,604)	
405	Transmission Cost Recovery Rider with CWIP Adjustment	%								$ 74,484	$ 19,224	$ (55,260)	
406	Advanced Meter & Distribution Technology Rider with CWIP adjustn	kWh								$ 377,958	$ 315,753	$ (62,205)	
407	Generation Cost Recovery Rider	kWh								$ 81,766	$ -	$ (81,766)	
408	Energy Adjustment Rider	kWh								$ 262,779	$ 307,739	$ 44,960	
409	PTC GAAP Provision									$ 95,194	$ 98,963	$ 3,769	
410	**Total Adjustments:**									$ 1,054,533	$ 559,427	$ (495,106)	

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
411													
412	**Total Base Revenue for the COSS Class:**							**$ 2,864,376.55**	**$ 2,864,376.55**	**$ 2,593,058**	**$ 2,864,377**	**$ 271,319**	**10.46%**
413	**Total Adjustments for the COSS Class:**									**$ 1,054,534**	**$ 559,428**	**$ (495,106)**	**-46.95%**
414	**Total for the COSS Class:**									**$ 3,647,592**	**$ 3,423,805**	**$ (223,787)**	**-6.14%**
415													
416	**11.05 Municipal Pumping - Secondary Service (Rate 872)**												
417	Customer Charge	Bills			6,441	$26.50	$26.50	$33.45	$33.45	$ 170,687	$ 215,451	$ 44,765	
418	Facilities Charge (Changing per Month to per KW)	kW			80,026	$0.65	$0.65	$2.12	$2.12	$ 52,017	$ 169,655	$ 117,638	
419	Energy - All kWh	kWh	6,177,157	11,768,013	17,945,170	$0.04599	$0.03111	$0.04373	$0.04963	$ 650,190	$ 854,200	$ 204,010	
420	Revenue Adjustment:									$ (54,592)		$ 54,592	
421	Base Revenue:									818,301	1,239,306	$ 421,005	
422													
423	**11.05 Municipal Pumping -Primary Service (Rate 874)**												
424	Customer Charge	Bills			-	$26.50	$26.50	$33.45	$33.45	$ -		$ -	
425	Facilities Charge (Changing per Month to per KW)	KW			-	$0.65	$0.65	$1.42	$1.42	$ -		$ -	
426	Energy - All kWh	kWh			-	$0.04432	$0.02981	$0.04250	$0.04861	$ -		$ -	
427	Base Revenue:									$ -		$ -	
428													
429	**11.06 Civil Defense - Fire Sirens (Rate 843)**												
430	Customer Charge	Bills			624	$1.22	$1.22	$1.22	$1.22	$ 761	$ 761	$ -	
431	Load Charge	HP			4,170	$0.42962	$0.42962	$0.74170	$0.74170	$ 1,792	$ 3,093	$ 1,301	
432	Base Revenue:									2,553	3,854	$ 1,301	
433	**Adjustments for Riders included in Base Rates**												
434	Renewable Resource Recovery Rider with CWIP Adjustment									$ 51,394	$ (69,288)	$ (120,682)	
435	Transmission Cost Recovery Rider with CWIP Adjustment									$ 104,632	$ 59,025	$ (45,607)	
436	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 36,248	$ 30,282	$ (5,966)	
437	Generation Cost Recovery Rider									$ 25,884	$ -	$ (25,884)	
438	Energy Adjustment Rider									$ 474,092	$ 483,367	$ 9,275	
439	PTC GAAP Provision									$ 30,134	$ 37,624	$ 7,489	
440	**Total Adjustments:**									$ 722,384	$ 541,010	$ (181,374)	
441													
442	**Total Base Revenue for the COSS Class:**									**$ 820,854**	**$ 1,243,160**	**$ 422,306**	**51.45%**
443	**Total Adjustments for the COSS Class:**									**$ 722,384**	**$ 541,010**	**$ (181,374)**	**-25.11%**
444	**Total for the COSS Class:**									**$ 1,543,238**	**$ 1,784,170**	**$ 240,932**	**15.61%**
445													
446	**14.01 Water Heating - Controlled Service (Rate 191)**												
447	Customer Charge	Bills			59,233	$4.00	$4.00	$5.00	$5.00	$ 236,932	$ 296,165	$ 59,233	
448	Facilities Charges per Month	Bills			59,233	$2.00	$2.00	$2.00	$2.00	$ 118,466	$ 118,466	$ -	
449	Energy - All kWh	kWh	3,376,056	8,626,096	12,002,152	$0.03078	$0.02661	$0.04717	$0.04886	$ 333,443	$ 580,696	$ 247,253	
450	Revenue Adjustment:									$ 0		$ (0)	
451	Base Revenue:									688,841	995,327	$ 306,486	
452													
453	**14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)**												
454	Customer Charge	Bills			8,150	$8.80	$8.80	$10.00	$10.00	$ 71,720	$ 81,500	$ 9,780	
455	Facilities Charge	Bills			8,150	$11.60	$11.60	$11.60	$11.60	$ 94,540	$ 94,540	$ -	
456	Energy - All kWh	kWh	1,226,209	16,997,324	18,223,533	$0.02602	$0.02371	$0.03564	$0.02616	$ 434,849	$ 488,355	$ 53,506	
457	Penalty kWh	kWh			-	$0.35916	$0.16537	$0.17726	$0.18221	$ -		$ -	
458	Revenue Adjustment:									$ 13		$ (13)	
459	Base Revenue:									601,122	664,395	$ 63,273	
460													
461	**Adjustments for Riders included in Base Rates**												
462	Renewable Resource Recovery Rider with CWIP Adjustment									$ 80,765	$ (93,030)	$ (173,795)	
463	Transmission Cost Recovery Rider with CWIP Adjustment									$ 26,916	$ -	$ (26,916)	
464	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 333,025	$ 278,215	$ (54,810)	
465	Generation Cost Recovery Rider									$ 40,676	$ -	$ (40,676)	
466	Energy Adjustment Rider									$ 860,771	$ 805,545	$ (55,226)	
467	PTC GAAP Provision									$ 47,356	$ 50,516	$ 3,160	
468	**Total Adjustments:**									$ 1,389,510	$ 1,041,246	$ (348,264)	
469													
470	**Total Base Revenue for the COSS Class:**									**$ 1,289,964**	**$ 1,659,723**	**$ 369,759**	**28.66%**
471	**Total Adjustments for the COSS Class:**									**$ 1,389,510**	**$ 1,041,246**	**$ (348,264)**	**-25.06%**
472	**Total for the COSS Class:**									**$ 2,679,474**	**$ 2,700,969**	**$ 21,495**	**0.80%**
473													
474	**14.02 Real Time Pricing - Secondary Service (Rate 664)**												
475	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
476	Consumption Change from CBL	kWh			-								
477	Conservation Improvement Program				-								
478													
479	**14.02 Real Time Pricing - Primary Service (Rate 662)**												
480	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
481	Consumption Change from CBL	kWh			-								
482	Conservation Improvement Program				-								
483													
484	**14.02 Real Time Pricing - Transmission Service (Rate 660)**												
485	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
486	Consumption Change from CBL	kWh			-								
487	Conservation Improvement Program				-								
488													
489	**14.03 Large General Service Rider**												
490	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
491	Fixed Rate Energy Pricing (FREP) Peak	kWh			-								
492	Fixed Rate Energy Pricing (FREP) Shoulder	kWh			-								
493	Fixed Rate Energy Pricing (FREP) Off-Peak	kWh			-								
494	Capacity Purchase	kW			-								
495													
496	**14.04 Controlled Service - Interruptible Load Rider CT Metering - Option 1 (Rates 170, 165, 881)**												
497	Customer Charge	Bills			2,619	$20.20	$20.20	$20.20	$20.20	$ 52,908	$ 52,908	$ -	
498	Facilities Charge	kW			558,708	$0.76	$0.76	$1.42	$1.42	$ 424,618	$ 793,365	$ 368,747	
499	Energy - All kWh	kWh	7,784,504	57,052,011	64,836,515	$0.01064	$0.01009	$0.01148	$0.00996	$ 658,207	$ 657,395	$ (812)	
500	Penalty kWh	kWh	69,359	806,935	876,294	$0.41350	$0.14322	$0.18412	$0.20847			$ -	
501	Revenue Adjustment:									$ 50		$ (50)	
502	Base Revenue:									1,135,783	1,503,669	$ 367,886	

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
503													
504	**14.04 Controlled Service - Interruptible Load Rider CT Metering - Option 2 (Rates 168, 268, 169, 269)**												
505	Customer Charge	Bills	40	82	122	$20.20	$20.20	$20.20	$20.20	$ 2,458	$ 2,458	$ -	
506	Facilities Charge	kW			9,301	$0.76	$0.76	$1.42	$1.42	$ 7,069	$ 13,175	$ 6,106	
507	Energy - All kWh	kWh	69,359	806,935	876,294	$0.01064	$0.01009	$0.01148	$0.00996	$ 8,876	$ 8,830	$ (46)	
508	Control Period Demand	kW			-	$11.30	$8.49	$11.78	$12.28	$ -		$ -	
509	Revenue Adjustment:									$ 1	$ 32	$ 31	
510	Base Revenue:									18,404	24,495	$ 6,091	
511													
512	**14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)**												
513	Customer Charge	Bills			85,305	$8.50	$8.50	$8.50	$8.50	$ 725,093	$ 725,093	$ -	
514	Facilities Charge	Bills			85,305	$11.70	$11.70	$11.70	$11.70	$ 998,069	$ 998,069	$ -	
515	Energy - All kWh	kWh	12,491,661	119,327,289	131,818,950	$0.00911	$0.00850	$0.01770	$0.01535	$ 1,128,706	$ 2,052,607	$ 923,901	
516	Penalty kWh	kWh	-	-	-	$0.41350	$0.17038	$0.18412	$0.20847	$ -		$ -	
517	Revenue Adjustment:									$ (118)		$ 118	
518	Base Revenue:									2,851,749	3,775,768	$ 924,019	
519	**Adjustments for Riders included in Base Rates**												
520	Renewable Resource Recovery Rider with CWIP Adjustment									$ 250,813	$ (279,508)	$ (530,321)	
521	Transmission Cost Recovery Rider with CWIP Adjustment									$ 175,904	$ -	$ (175,904)	
522	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 484,981	$ 405,162	$ (79,819)	
523	Generation Cost Recovery Rider									$ 126,317	$ -	$ (126,317)	
524	Energy Adjustment Rider									$ 5,732,433	$ 5,428,166	$ (304,267)	
525	PTC GAAP Provision									$ 147,062	$ 151,774	$ 4,712	
526	**Total Adjustments:**									$ 6,917,512	$ 5,705,594	$ (1,211,917)	
527													
528													
529	**Total Base Revenue for the COSS Class:**									**$ 4,005,936**	**$ 5,303,932**	**$ 1,297,996**	**32.40%**
530	**Total Adjustments for the COSS Class:**									**$ 6,917,512**	**$ 5,705,594**	**$ (1,211,917)**	**-17.52%**
531	**Total for the COSS Class:**									**$ 10,923,448**	**$ 11,009,526**	**$ 86,079**	**0.79%**
532													
533	**14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)**												
534	Customer Charge	Bills			3,120	$6.70	$6.70	$10.00	$10.00	$ 20,905	$ 31,202	$ 10,297	
535	Facilities Charge	Bills			3,120	$6.00	$6.00	$6.00	$6.00	$ 18,721	$ 18,721	$ -	
536	Energy - All kWh	kWh	232,020	7,663,639	7,895,659	$0.01439	$0.01591	$0.01315	$0.01732	$ 125,278	$ 135,816	$ 10,537	
537	Penalty kWh	kWh				$0.06736	$0.04602	$0.07432	$0.07601	$ (4)		$ 4	
538	Base Revenue:									$ 164,901	$ 185,739	$ 20,838	
539													
540	**14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)**												
541	Customer Charge	Bills			519	$6.70	$6.70	$10.00	$10.00	$ 3,477	$ 5,190	$ 1,713	
542	Facilities Charge	Bills			519	$38.00	$38.00	$38.00	$38.00	$ 19,722	$ 19,722	$ -	
543	Energy - All kWh	kWh	159,031	5,579,743	5,738,774	$0.01439	$0.01591	$0.01315	$0.01732	$ 91,070	$ 98,755	$ 7,684	
544	Penalty kWh	kWh				$0.06736	$0.04602	$0.07432	$0.07601	$ (2)		$ 2	
545	Base Revenue:									$ 114,268	$ 123,667	$ 9,399	
546													

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
547	**14.07 Fixed Time of Service Rider - Primary CT Metering (Rates 303, 886)**												
548	Customer Charge	Bills			-	$6.70	$6.70	$10.00	$10.00				
549	Facilities Charge	Bills			-	$18.00	$18.00	$18.00	$18.00				
550	Energy - All kWh	kWh			-	$0.01433	$0.01585	$0.01309	$0.01726				
551	Penalty kWh	kWh			-	$0.06736	$0.04602	$0.07432	$0.07601				
552													
553	**Adjustments for Riders included in Base Rates**												
554	Renewable Resource Recovery Rider with CWIP Adjustment									$ 17,479	$ (19,558)	$ (37,037)	
555	Transmission Cost Recovery Rider with CWIP Adjustment									$ 12,142	$ -	$ (12,142)	
556	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 22,418	$ 18,728	$ (3,690)	
557	Generation Cost Recovery Rider									$ 8,803	$ -	$ (8,803)	
558	Energy Adjustment Rider									$ 373,888	$ 412,667	$ 38,779	
559										$ 10,249	$ 10,620	$ 371	
560	**Total Adjustments:**									$ 444,979	$ 422,458	$ (22,521)	
561													
562													
563	**Total Base Revenue for the COSS Class:**									**$ 279,169**	**$ 309,406**	**$ 30,237**	**10.83%**
564	**Total Adjustments for the COSS Class:**									**$ 444,979**	**$ 422,458**	**$ (22,521)**	**-5.06%**
565	**Total for the COSS Class:**									**$ 724,148**	**$ 731,864**	**$ 7,715**	**1.07%**
566													
567													
568													
569	**Total Base Revenue:**									**$ 114,030,799**	**$ 159,556,559**	**$ 45,525,760**	**39.92%**
570	**Total Adjustments:**									**$ 92,511,010**	**$ 69,447,741**	**$ (23,063,269)**	**-24.93%**
571	**TOTAL :**									**$ 206,091,785**	**$ 228,554,279**	**$ 22,462,494**	**10.90%**
572													

Otter Tail Power Company
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Rate Base		695,424,815	215,995,994	11,399,807	155,262,442	237,067,236	612,155	14,072,417	6,423,958	16,470,066	37,083,723	1,037,017
3	Total Available for Return		19,989,879	1,821,704	306,981	4,956,795	10,384,769	(9,410)	1,330,747	(86,935)	(300,417)	1,358,370	227,275
5	Rate of Return Earned		2.87%	0.84%	2.69%	3.19%	4.38%	-1.54%	9.46%	-1.35%	-1.82%	3.66%	21.92%
7	Rate of Return Requested		7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%
9	Operating Income Required		54,590,848	16,955,686	894,885	12,188,102	18,609,778	48,054	1,104,685	504,281	1,292,900	2,911,072	81,406
11	Total Available for Return		19,989,879	1,821,704	306,981	4,956,795	10,384,769	(9,410)	1,330,747	(86,935)	(300,417)	1,358,370	227,275
13	Operating Income Defeciency		34,600,969	15,133,982	587,904	7,231,307	8,225,009	57,464	(226,062)	591,215	1,593,318	1,552,702	(145,869)
15	Incremental Taxes		11,170,475	4,885,810	189,797	2,334,534	2,655,338	18,552	(72,981)	190,866	514,382	501,270	(47,092)
17	Revenue Increase (Decrease) Required		45,771,444	20,019,792	777,701	9,565,841	10,880,346	76,016	(299,044)	782,081	2,107,700	2,053,972	(192,961)
19	Percentage Increase		25.04%	39.31%	29.46%	24.84%	14.97%	80.81%	-9.78%	57.55%	88.49%	19.73%	-26.73%

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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Electric Plant in Service		1,251,434,481	385,102,135	20,453,037	278,137,810	432,958,644	1,096,035	25,210,308	11,549,052	29,505,178	65,631,848	1,790,433
3	Accumulated Depreciation		(461,390,298)	(139,804,458)	(7,524,247)	(101,737,617)	(163,077,087)	(406,330)	(9,362,970)	(4,250,659)	(10,955,888)	(23,666,655)	(604,387)
5	Net Plant Excluding Big Stone Plant Capitalized Items		790,044,183	245,297,677	12,928,790	176,400,193	269,881,558	689,705	15,847,338	7,298,393	18,549,290	41,965,193	1,186,046
7	Net Capitalized Items - Big Stone Plant		0	0	0	0	0	0	0	0	0	0	0
9	Net Electric Plant in Service		790,044,183	245,297,677	12,928,790	176,400,193	269,881,558	689,705	15,847,338	7,298,393	18,549,290	41,965,193	1,186,046
11	Plant Held for Future Use		4,921	1,858	89	1,303	1,214	4	104	51	105	191	2
13	Construction Work in Progress		780,993	295,907	15,995	176,537	130,066	1,536	35,090	7,222	41,619	76,059	961
15	Materials and Supplies		14,737,429	5,004,343	275,793	3,346,211	3,724,423	21,454	500,458	135,840	583,584	1,126,623	18,698
17	Fuel Stocks		4,495,117	1,008,740	59,040	967,135	2,409,739	0	7,036	42,194	784	0	448
19	Prepayments		18,607,498	5,777,368	304,505	4,154,662	6,356,379	16,244	373,244	171,895	436,882	988,384	27,934
21	Customer Advances		(709,884)	(220,409)	(11,617)	(158,502)	(242,499)	(620)	(14,239)	(6,558)	(16,667)	(37,707)	(1,066)
23	Cash Working Capital		1,531,800	456,514	21,174	309,290	604,143	871	12,613	13,428	22,207	86,300	5,260
25	Accumulated Deferred Income Taxes		(134,067,241)	(41,626,005)	(2,193,962)	(29,934,386)	(45,797,788)	(117,040)	(2,689,228)	(1,238,507)	(3,147,738)	(7,121,320)	(201,267)
27	Unamortized CIP Tracker		0	0	0	0	0	0	0	0	0	0	0
29	Unamortized Rate Case Expense		0	0	0	0	0	0	0	0	0	0	0
32	**Total Average Rate Base**		695,424,815	215,995,994	11,399,807	155,262,442	237,067,236	612,155	14,072,417	6,423,958	16,470,066	37,083,723	1,037,017

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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	**Plant in Service**												
2	Production Plant												
3	A/C 101 & 106 - Direct Assigned												
4													
5	A/C 101 & 106 - Base Demand	E1-E8760	268,586,859	49,589,020	3,314,914	52,900,572	160,063,013	0	214,936	2,412,010	58,777	0	33,618
6	Peak Demand	D1	159,416,909	60,673,667	2,589,637	45,687,080	47,987,360	0	728,441	1,750,725	0	0	0
7	Base Energy	E2-E8760	205,609,759	41,287,240	2,338,155	32,496,271	106,878,616	102,509	939,988	1,477,642	2,485,623	16,455,376	1,148,339
8													
9	**Subtotal A/C 101 & 106**		633,613,528	151,549,927	8,242,707	131,083,923	314,928,989	102,509	1,883,364	5,640,377	2,544,400	16,455,376	1,181,956
10													
11	A/C 114 - Base Demand	E1-E8760	529,381	97,739	6,534	104,266	315,482	0	424	4,754	116	0	66
12	Peak Demand	D1	150,697	57,355	2,448	43,188	45,363	0	689	1,655	0	0	0
13	Base Energy	E2-E8760	0	0	0	0	0	0	0	0	0	0	0
14													
15	**Subtotal A/C 114**		680,078	155,094	8,982	147,454	360,845	0	1,112	6,409	116	0	66
16													
17	**Total Production Plant**	P10	634,293,606	151,705,021	8,251,688	131,231,377	315,289,834	102,509	1,884,476	5,646,786	2,544,516	16,455,376	1,182,023
18													
19													
20	Transmission Plant												
21	A/C 101 & 106	D2	215,798,006	82,132,167	3,505,516	61,845,263	64,959,085	0	986,069	2,369,905	0	0	0
22	A/C 101 & 106 (Direct FERC)												
23	A/C 114	D2	22,846	8,695	371	6,547	6,877	0	104	251	0	0	0
24													
25	**Total Transmission Plant**		215,820,851	82,140,862	3,505,887	61,851,811	64,965,962	0	986,173	2,370,156	0	0	0
26													
27													
28	Distribution Plant												
29	Primary Demand	D3	118,538,756	26,970,201	3,011,054	25,435,194	25,741,657	486,629	1,414,396	971,163	10,653,464	23,854,997	0
30	Secondary Demand	D4	69,647,623	15,834,999	2,357,118	15,451,793	8,635,356	339,122	562,606	656,523	10,316,784	15,493,321	0
31	Primary Customer	C2	52,084,671	40,186,989	893,374	10,084,735	227,928	26,199	106,541	515,240	12,226	30,565	873
32	Secondary Customer	C3	38,091,927	29,395,531	653,475	7,372,198	164,806	19,163	77,932	376,882	8,943	22,357	639
33	Streetlighting	C4	10,226,986	0	0	0	0	0	10,226,986	0	0	0	0
34	Area Lighting	C5	8,488,723	0	0	0	0	0	8,488,723	0	0	0	0
35	Meters	C6	28,784,055	8,809,477	583,492	10,420,252	629,403	48,264	81,988	292,195	2,887,116	4,540,120	491,747
36	Load Management	C9	3,888,421	833,095	3,863	7,297	215	4,507	215	0	1,315,526	1,695,806	27,899
37													
38	**Total Distribution Plant**	P60	329,751,161	122,030,291	7,502,377	68,771,469	35,399,364	923,884	20,959,387	2,812,003	25,194,060	45,637,166	521,158
39													
40													
41	General Plant												
42	Production	P10	17,997,940	4,304,596	234,140	3,723,661	8,946,279	2,909	53,472	160,226	72,200	466,918	33,540
43	Transmission	D2	7,801,293	2,969,152	126,728	2,235,762	2,348,329	0	35,647	85,674	0	0	0
44	Distribution	P60	14,159,489	5,239,971	322,151	2,953,041	1,520,046	39,672	899,994	120,747	1,081,831	1,959,656	22,378
45	Customer Accounts	OXC	10,761,420	7,301,448	162,437	2,728,782	61,335	7,940	33,553	144,840	136,538	176,047	8,502
46	Customer Service & Info	OXI	2,508,909	1,935,599	43,033	485,645	10,937	1,262	5,300	24,819	589	1,683	42
47	Load Management	C9	72,521	15,538	72	136	4	84	4	0	24,535	31,628	520
48													
49	**Total General Plant**	P90	53,301,572	21,766,304	888,560	12,127,028	12,886,930	51,866	1,027,970	536,306	1,315,693	2,635,931	64,982
50													
51													
52	Intangible Plant	P90	18,267,291	7,459,657	304,524	4,156,124	4,416,555	17,775	352,302	183,801	450,909	903,375	22,270
53													
54													
55	**Total Plant in Service**	EPIS	1,251,434,481	385,102,135	20,453,037	278,137,810	432,958,644	1,096,035	25,210,308	11,549,052	29,505,178	65,631,848	1,790,433
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Accumulated Depreciation												
2	Production Plant - Direct Assigned												
3													
4	Production Plant												
5	Base Demand	E1-E8760	(121,365,444)	(22,407,624)	(1,497,899)	(23,904,004)	(72,327,137)	0	(97,122)	(1,089,907)	(26,559)	0	(15,191)
6	Peak Demand	D1	(60,432,765)	(23,000,555)	(981,696)	(17,319,346)	(18,191,350)	0	(276,142)	(663,676)	0	0	0
7	Base Energy	E2-E8760	(64,152,219)	(12,882,015)	(729,527)	(10,139,148)	(33,347,154)	(31,984)	(293,285)	(461,038)	(775,538)	(5,134,235)	(358,293)
8													
9	**Total Production Plant**	P10	(245,950,428)	(58,290,195)	(3,209,122)	(51,362,499)	(123,865,642)	(31,984)	(666,549)	(2,214,621)	(802,098)	(5,134,235)	(373,483)
10													
11													
12	Transmission Plant	D2	(62,608,626)	(23,828,683)	(1,017,042)	(17,942,923)	(18,846,324)	0	(286,084)	(687,571)	0	0	0
13	Transmission Plant (Direct FERC)												
14													
15	**Total Transmission Plant**		(62,608,626)	(23,828,683)	(1,017,042)	(17,942,923)	(18,846,324)	0	(286,084)	(687,571)	0	0	0
16													
17													
18	Distribution Plant	P60	(123,383,577)	(45,660,290)	(2,807,178)	(25,732,343)	(13,245,443)	(345,691)	(7,842,411)	(1,052,172)	(9,426,906)	(17,076,139)	(195,002)
19													
20													
21	General Plant	P90	(21,909,367)	(8,946,940)	(365,239)	(4,984,759)	(5,297,114)	(21,319)	(422,542)	(220,446)	(540,810)	(1,083,487)	(26,711)
22													
23													
24	Intangible Plant	P90	(7,538,300)	(3,078,351)	(125,667)	(1,715,093)	(1,822,564)	(7,335)	(145,383)	(75,848)	(186,075)	(372,793)	(9,190)
25													
26													
27	**Total Accumulated Depreciation**		(461,390,298)	(139,804,458)	(7,524,247)	(101,737,617)	(163,077,087)	(406,330)	(9,362,970)	(4,250,659)	(10,955,888)	(23,666,655)	(604,387)
28													
29													
30	Net Plant Excluding BSP Capitalized Items		790,044,183	245,297,677	12,928,790	176,400,193	269,881,558	689,705	15,847,338	7,298,393	18,549,290	41,965,193	1,186,046
31													
32													
33	BSP Capitalized Items	P10	0	0	0	0	0	0	0	0	0	0	0
34													
35													
36	**Total Net Plant in Service**	NEPIS	790,044,183	245,297,677	12,928,790	176,400,193	269,881,558	689,705	15,847,338	7,298,393	18,549,290	41,965,193	1,186,046
37													
38													
39													
40													
41													
42													
43													
44													
45	Plant Held for Future Use												
46	Production Plant	P10	0	0	0	0	0	0	0	0	0	0	0
47	Transmission Plant	D2	3,542	1,348	58	1,015	1,066	0	16	39	0	0	0
48	Distribution Plant	P60	1,378	510	31	287	148	4	88	12	105	191	2
49	General Plant	P90	0	0	0	0	0	0	0	0	0	0	0
50	Intangible Plant	P90	0	0	0	0	0	0	0	0	0	0	0
51													
52	**Total Plant Held for Future Use**		4,921	1,858	89	1,303	1,214	4	104	51	105	191	2
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Const Work-in-Progress - Direct Assigned												
2	Production Plant	P10	0	0	0	0	0	0	0	0	0	0	0
3	Transmission Plant	D2	0	0	0	0	0	0	0	0	0	0	0
4	Distribution Plant	P60	0	0	0	0	0	0	0	0	0	0	0
5	General Plant	P90	0	0	0	0	0	0	0	0	0	0	0
6	Intangible Plant	P90	0	0	0	0	0	0	0	0	0	0	0
7													
8	**Total CWIP - Major Projects**		0	0	0	0	0	0	0	0	0	0	0
9													
10													
11	Const Work-in-Progress - Short-Term												
12	Production Plant	P10	0	0	0	0	0	0	0	0	0	0	0
13	Transmission Plant	D2	140,711	53,554	2,286	40,326	42,356	0	643	1,545	0	0	0
14	Distribution Plant	P60	499,127	184,711	11,356	104,096	53,582	1,398	31,725	4,256	38,135	69,079	789
15	General Plant	P90	141,155	57,642	2,353	32,115	34,128	137	2,722	1,420	3,484	6,981	172
16	Intangible Plant	P90	0	0	0	0	0	0	0	0	0	0	0
17													
18	**Total CWIP - Short-Term**		780,993	295,907	15,995	176,537	130,066	1,536	35,090	7,222	41,619	76,059	961
19													
20													
21	Const Work-in-Progress - Long Term												
22	Production Plant (AFUDC Projects)	P10	0	0	0	0	0	0	0	0	0	0	0
23	Production Plant (Rider Projects)	P10	0	0	0	0	0	0	0	0	0	0	0
24	Transmission Plant (AFUDC Projects)	D2	0	0	0	0	0	0	0	0	0	0	0
25	Transmission Plant (Rider Projects)	D2	0	0	0	0	0	0	0	0	0	0	0
26	Distribution Plant	P60	0	0	0	0	0	0	0	0	0	0	0
27	General Plant	P90	0	0	0	0	0	0	0	0	0	0	0
28	Intangible Plant	P90	0	0	0	0	0	0	0	0	0	0	0
29													
30	**Total CWIP - Long Term**		0	0	0	0	0	0	0	0	0	0	0
31													
32													
33	**Total Construction Work-in-Progress**		780,993	295,907	15,995	176,537	130,066	1,536	35,090	7,222	41,619	76,059	961
34													
35													
36	Materials & Supplies												
37	Production	P10	3,721,489	890,074	48,414	769,953	1,849,849	601	11,056	33,130	14,929	96,546	6,935
38	Transmission	D2	3,573,123	1,359,921	58,043	1,024,017	1,075,574	0	16,327	39,240	0	0	0
39	Distribution	P60	7,442,817	2,754,347	169,336	1,552,242	798,999	20,853	473,075	63,470	568,655	1,030,077	11,763
40													
41	**Total Materials and Supplies**		14,737,429	5,004,343	275,793	3,346,211	3,724,423	21,454	500,458	135,840	583,584	1,126,623	18,698
42													
43													
44	Fuel Stocks												
45	Coal Stocks	E1-E8760	3,582,674	661,467	44,218	705,639	2,135,077	0	2,867	32,174	784	0	448
46	Fuel Oil Stocks	D1	912,443	347,274	14,822	261,496	274,662	0	4,169	10,021	0	0	0
47													
48	**Total Fuel Stocks**		4,495,117	1,008,740	59,040	967,135	2,409,739	0	7,036	42,194	784	0	448
49													
50													
51	Prepayments	NEPIS	18,607,498	5,777,368	304,505	4,154,662	6,356,379	16,244	373,244	171,895	436,882	988,384	27,934
52													
53	Customer Advances	NEPIS	(709,884)	(220,409)	(11,617)	(158,502)	(242,499)	(620)	(14,239)	(6,558)	(16,667)	(37,707)	(1,066)
54													
55	Cash Working Capital	OX	1,531,800	456,514	21,174	309,290	604,143	871	12,613	13,428	22,207	86,300	5,260
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Otter Tail Power Company
North Dakota Class Cost of Service Study -- Normalized
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	**Accumulated Deferred Income Taxes**												
2	Items SD Flows Through												
3	Federal	NPMNR	(11,568)	(3,592)	(189)	(2,583)	(3,952)	(10)	(232)	(107)	(272)	(614)	(17)
4	Minnesota	NPISM	0	0	0	0	0	0	0	0	0	0	0
5	North Dakota	NPISN	0	0	0	0	0	0	0	0	0	0	0
6													
7	**Subtotal**		(11,568)	(3,592)	(189)	(2,583)	(3,952)	(10)	(232)	(107)	(272)	(614)	(17)
8													
9	All Other												
10	Federal	NEPIS	(115,026,544)	(35,714,134)	(1,882,368)	(25,683,000)	(39,293,426)	(100,418)	(2,307,294)	(1,062,610)	(2,700,685)	(6,109,926)	(172,682)
11	Federal (Direct FERC)	Direct FERC	0	0	0	0	0	0	0	0	0	0	0
12	Minnesota	NPISM	0	0	0	0	0	0	0	0	0	0	0
13	North Dakota	NPISN	(19,029,129)	(5,908,279)	(311,405)	(4,248,803)	(6,500,410)	(16,612)	(381,701)	(175,790)	(446,781)	(1,010,780)	(28,567)
14													
15	**Subtotal**		(134,055,673)	(41,622,413)	(2,193,773)	(29,931,803)	(45,793,836)	(117,030)	(2,688,996)	(1,238,400)	(3,147,466)	(7,120,706)	(201,250)
16													
17	**Total AccumulatedDeferred Income Taxes**		(134,067,241)	(41,626,005)	(2,193,962)	(29,934,386)	(45,797,788)	(117,040)	(2,689,228)	(1,238,507)	(3,147,738)	(7,121,320)	(201,267)
18													
19													
20	Unamortized Balance Spiritwood Expense	P10	0	0	0	0	0	0	0	0	0	0	0
21													
22													
23	Unamortized Rate Case Expenses	R10	0	0	0	0	0	0	0	0	0	0	0
24													
25													
26													
27													
28	**Total Average Rate Base**		695,424,815	215,995,994	11,399,807	155,262,442	237,067,236	612,155	14,072,417	6,423,958	16,470,066	37,083,723	1,037,017

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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Operating Revenues												
2	Sales of Electricity		182,782,835	50,921,629	2,639,772	38,503,051	72,695,877	94,067	3,056,500	1,358,947	2,381,778	10,409,315	721,900
3	Other Operating Revenue		12,253,679	3,670,653	185,280	2,518,671	4,590,063	9,360	189,264	107,085	241,577	711,240	30,486
4													
5	**Total Operating Revenue**		195,036,514	54,592,282	2,825,052	41,021,722	77,285,941	103,426	3,245,764	1,466,032	2,623,355	11,120,554	752,386
6													
7													
8	Operating Expenses												
9	Production Expenses		88,254,904	18,955,470	1,048,278	15,232,818	44,824,928	36,248	373,392	677,317	880,676	5,818,720	407,057
10	Transmission Expenses		14,086,555	5,361,307	228,828	4,037,047	4,240,307	0	64,367	154,699	0	0	0
11	Distribution Expenses		8,393,231	3,282,323	183,812	2,017,177	721,088	20,203	368,462	75,814	603,585	1,082,982	37,785
12	Customer Accounting Expenses		7,295,594	4,949,942	110,122	1,849,950	41,581	5,383	22,747	98,193	92,565	119,349	5,764
13	Customer Service and Information Expenses		1,331,017	1,026,867	22,830	257,643	5,802	669	2,812	13,167	312	893	22
14	Sales Expenses		135,872	104,824	2,330	26,301	592	68	287	1,344	32	91	2
15	Administrative and General Expenses		20,770,596	8,122,478	342,731	4,900,892	5,487,403	17,185	322,939	209,087	456,321	880,533	31,027
16	Charitable Contributions		0	0	0	0	0	0	0	0	0	0	0
17	Depreciation Expense		33,165,286	10,194,729	539,656	7,217,071	11,470,402	30,661	686,048	303,071	821,569	1,849,753	52,325
18	Amortization of Big Stone Plant Capitalized Costs		0	0	0	0	0	0	0	0	0	0	0
19	Spiritwood Amortization		0	0	0	0	0	0	0	0	0	0	0
20	General Taxes		7,103,512	2,185,953	116,097	1,578,792	2,457,601	6,221	143,101	65,556	167,480	372,546	10,163
21													
22	**Total Operating Expenses**		180,536,568	54,183,894	2,594,685	37,117,691	69,249,705	116,638	1,984,156	1,598,248	3,022,539	10,124,867	544,145
23													
24													
25	**Net Operating Income Before Income Taxes**		14,499,946	408,388	230,367	3,904,031	8,036,236	(13,212)	1,261,609	(132,216)	(399,184)	995,687	208,240
26													
27													
28	Income Tax Expense												
29	Investment Tax Credit		(2,939,619)	(621,479)	(34,879)	(483,332)	(1,477,338)	(1,576)	(17,982)	(21,722)	(38,888)	(227,216)	(15,206)
30	Deferred Income Taxes		(2,550,314)	(791,837)	(41,735)	(569,431)	(871,195)	(2,226)	(51,156)	(23,560)	(59,878)	(135,466)	(3,829)
31	Income Taxes		0	0	0	0	0	0	0	0	0	0	0
32													
33	**Total Income Tax Expense**		(5,489,933)	(1,413,316)	(76,614)	(1,052,764)	(2,348,533)	(3,802)	(69,138)	(45,281)	(98,767)	(362,682)	(19,035)
34													
35													
36													
37	**Net Operating Income**		**19,989,879**	**1,821,704**	**306,981**	**4,956,795**	**10,384,769**	**(9,410)**	**1,330,747**	**(86,935)**	**(300,417)**	**1,358,370**	**227,275**
38													
39	Allowance for Funds Used During Construction		0	0	0	0	0	0	0	0	0	0	0
40	Allowance for Funds Used During Construction - Direct Assigned		0	0	0	0	0	0	0	0	0	0	0
41													
42	**Total Allowance for Funds Used During Construction**		0	0	0	0	0	0	0	0	0	0	0
43													
44													
45	**Total Available for Return**		19,989,879	1,821,704	306,981	4,956,795	10,384,769	(9,410)	1,330,747	(86,935)	(300,417)	1,358,370	227,275
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Otter Tail Power Company
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Operating Revenues												
2													
3	**Sales of Electricity**	Directly Assigned	182,782,835	50,921,629	2,639,772	38,503,051	72,695,877	94,067	3,056,500	1,358,947	2,381,778	10,409,315	721,900
4													
5													
6	Other Operating Revenues												
7	Sales for Resale												
8	Municipalities		0										
9	Non-Associated Utilities, Co-Ops & OPA												
10	Non-Asset Wholesale Transactions	D2	0	0	0	0	0	0	0	0	0	0	0
11	All Other Transactions												
12	Base Demand	E1-E8760	0	0	0	0	0	0	0	0	0	0	0
13	Peak Demand	D1	0	0	0	0	0	0	0	0	0	0	0
14	Base Energy	E2-E8760	3,125,191	627,550	35,539	493,931	1,624,515	1,558	14,287	22,460	37,781	250,115	17,454
15	Peak Energy	D1	0	0	0	0	0	0	0	0	0	0	0
16													
17	**Total All Other Transactions**		3,125,191	627,550	35,539	493,931	1,624,515	1,558	14,287	22,460	37,781	250,115	17,454
18													
19	**Total Sales for Resale**		3,125,191	627,550	35,539	493,931	1,624,515	1,558	14,287	22,460	37,781	250,115	17,454
20													
21													
22	Other Electric Revenues												
23	Late Fees	C1	316,187	243,935	5,423	61,204	1,378	159	668	3,128	74	212	5
24	Connection Fees	C1	136,812	105,549	2,347	26,482	596	69	289	1,353	32	92	2
25	Rent from Electric Property	NEPIS	164,912	51,203	2,699	36,821	56,334	144	3,308	1,523	3,872	8,760	248
26	Rent from Electric Property - Big Stone	NEPIS	0	0	0	0	0	0	0	0	0	0	0
27	Rent from Electric Property - Coyote	NEPIS	0	0	0	0	0	0	0	0	0	0	0
28	Other Misc Electric Revenue	NEPIS	528,058	163,955	8,641	117,904	180,386	461	10,592	4,878	12,398	28,049	793
29	Other Misc Electric Revenue	C1	0	0	0	0	0	0	0	0	0	0	0
30	ITA Deficiency Payments	NEPIS	321,083	99,692	5,254	71,691	109,683	280	6,441	2,966	7,539	17,055	482
31	Sales of Supplies	NEPIS	0	0	0	0	0	0	0	0	0	0	0
32	Miscellaneous Services	NEPIS	0	0	0	0	0	0	0	0	0	0	0
33	Wheeling												
34	Load Control and Dispatch	NEPIS	7,661,436	2,378,769	125,377	1,710,637	2,617,170	6,688	153,679	70,776	179,881	406,957	11,502
35	Load Control and Dispatch (Direct FERC)	Direct FERC					0						
36	Loan Pool Interest	C1	0	0	0	0	0	0	0	0	0	0	0
37													
38	**Total Other Electric Revenues**		9,128,488	3,043,102	149,741	2,024,740	2,965,549	7,802	174,977	84,625	203,796	461,124	13,032
39													
40	**Total Other Operating Revenues**		12,253,679	3,670,653	185,280	2,518,671	4,590,063	9,360	189,264	107,085	241,577	711,240	30,486
41													
42													
43	**Total Operating Revenues**		195,036,514	54,592,282	2,825,052	41,021,722	77,285,941	103,426	3,245,764	1,466,032	2,623,355	11,120,554	752,386
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Otter Tail Power Company
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	**Operating Expenses**												
2	Production Expenses												
3	Prod Expenses Excluding Purchased Power												
4	Base Demand	E1-E8760	7,128,759	1,316,178	87,984	1,404,072	4,248,349	0	5,705	64,019	1,560	0	892
5	Peak Demand	D1	3,472,693	1,321,698	56,412	995,234	1,045,343	0	15,868	38,137	0	0	0
6	Base Energy	E2-E8760	31,520,644	6,329,468	358,447	4,981,784	16,384,839	15,715	144,103	226,527	381,054	2,522,663	176,044
7	Peak Energy	D1	4,105,359	1,562,489	66,689	1,176,549	1,235,787	0	18,759	45,085	0	0	0
8	Base Demand (Direct MN)	E1-E8760	0	0	0	0	0	0	0	0	0	0	0
9	Peak Demand (Direct MN)	D1	0	0	0	0	0	0	0	0	0	0	0
10													
11	**Total Excluding Purchased Power**		46,227,454	10,529,833	569,532	8,557,640	22,914,318	15,715	184,435	373,769	382,614	2,522,663	176,936
12													
13													
14	Purchased Power												
15	Non-Asset Wholesale Transactions	D2	0	0	0	0	0	0	0	0	0	0	0
16	for Retail												
17	Base Demand	E1-E8760	843,238	155,686	10,407	166,083	502,524	0	675	7,573	185	0	106
18	Peak Demand	D1	0	0	0	0	0	0	0	0	0	0	0
19	Base Energy	E2-E8760	41,184,212	8,269,950	468,339	6,509,094	21,408,087	20,533	188,282	295,976	497,877	3,296,058	230,015
20	Peak Energy	D1	0	0	0	0	0	0	0	0	0	0	0
21													
22	**Total All Other Transactions**		42,027,450	8,425,637	478,746	6,675,177	21,910,610	20,533	188,957	303,548	498,062	3,296,058	230,121
23													
24	**Total Purchased Power**		42,027,450	8,425,637	478,746	6,675,177	21,910,610	20,533	188,957	303,548	498,062	3,296,058	230,121
25													
26	**Total Production Expenses**		88,254,904	18,955,470	1,048,278	15,232,818	44,824,928	36,248	373,392	677,317	880,676	5,818,720	407,057
27													
28													
29	Transmission Expenses	D2	14,086,555	5,361,307	228,828	4,037,047	4,240,307	0	64,367	154,699	0	0	0
30	Transmission Expenses (Direct MN)	D2	0	0	0	0	0	0	0	0	0	0	0
31	Transmission Expenses (Direct FERC)												
32													
33	**Total Transmission Expenses**		14,086,555	5,361,307	228,828	4,037,047	4,240,307	0	64,367	154,699	0	0	0
34													
35													
36	**Distribution Expenses**												
37	Primary Demand	D3	2,418,865	550,346	61,443	519,023	525,276	9,930	28,862	19,817	217,391	486,778	0
38	Secondary Demand	D4	1,107,378	251,772	37,478	245,679	137,300	5,392	8,945	10,439	164,034	246,340	0
39	Primary Customer	C2	1,712,244	1,321,116	29,369	331,528	7,493	861	3,502	16,938	402	1,005	29
40	Secondary Customer	C3	625,745	482,887	10,735	121,105	2,707	315	1,280	6,191	147	367	10
41	Streetlighting	C4	219,347	0	0	0	0	0	219,347	0	0	0	0
42	Area Lighting	C5	100,232	0	0	0	0	0	100,232	0	0	0	0
43	Meters	C6	2,209,420	676,202	44,788	799,843	48,312	3,705	6,293	22,428	221,611	348,493	37,746
44	Load Management	C9	0	0	0	0	0	0	0	0	0	0	0
45													
46	**Total Distribution Expense**	OXD	8,393,231	3,282,323	183,812	2,017,177	721,088	20,203	368,462	75,814	603,585	1,082,982	37,785
47													
48													
49	Customer Accounting Expenses												
50	Meter Reading	C7	2,685,754	1,393,185	31,054	957,398	21,331	3,064	13,317	52,591	91,482	116,644	5,686
51	Other	C8	4,609,841	3,556,757	79,068	892,551	20,250	2,319	9,429	45,601	1,082	2,705	77
52													
53	**Total Customer Accounts**	OXC	7,295,594	4,949,942	110,122	1,849,950	41,581	5,383	22,747	98,193	92,565	119,349	5,764
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Otter Tail Power Company
North Dakota Class Cost of Service Study -- Normalized
2024 Projected Test Year - Supplemental

Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Customer Service & Information Expense												
2	Conservation & DSM Rebates - CIP only	E2-E8760	0	0	0	0	0	0	0	0	0	0	0
3	Customer Assistance Expenses	C1	0	0	0	0	0	0	0	0	0	0	0
4	Other	C1	1,331,017	1,026,867	22,830	257,643	5,802	669	2,812	13,167	312	893	22
5													
6	**Total Customer Service & Information Expense**	OXI	1,331,017	1,026,867	22,830	257,643	5,802	669	2,812	13,167	312	893	22
7													
8													
9	Sales Expenses												
10	Off-Peak Development	C1	0	0	0	0	0	0	0	0	0	0	0
11	Other	C1	135,872	104,824	2,330	26,301	592	68	287	1,344	32	91	2
12													
13	**Total Sales Expenses**		135,872	104,824	2,330	26,301	592	68	287	1,344	32	91	2
14													
15													
16	Administrative & General Expenses												
17	Salaries, Supplies, Pensions & Benefits												
18	Production	OXPD	4,706,353	1,148,785	63,659	1,054,955	2,383,554	0	9,149	45,123	717	0	410
19	Transmission	D2	2,067,479	786,877	33,585	592,516	622,348	0	9,447	22,705	0	0	0
20	Distribution	OXD	3,707,720	1,449,970	81,199	891,091	318,542	8,925	162,769	33,491	266,634	478,409	16,692
21	Customer Accounts	OXC	2,851,965	1,935,012	43,049	723,175	16,255	2,104	8,892	38,385	36,185	46,655	2,253
22	Customer Service & Info	C1	664,905	512,968	11,404	128,705	2,899	334	1,405	6,577	156	446	11
23													
24	**Total Salaries, Supplies, Pensions,and Benefits**		13,998,422	5,833,612	232,896	3,390,441	3,343,597	11,363	191,661	146,282	303,693	525,510	19,366
25													
26	Load Management Expenses	C9	0	0	0	0	0	0	0	0	0	0	0
27													
28	Outside Services	NEPIS	410,041	127,312	6,710	91,553	140,071	358	8,225	3,788	9,627	21,780	616
29													
30	Property Insurance	NEPIS	1,600,563	496,952	26,193	357,372	546,757	1,397	32,105	14,786	37,579	85,018	2,403
31													
32	Injuries & Damages	NEPIS	1,716,306	532,889	28,087	383,215	586,296	1,498	34,427	15,855	40,297	91,166	2,577
33													
34	Regulatory Commission Expense	R10	861,954	240,133	12,448	181,570	342,814	444	14,414	6,408	11,232	49,087	3,404
35													
36	General Advertising	C1	0	0	0	0	0	0	0	0	0	0	0
37													
38	Miscellaneous, Rents, Maintenance	P90	2,183,311	891,580	36,397	496,741	527,868	2,125	42,107	21,968	53,893	107,972	2,662
39													
40	**Total Administrative & General Exp**		20,770,596	8,122,478	342,731	4,900,892	5,487,403	17,185	322,939	209,087	456,321	880,533	31,027
41													
42													
43	Charitable Contributions	C1	0	0	0	0	0	0	0	0	0	0	0
44													
45													
46													
47	**Total O & M Expenses**		140,267,771	41,803,211	1,938,931	28,321,827	55,321,702	79,756	1,155,006	1,229,621	2,033,490	7,902,568	481,658
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Otter Tail Power Company
North Dakota Class Cost of Service Study -- Normalized
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	**Depreciation Expense**												
2	Production												
3	Base Demand	E1-E8760	7,011,106	1,294,456	86,531	1,380,900	4,178,234	0	5,611	62,962	1,534	0	878
4	Peak Demand	D1	4,398,123	1,673,914	71,445	1,260,452	1,323,914	0	20,097	48,300	0	0	0
5	Base Energy	E2-E8760	5,953,955	1,195,577	67,707	941,012	3,094,943	2,968	27,220	42,789	71,978	476,507	33,253
6													
7	**Total Production**		17,363,184	4,163,948	225,684	3,582,364	8,597,091	2,968	52,927	154,052	73,512	476,507	34,131
8													
9													
10	Transmission	D2	3,412,667	1,298,852	55,437	978,032	1,027,274	0	15,594	37,478	0	0	0
11	Transmission (Direct FERC)												
12													
13	**Total Transmission**		3,412,667	1,298,852	55,437	978,032	1,027,274	0	15,594	37,478	0	0	0
14													
15													
16	Distribution	P60	8,550,713	3,164,344	194,543	1,783,300	917,934	23,957	543,494	72,918	653,302	1,183,408	13,514
17													
18													
19	General	P90	1,836,834	750,092	30,621	417,911	444,099	1,787	35,425	18,482	45,340	90,837	2,239
20													
21													
22	Intangible	P90	2,001,888	817,494	33,372	455,464	484,004	1,948	38,608	20,142	49,414	99,000	2,441
23													
24													
25	**Total Depreciation Expense**		33,165,286	10,194,729	539,656	7,217,071	11,470,402	30,661	686,048	303,071	821,569	1,849,753	52,325
26													
27													
28													
29													
30													
31													
32	Big Stone Expense Offsets	P10	0	0	0	0	0	0	0	0	0	0	0
33													
34													
35	Spiritwood Amortization	P10	0	0	0	0	0	0	0	0	0	0	0
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Otter Tail Power Company
North Dakota Class Cost of Service Study -- Normalized
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	General Taxes	EPIS	7,103,512	2,185,953	116,097	1,578,792	2,457,601	6,221	143,101	65,556	167,480	372,546	10,163
2	General Taxes (Direct FERC)		0	0	0	0	0	0	0	0	0	0	0
3													
4	**TOTAL GENERAL TAXES**		7,103,512	2,185,953	116,097	1,578,792	2,457,601	6,221	143,101	65,556	167,480	372,546	10,163
5													
6	Net Operating Income Before Tax (NOIBT)		14,499,946	408,388	230,367	3,904,031	8,036,236	(13,212)	1,261,609	(132,216)	(399,184)	995,687	208,240
7													
8	Investment Tax Credit												
9	Production Tax Credits	E2-E8760	(2,647,896)	(531,708)	(30,111)	(418,495)	(1,376,411)	(1,320)	(12,105)	(19,029)	(32,011)	(211,917)	(14,789)
10	ITC Tax Credits	EPIS	0	0	0	0	0	0	0	0	0	0	0
11	Amortize Prior Years Credit	EPIS	(291,723)	(89,771)	(4,768)	(64,837)	(100,927)	(255)	(5,877)	(2,692)	(6,878)	(15,299)	(417)
12	Debits Utilized	EPIS	0	0	0	0	0	0	0	0	0	0	0
13													
14	**Total Investment Tax Credit**		(2,939,619)	(621,479)	(34,879)	(483,332)	(1,477,338)	(1,576)	(17,982)	(21,722)	(38,888)	(227,216)	(15,206)
15													
16	Deferred Income Taxes												
17	Items South Dakota Flows Through												
18	Federal	NPMNR	0	0	0	0	0	0	0	0	0	0	0
19	Minnesota	NPISM	0	0	0	0	0	0	0	0	0	0	0
20	North Dakota	NPISN	(31,515)	(9,785)	(516)	(7,037)	(10,766)	(28)	(632)	(291)	(740)	(1,674)	(47)
21													
22	**Subtotal**		(31,515)	(9,785)	(516)	(7,037)	(10,766)	(28)	(632)	(291)	(740)	(1,674)	(47)
23													
24	All Other												
25	Federal - transfer from Current Income Taxes - NOL	NEPIS	(6,751,481)	(2,096,240)	(110,486)	(1,507,463)	(2,306,327)	(5,894)	(135,427)	(62,370)	(158,517)	(358,622)	(10,136)
26	Federal (NEPIS)	NEPIS	4,574,141	1,420,207	74,854	1,021,309	1,562,541	3,993	91,752	42,256	107,395	242,967	6,867
27	**Federal**		(2,177,340)	(676,034)	(35,631)	(486,154)	(743,786)	(1,901)	(43,675)	(20,114)	(51,121)	(115,655)	(3,269)
28	Minnesota - transfer from Current Income Taxes - NOL	NPISM	0	0	0	0	0	0	0	0	0	0	0
29	Minnesota (NPISM)	NPISM	0	0	0	0	0	0	0	0	0	0	0
30	**Minnesota**		0	0	0	0	0	0	0	0	0	0	0
31	North Dakota - transfer from Current Income Taxes - NOL	NPISN	(1,449,105)	(449,927)	(23,714)	(323,554)	(495,019)	(1,265)	(29,067)	(13,387)	(34,023)	(76,973)	(2,175)
32	North Dakota (NPISN)	NPISN	1,107,645	343,908	18,126	247,314	378,375	967	22,218	10,232	26,006	58,835	1,663
33	**North Dakota**		(341,459)	(106,018)	(5,588)	(76,241)	(116,644)	(298)	(6,849)	(3,154)	(8,017)	(18,137)	(513)
34													
35	**Subtotal**		(2,518,800)	(782,052)	(41,219)	(562,395)	(860,430)	(2,199)	(50,524)	(23,269)	(59,138)	(133,792)	(3,781)
36													
37	**Total Deferred Income Taxes**		(2,550,314)	(791,837)	(41,735)	(569,431)	(871,195)	(2,226)	(51,156)	(23,560)	(59,878)	(135,466)	(3,829)
38													
39													
40	Current Income Taxes												
41	Federal - transfer to Deferred Income Taxes - NOL		6,751,481	2,919,165	111,961	1,373,485	1,684,661	11,115	(59,102)	115,853	307,763	313,945	(27,365)
42	Federal Current Income Tax		(6,751,481)	(2,919,165)	(111,961)	(1,373,485)	(1,684,661)	(11,115)	59,102	(115,853)	(307,763)	(313,945)	27,365
43	Federal Income Taxes		0	0	0	0	0	0	0	0	0	0	0
44	Minnesota - transfer to Deferred Income Taxes - NOL		0	0	0	0	0	0	0	0	0	0	0
45	Minnesota Current Income Tax		0	0	0	0	0	0	0	0	0	0	0
46	Minnesota Income Taxes		0	0	0	0	0	0	0	0	0	0	0
47	North Dakota - transfer to Deferred Income Taxes - NOL		1,449,105	626,546	24,031	294,800	361,594	2,386	(12,683)	24,865	66,055	67,384	(5,873)
48	North Dakota Current Income Tax		(1,449,105)	(626,546)	(24,031)	(294,800)	(361,594)	(2,386)	12,683	(24,865)	(66,055)	(67,384)	5,873
49	North Dakota Income Taxes		0	0	0	0	0	0	0	0	0	0	0
50													
51	**Total Current Income Taxes**		0	0	0	0	0	0	0	0	0	0	0
52													
53	**Total Income Taxes**		(5,489,933)	(1,413,316)	(76,614)	(1,052,764)	(2,348,533)	(3,802)	(69,138)	(45,281)	(98,767)	(362,682)	(19,035)
54													
55													
56	**Net Operating Income**		19,989,879	1,821,704	306,981	4,956,795	10,384,769	(9,410)	1,330,747	(86,935)	(300,417)	1,358,370	227,275
57													
58	AFUDC	CWIPLT	0	0	0	0	0	0	0	0	0	0	0
59	AFUDC - Direct Assigned	CWIPLT	0	0	0	0	0	0	0	0	0	0	0
60													
61	**Total AFUDC**	CWIPLT	0	0	0	0	0	0	0	0	0	0	0
62													
63	**Total Available for Return**		19,989,879	1,821,704	306,981	4,956,795	10,384,769	(9,410)	1,330,747	(86,935)	(300,417)	1,358,370	227,275
64													
65													
66	Rate of Return on Rate Base		2.87%	0.84%	2.69%	3.19%	4.38%	-1.54%	9.46%	-1.35%	-1.82%	3.66%	21.92%
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Otter Tail Power Company
North Dakota Class Cost of Service Study -- Normalized
2024 Projected Test Year - Supplemental

Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Development of Federal Income Tax Expense												
2													
3	Net Operating Income Before Tax (NOIBT)		14,499,946	408,388	230,367	3,904,031	8,036,236	(13,212)	1,261,609	(132,216)	(399,184)	995,687	208,240
4	Less: Interest Cost		15,160,261	4,708,713	248,516	3,384,721	5,168,066	13,345	306,779	140,042	359,047	808,425	22,607
5													
6	Net Income Before Tax		(660,315)	(4,300,325)	(18,149)	519,310	2,868,170	(26,557)	954,830	(272,258)	(758,232)	187,262	185,633
7													
8	Federal Schedule M Adjustments:												
9	Additional Tax Depreciation	NEPIS	28,652,304	8,896,140	468,885	6,397,455	9,787,716	25,013	574,731	264,689	672,722	1,521,940	43,014
10	Other Schedule M Items	NEPIS	4,286,394	1,330,866	70,145	957,061	1,464,246	3,742	85,980	39,598	100,639	227,683	6,435
11	Directly Assigned Schedule M Items	NEPIS	0	0	0	0	0	0	0	0	0	0	0
12													
13	**Subtotal Federal Schedule M Adjustments**		32,938,698	10,227,006	539,030	7,354,516	11,251,962	28,755	660,711	304,286	773,361	1,749,622	49,449
14													
15	**Federal Adjusted Income Before Income Taxes**		(33,599,014)	(14,527,330)	(557,179)	(6,835,207)	(8,383,792)	(55,312)	294,119	(576,544)	(1,531,593)	(1,562,360)	136,184
16													
17	Less:												
18	Minnesota State Income Taxes		0	0	0	0	0	0	0	0	0	0	0
19	North Dakota State Income Taxes		(1,449,105)	(626,546)	(24,031)	(294,800)	(361,594)	(2,386)	12,683	(24,865)	(66,055)	(67,384)	5,873
20													
21	**Federal Taxable Income**		(32,149,909)	(13,900,784)	(533,148)	(6,540,407)	(8,022,198)	(52,927)	281,436	(551,679)	(1,465,538)	(1,494,976)	130,311
22	Federal Tax Rate		21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
23													
24	Federal Income Tax Before Credits		(6,751,481)	(2,919,165)	(111,961)	(1,373,485)	(1,684,661)	(11,115)	59,102	(115,853)	(307,763)	(313,945)	27,365
25	Investment Tax Credit - Debits Utilized	EPIS	0	0	0	0	0	0	0	0	0	0	0
26	**Federal Income Tax before transfer to Deferred due to NOL**		(6,751,481)	(2,919,165)	(111,961)	(1,373,485)	(1,684,661)	(11,115)	59,102	(115,853)	(307,763)	(313,945)	27,365
27	Less Current Federal Income Taxes Transferred to Deferred Income Tax		6,751,481	2,919,165	111,961	1,373,485	1,684,661	11,115	(59,102)	115,853	307,763	313,945	(27,365)
28	**Federal Income Taxes**		0	0	0	0	0	0	0	0	0	0	0
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Development of Minnesota State Income Tax Expense												
2													
3	**Federal Adjusted Income Before Income Taxes**	EPIS	0	0	0	0	0	0	0	0	0	0	0
4													
5	Minnesota Adjustments to Federal Schedule M:												
6	Change in Excess Tax Depreciation - MN	NEPIS	0	0	0	0	0	0	0	0	0	0	0
7	Change in ACRS - Ordinary Loss	NEPIS	0	0	0	0	0	0	0	0	0	0	0
8	Miscellaneous Adjustments to Fed Schedule M	NEPIS	0	0	0	0	0	0	0	0	0	0	0
9													
10	**Total Minnesota Adjustments to Fed Schedule M**		0	0	0	0	0	0	0	0	0	0	0
11													
12	Minnesota Taxable Income		0	0	0	0	0	0	0	0	0	0	0
13	Minnesota Tax Rate		9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
14			0										
15	Minnesota Income Tax prior to transfer to Deferred Income Tax due to N		0	0	0	0	0	0	0	0	0	0	0
16	Less Minnesota Current Income Tax transfer to Deferred Income Tax du	NEPIS	0	0	0	0	0	0	0	0	0	0	0
17	**Minnesota Income Tax**		0	0	0	0	0	0	0	0	0	0	0
18													
19													
20													
21													
22													
23													
24													
25	Development of North Dakota State Income Tax Expense												
26													
27	**Federal Adjusted Income Before Income Taxes**		(33,599,014)	(14,527,330)	(557,179)	(6,835,207)	(8,383,792)	(55,312)	294,119	(576,544)	(1,531,593)	(1,562,360)	136,184
28													
29	North Dakota Adjustments to Federal Schedule M:												
30	Change in Excess Tax Depreciation - ND	NEPIS	(1,671)	(519)	(27)	(373)	(571)	(1)	(34)	(15)	(39)	(89)	(3)
31	Change in ACRS - Ordinary Loss - ND	NEPIS	0	0	0	0	0	0	0	0	0	0	0
32	Change in Income from ADR Property - ND	NEPIS	0	0	0	0	0	0	0	0	0	0	0
33	Miscellaneous Adjustments to Fed Schedule M	NEPIS	0	0	0	0	0	0	0	0	0	0	0
34													
35	**Total North Dakota Adjustments to Fed Schedule M**		(1,671)	(519)	(27)	(373)	(571)	(1)	(34)	(15)	(39)	(89)	(3)
36													
37	**Subtotal**		(33,600,685)	(14,527,849)	(557,206)	(6,835,580)	(8,384,363)	(55,314)	294,086	(576,560)	(1,531,632)	(1,562,449)	136,182
38	Deduction of Federal Income Taxes		0	0	0	0	0	0	0	0	0	0	0
39													
40	**North Dakota Taxable Income**		(33,650,685)	(14,549,468)	(558,036)	(6,845,752)	(8,396,839)	(55,396)	294,523	(577,418)	(1,533,911)	(1,564,774)	136,384
41	North Dakota Tax Rate		4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
42													
43	North Dakota Income Tax prior to transfer to Deferred Income Tax due t		(1,449,105)	(626,546)	(24,031)	(294,800)	(361,594)	(2,386)	12,683	(24,865)	(66,055)	(67,384)	5,873
44	Less North Dakota Current Income Tax transfer to Deferred Income Tax	NEPIS	1,449,105	626,546	24,031	294,800	361,594	2,386	(12,683)	24,865	66,055	67,384	(5,873)
45	**North Dakota Income Tax**		0	0	0	0	0	0	0	0	0	0	0
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Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	MWH Consumption at Generators - Partial	E1-E8760	2,476,735	457,278	30,568	487,815	1,475,998	0	1,982	22,242	542	0	310
2	Percentage		100.00000%	18.46294%	1.23421%	19.69589%	59.59451%	0.00000%	0.08002%	0.89804%	0.02188%	0.00000%	0.01252%
3													
4	MWH Consumption at Generators - Total	E2-E8760	2,775,987	557,429	31,568	438,740	1,442,994	1,384	12,691	19,950	33,559	222,168	15,504
5	Percentage		100.00000%	20.08039%	1.13718%	15.80483%	51.98130%	0.04986%	0.45717%	0.71866%	1.20890%	8.00321%	0.55850%
6													
7	Generation Demand Factor	D1	284,282	108,197	4,618	81,472	85,574	0	1,299	3,122	0	0	0
8	Percentage		100.00000%	38.05974%	1.62444%	28.65887%	30.10180%	0.00000%	0.45694%	1.09821%	0.00000%	0.00000%	0.00000%
9													
10	Transmission Demand Factor	D2	284,282	108,197	4,618	81,472	85,574	0	1,299	3,122	0	0	0
11	Percentage		100.00000%	38.05974%	1.62444%	28.65887%	30.10180%	0.00000%	0.45694%	1.09821%	0.00000%	0.00000%	0.00000%
12													
13	Distribution - Primary Demand Factor	D3	396,080	90,117	10,061	84,988	86,012	1,626	4,726	3,245	35,597	79,708	0
14	Percentage		100.00000%	22.75222%	2.54014%	21.45728%	21.71581%	0.41052%	1.19319%	0.81928%	8.98733%	20.12422%	0.00000%
15													
16	Distribution - Secondary Demand Factor	D4	545,068	123,926	18,447	120,927	67,581	2,654	4,403	5,138	80,740	121,252	0
17	Percentage		100.00000%	22.73588%	3.38435%	22.18567%	12.39864%	0.48691%	0.80779%	0.94263%	14.81283%	22.24530%	0.00000%
18													
19	**Customer or Meter Factors**												
20	Total Retail Customers	C1	59,643	46,014	1,023	11,545	260	30	126	590	14	40	1
21	Percentage		100.00000%	77.14904%	1.71521%	19.35684%	0.43593%	0.05030%	0.21126%	0.98922%	0.02347%	0.06707%	0.00168%
22													
23	Retail Service Locations	C2	59,642	46,018	1,023	11,548	261	30	122	590	14	35	1
24	Percentage		100.00000%	77.15704%	1.71523%	19.36219%	0.43761%	0.05030%	0.20455%	0.98924%	0.02347%	0.05868%	0.00168%
25													
26	Secondary Service Locations	C3	59,632	46,018	1,023	11,541	258	30	122	590	14	35	1
27	Percentage		100.00000%	77.16998%	1.71552%	19.35370%	0.43265%	0.05031%	0.20459%	0.98940%	0.02348%	0.05869%	0.00168%
28													
29	Street Lighting Factor	C4	5,515,574	0	0	0	0	0	5,515,574	0	0	0	0
30	Percentage		100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%
31													
32	Area Lighting Factor	C5	5,249,227	0	0	0	0	0	5,249,227	0	0	0	0
33	Percentage		100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%
34													
35	Meter Factor	C6	25,668,459	7,855,936	520,335	9,292,360	561,276	43,040	73,114	260,568	2,574,614	4,048,696	438,520
36	Percentage		100.00000%	30.60541%	2.02714%	36.20147%	2.18664%	0.16768%	0.28484%	1.01513%	10.03026%	15.77304%	1.70840%
37													
38	Meter Reading Factor	C7	91,157	47,286	1,054	32,495	724	104	452	1,785	3,105	3,959	193
39	Percentage		100.00000%	51.87314%	1.15625%	35.64729%	0.79423%	0.11409%	0.49585%	1.95816%	3.40621%	4.34306%	0.21172%
40													
41	System Service Locations	C8	59,643	46,018	1,023	11,548	262	30	122	590	14	35	1
42	Percentage		100.00000%	77.15574%	1.71521%	19.36187%	0.43928%	0.05030%	0.20455%	0.98922%	0.02347%	0.05868%	0.00168%
43													
44	Load Management Factor	C9	18,119	3,882	18	34	1	21	1	0	6,130	7,902	130
45	Percentage		100.00000%	21.42502%	0.09934%	0.18765%	0.00552%	0.11590%	0.00552%	0.00000%	33.83189%	43.61168%	0.71748%
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Otter Tail Power Company
North Dakota Class Cost of Service Study -- Normalized
2024 Projected Test Year - Supplemental

Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Gross Plant in Service												
2	Production Plant	P10	634,293,606	151,705,021	8,251,688	131,231,377	315,289,834	102,509	1,884,476	5,646,786	2,544,516	16,455,376	1,182,023
3	Percentage		100.00000%	23.91716%	1.30093%	20.68937%	49.70724%	0.01616%	0.29710%	0.89025%	0.40116%	2.59428%	0.18635%
4													
5	Distribution Plant	P60	329,751,161	122,030,291	7,502,377	68,771,469	35,399,364	923,884	20,959,387	2,812,003	25,194,060	45,637,166	521,158
6	Percentage		100.00000%	37.00678%	2.27516%	20.85557%	10.73518%	0.28018%	6.35612%	0.85277%	7.64033%	13.83988%	0.15805%
7													
8	General Plant	P90	53,301,572	21,766,304	888,560	12,127,028	12,886,930	51,866	1,027,970	536,306	1,315,693	2,635,931	64,982
9	Percentage		100.00000%	40.8361%	1.6670%	22.7517%	24.1774%	0.0973%	1.92859%	1.00617%	2.46839%	4.94532%	0.12191%
10													
11													
12	Electric Plant in Service	EPIS	1,251,434,481	385,102,135	20,453,037	278,137,810	432,958,644	1,096,035	25,210,308	11,549,052	29,505,178	65,631,848	1,790,433
13	Percentage		100.00000%	30.77286%	1.63437%	22.22552%	34.59699%	0.08758%	2.01451%	0.92287%	2.35771%	5.24453%	0.14307%
14													
15	Net Electric Plant in Service	NEPIS	790,044,183	245,297,677	12,928,790	176,400,193	269,881,558	689,705	15,847,338	7,298,393	18,549,290	41,965,193	1,186,046
16	Percentage		100.00000%	31.04860%	1.63646%	22.32789%	34.16031%	0.08730%	2.00588%	0.92380%	2.34788%	5.31175%	0.15012%
17													
18	Net Electric Plant in Service - Excluding Direct Assignment	NEPISEXDA											
19	Percentage												
20													
21	Operation and Maintenance Expense												
22	Production Expense (Excl Energy)	OXPD	11,444,689	2,793,563	154,803	2,565,390	5,796,215	0	22,248	109,729	1,745	0	998
23	Percentage		100.00000%	24.40925%	1.35262%	22.41555%	50.64546%	0.00000%	0.19439%	0.95877%	0.01524%	0.00000%	0.00872%
24													
25	Distribution Expense	OXD	8,393,231	3,282,323	183,812	2,017,177	721,088	20,203	368,462	75,814	603,585	1,082,982	37,785
26	Percentage		100.00000%	39.10679%	2.19000%	24.03338%	8.59131%	0.24070%	4.38999%	0.90327%	7.19133%	12.90304%	0.45018%
27													
28	Customer Accounts Expense	OXC	7,295,594	4,949,942	110,122	1,849,950	41,581	5,383	22,747	98,193	92,565	119,349	5,764
29	Percentage		100.00000%	67.84837%	1.50943%	25.35708%	0.56995%	0.07378%	0.31179%	1.34592%	1.26877%	1.63590%	0.07900%
30													
31	Customer Service & Information Expense	OXI	1,331,017	1,026,867	22,830	257,643	5,802	669	2,812	13,167	312	893	22
32	Percentage		100.00000%	77.14904%	1.71521%	19.35684%	0.43593%	0.05030%	0.21126%	0.98922%	0.02347%	0.06707%	0.00168%
33													
34	Other Deferred Income Tax Factor												
35	Minnesota	NPISM	0	0	0	0	0	0	0	0	0	0	0
36	Percentage		0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
37													
38	North Dakota	NPISN	790,044,183	245,297,677	12,928,790	176,400,193	269,881,558	689,705	15,847,338	7,298,393	18,549,290	41,965,193	1,186,046
39	Percentage		100.00000%	31.04860%	1.63646%	22.32789%	34.16031%	0.08730%	2.00588%	0.92380%	2.34788%	5.31175%	0.15012%
40													
41	Excluding South Dakota	NPMNR	790,044,183	245,297,677	12,928,790	176,400,193	269,881,558	689,705	15,847,338	7,298,393	18,549,290	41,965,193	1,186,046
42	Percentage		100.00000%	31.04860%	1.63646%	22.32789%	34.16031%	0.08730%	2.00588%	0.92380%	2.34788%	5.31175%	0.15012%
43													
44	Long-Term CWIP Ratio (W/AFDC)	CWIPLT	0	0	0	0	0	0	0	0	0	0	0
45	Percentage		0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
46													
47	Revenue	R10	182,782,835	50,921,629	2,639,772	38,503,051	72,695,877	94,067	3,056,500	1,358,947	2,381,778	10,409,315	721,900
48	Percentage		100.00000%	27.85909%	1.44421%	21.06492%	39.77172%	0.05146%	1.67220%	0.74348%	1.30306%	5.69491%	0.39495%
49													
50	Labor and Related Expense	LRE	63,321,684	25,536,480	1,043,125	15,628,099	16,292,397	43,440	803,575	660,688	1,154,527	2,083,757	75,596
51	Percentage		100.00000%	40.32818%	1.64734%	24.68049%	25.72957%	0.06860%	1.26904%	1.04338%	1.82327%	3.29075%	0.11938%
52													
53	Total O & M Expense	OX	140,267,771	41,803,211	1,938,931	28,321,827	55,321,702	79,756	1,155,006	1,229,621	2,033,490	7,902,568	481,658
54	Percentage		100.00000%	29.80243%	1.38231%	20.19126%	39.44007%	0.05686%	0.82343%	0.87662%	1.44972%	5.63392%	0.34338%
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Volume 3

F. Other Supplemental Information

ANNUAL REPORT 2022

OTTER TAIL CORPORATION

ELECTRIC PLATFORM

Otter Tail Power Company
Electric utility
Headquarters: Fergus Falls, MN
Founded 1907
President, Tim Rogelstad
728 full-time employees
www.otpco.com

MANUFACTURING PLATFORM

BTD Manufacturing, Inc.
Metal fabricator
Headquarters: Detroit Lakes, MN
Aquired 1995
President, Paul Gintner
1,281 full-time employees
www.btdmfg.com

T.O. Plastics, Inc.
Custom plastic parts manufacturer
Headquarters: Clearwater, MN
Aquired 2001
President, Paul Meschke
204 full-time employees
www.toplastics.com

Northern Pipe Products, Inc.
PVC pipe manufacturer
Headquarters: Fargo, ND
Aquired 1995
President, Terry Mitzel
95 full-time employees
www.northernpipe.com

Vinyltech Corporation
PVC pipe manufacturer
Headquarters: Phoenix, AZ
Aquired 2000
President, Terry Mitzel
78 full-time employees
www.vtpipe.com

VISION

We build top-performing companies in a diversified organization with an electric utility as our foundation.

MISSION

We deliver value by building strong electric utility and manufacturing platforms.

FOR OUR SHAREHOLDERS we deliver above-average returns through commercial and operational excellence and growing our businesses.

FOR OUR CUSTOMERS we commit to quality and value in everything we do.

FOR OUR EMPLOYEES we provide an environment of opportunity with accountability where all people are valued and empowered to do their best work.

VALUES

INTEGRITY
We conduct business responsibly and honestly.

SAFETY
We provide safe workplaces and require safe work practices.

PEOPLE
We build respectful relationships and create inclusive environments where all people can thrive.

PERFORMANCE
We strive for excellence, act on opportunity, and deliver on commitments.

COMMUNITY
We improve the communities where we work and live.

OBJECTIVES

GROW our businesses

ACHIEVE operational and commercial excellence

ACHIEVE talent excellence

	2022	2021	PERCENT CHANGE
CONSOLIDATED OPERATIONS ($ in thousands, except per share amounts)			
Operating Revenues	$ 1,460,209	$ 1,196,844	22.0
Net Income	$ 284,184	$ 176,769	60.8
Diluted Earnings per Share	$ 6.78	$ 4.23	60.3
Dividends per Common Share	$ 1.65	$ 1.56	5.8
Return on Average Common Equity	25.6%	19.2%	33.3
Book Value per Common Share	$ 29.24	$ 23.84	22.6
Cash Flow from Operating Activities	$ 389,309	$ 231,243	68.4
Number of Common Shares Outstanding	41,631,113	41,551,524	0.2
Number of Common Shareholders	11,748	12,038	(2.4)
Closing Stock Price	$ 58.71	$ 71.42	(17.8)
Total Return (share price appreciation plus dividends)	(15.5)%	71.3%	n/m
Total Market Value of Common Stock	$ 2,444,163	$ 2,967,610	(17.6)
ELECTRIC PLATFORM ($ in thousands)			
Operating Revenues	$ 549,699	$ 480,321	14.4
Total Retail Electric Sales (MWH)	5,592,368	4,789,879	16.8
Operating Income	$ 113,138	$ 106,964	5.8
Customers	133,414	133,304	0.1
Gross Plant Investment	$ 2,958,311	$ 2,833,371	4.4
Total Assets	$ 2,351,961	$ 2,283,776	3.0
Capital Expenditures	$ 147,869	$ 140,031	5.6
MANUFACTURING PLATFORM ($ in thousands)			
Operating Revenues	$ 910,510	$ 716,523	27.1
Operating Income	$ 293,643	$ 156,874	87.2
Total Assets	$ 372,187	$ 413,609	(10.0)
Capital Expenditures	$ 23,199	$ 31,730	(26.9)

OPERATING REVENUES
↑22%
NET INCOME
↑61%
IN 2022

OPERATING REVENUES
↑14%
NET INCOME
↑10%
IN 2022

OPERATING REVENUES
↑27%
NET INCOME
↑88%
IN 2022

TO OUR SHAREHOLDERS

CHARLES S. MACFARLANE
PRESIDENT AND CEO

A REMARKABLE YEAR

Otter Tail Corporation and its companies experienced unique successes this year. We are delivering value for our employees, customers, and shareholders as we continue building top-performing companies.

Through our combined efforts in 2022, we achieved record financial results. Our diversified business model produced consolidated net income and diluted earnings per share of $284.2 million and $6.78 respectively, compared with $176.8 million and $4.23 in 2021; earnings per share increased 60.3 percent year over year. Our return on equity in 2022 was 25.6 percent.

We have paid dividends on our common stock for 84 years, or 337 consecutive quarters. The dividend yield at December 31, 2022, was 2.8 percent. Our total shareholder return over the five-year period ending December 31, 2022, was 53.0 percent. Our annual indicated dividend per share for 2023 is $1.75, a 6.1 percent increase over our 2022 dividend rate.

At the Edison Electric Institute (EEI) Financial Conference in November 2022, Otter Tail Corporation received the EEI Index Award for the top performing small-capitalization utility for the second year in a row, with a total shareholder return of 64 percent over the five-year period ending September 30, 2022. This award is presented annually to EEI member companies that have achieved the highest total shareholder return in the large-, mid-, and small-capitalization categories.

Our 2022 financial results are highlighted throughout this Annual Report. While financial results alone do not provide the full picture of a corporation's health, they do help demonstrate our commitment to delivering value for our shareholders, our emphasis on consistently meeting customer expectations, and our efforts to ensure every employee can thrive and is positioned for success.

UTILITY EXECUTES ON CAPITAL INVESTMENT PLAN

Otter Tail Power Company again executed on its capital investment plan and benefited from an increase in sales volumes in 2022 to produce earnings of $80.0 million, a 10.4 percent increase from last year. The addition of new customers, high availability at our coal plants, transmission investments, and a successful rate case, as well as excellent recovery efforts following significant storms, contributed to a strong finish to our year. All of this was made possible through noteworthy day-to-day operational excellence. We grew average rate base by 3.1 percent in 2022, primarily through capital investments in energy generation and regional transmission projects.

We continue to work toward a cleaner energy future. Our target is to reduce carbon emissions from our owned generation resources approximately 50 percent from 2005 levels by 2025 and 97 percent by 2050—while keeping residential rates among the lowest in the nation. Additionally, our goal is for our owned and contracted energy generation to be more than 50 percent renewable by 2025.

We began construction on Hoot Lake Solar, a $60 million, 49-megawatt (MW) solar farm, in May. With proximity to an existing transmission interconnection from our retired coal-fired Hoot Lake Plant, the project allows us to add renewable energy to the grid without investing in additional, costly infrastructure. We began generating electricity at Hoot Lake Solar in early 2023 and expect to be fully operational by midyear, with 100 percent of the costs and benefits allocated to Minnesota customers.

In November the Minnesota Public Utilities Commission granted our request to amend our Integrated Resource Plan (IRP) procedural schedule. Otter Tail Power filed its IRP in September 2021. In our original plan, we requested authority to add on-site fuel storage at Astoria Station in South Dakota, to add

150 MW of solar generation at a location yet to be determined, and to commence the process to withdraw from our 35 percent ownership interest in Coyote Station in North Dakota by December 31, 2028. Since that filing, we have seen significant changes in the energy industry, including the Midcontinent Independent System Operator's (MISO) new seasonal resource adequacy construct and significant increase in winter and spring planning reserve margins, along with the enactment of the Inflation Reduction Act—which together drive the need to update our IRP. We plan to file an updated plan in March 2023 given these new circumstances. We will maintain the original procedural schedule as it relates to adding on-site fuel storage at Astoria Station, which is pictured on the cover of this report.

In July the MISO Board of Directors approved $10.3 billion in transmission projects focused on its Midwest Subregion. These projects are the first group of four in MISO's Long-Range Transmission Planning process that aims to integrate new generation resources—as outlined in MISO member and state plans—and increase resilience in the face of severe weather events. Two transmission projects, the Jamestown-Ellendale project and the Big Stone South-Alexandria project are in our service area, and Otter Tail Power will be a joint owner in each project. We estimate our total capital investment in these projects to be $390 million.

We also continued plans for installing Advanced Metering Infrastructure (AMI). We will start with a pilot program in 2023 and plan to finish full deployment in 2024, upgrading more than 174,000 electric meters with meters that enable two-way communication with our systems. AMI lays the groundwork for improved outage response and communication and provides the ability to remotely find the location of an outage, read meters, and turn meters on and off. When combined with systems we have in place today, including an Outage Management System and telephone-based Integrated Voice Response, customers will have more visibility into their energy use and account information as we more efficiently and effectively meet their electric service needs.

In January 2023 we purchased the Ashtabula III wind farm, located in eastern North Dakota. We have purchased wind-generated electricity from Ashtabula III since 2013 through a power purchase agreement, but owning the facility provides a lower cost alternative than maintaining the purchased power arrangement. The purchase added 62.4 MW of nameplate capacity to our owned generation assets.

Thanks to resilient and hard-working employees, Otter Tail Power continues its long tradition of operational excellence while providing customers with a safe, reliable, and low-cost essential service. This was highlighted in January 2023, when EEI announced at its board meeting that Otter Tail Power was selected as one of 18 recipients of EEI's Emergency Recovery Award for our outstanding restoration efforts during and after the storm that hit parts of our service area on May 12, 2022. EEI's Emergency Recovery Award recognizes member companies that put forth outstanding efforts to restore service promptly to the public following a storm or natural disaster.

We will continue to make system investments to meet customers' expectations, manage operating and maintenance costs, transition to a cleaner energy future, and improve reliability and safety.

MANUFACTURING PLATFORM DELIVERS OUTSTANDING FINANCIAL RESULTS

Northern Pipe Products and Vinyltech, our PVC pipe manufacturing companies that comprise our Plastics Segment, delivered extraordinary financial results in 2022, producing record earnings of $195.4 million. Our employees effectively capitalized on unique industry supply and demand conditions while navigating volatile input costs, supply challenges, and unpredictable customer demand. We currently expect these industry conditions to normalize throughout 2023.

We have commenced work on a facility expansion and site improvement plan at our Vinyltech facility in Phoenix, Arizona. The project will provide an organic growth opportunity for our business, adding increased raw material storage and handling capabilities and additional manufacturing capacity at this location. We currently anticipate the project will be complete by the end of 2024.

BTD, our contract metal fabricator, produced earnings of $16.6 million in 2022, a 13.0 percent increase from 2021. Strong customer demand across most end markets drove the increase in earnings and more than offset a decline in scrap metal revenues as steel prices receded from recent highs. Our BTD employees were challenged by, and effectively navigated, volatile steel markets, unpredictable customer demand, workforce challenges, and persistent inflationary pressures while maintaining excellent quality and on-time delivery.

T.O. Plastics, our plastics thermoforming manufacturer, benefited from robust customer demand for horticulture products to produce earnings growth of 74 percent compared to last year. Improved price realization, which more than offset inflationary cost pressures, also contributed to earnings growth in 2022.

Both BTD and T.O. Plastics continue to do an excellent job managing through the current inflationary environment and supply chain disruptions while meeting strong customer demand.

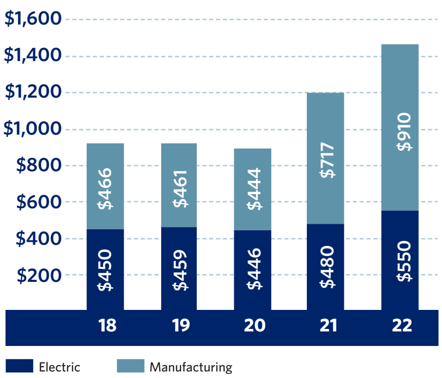
FOCUSED ON OUR SHARED SUCCESS

We are in unique times and our employees are responding in extraordinary ways. Our vision, mission, and values—which we refreshed in 2022—guide us toward fulfilling our strategic objectives to grow our businesses and achieve operational, commercial, and talent excellence.

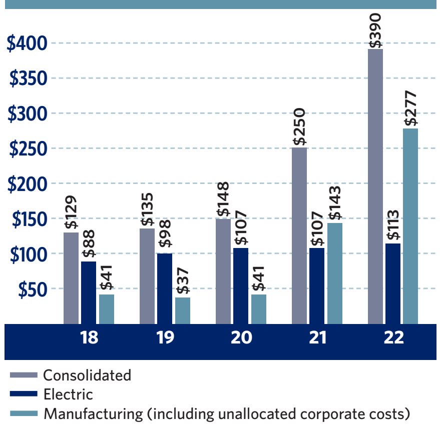
We have a strong and steady future. Thank you to our employees for everything you do to ensure our top performance. And thank you to our customers and shareholders for your confidence in our ongoing success.

Charles S. MacFarlane
President and Chief Executive Officer

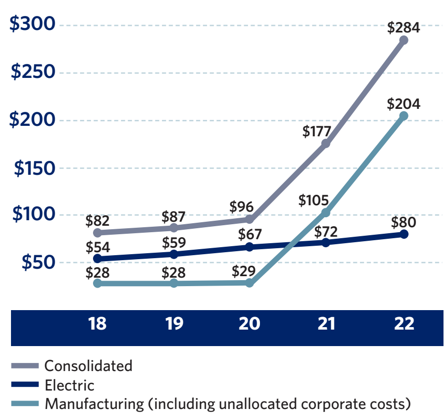
REVENUE BY PLATFORM (millions)



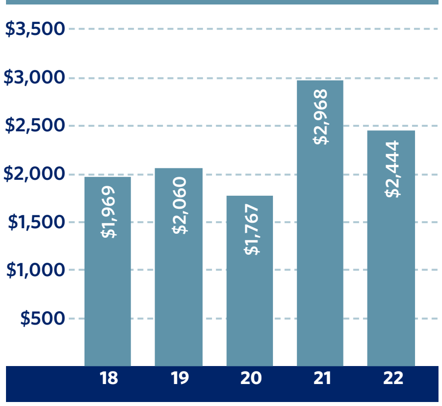
OPERATING INCOME BY PLATFORM (millions)



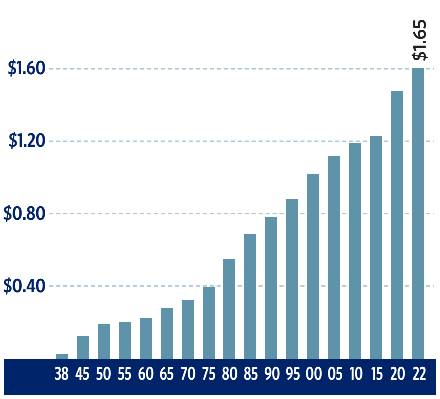
NET INCOME BY PLATFORM (millions)



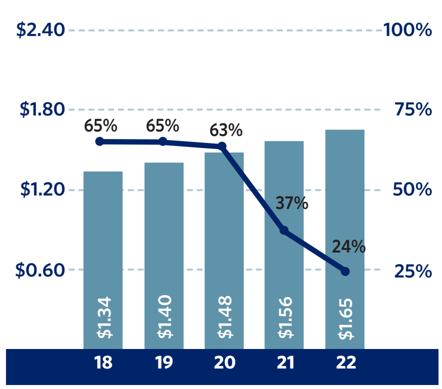
MARKET CAPITALIZATION (millions)



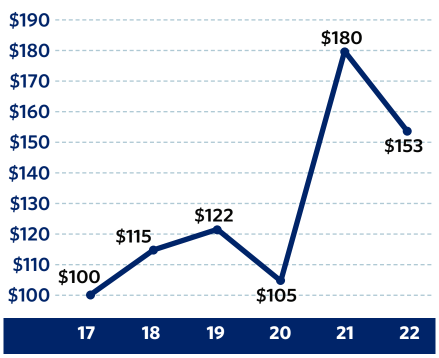
DIVIDEND PAYMENT HISTORY



DIVIDEND PAYOUT RATIO



GROWTH OF $100 INVESTMENT IN OTTER TAIL COMMON STOCK MADE DECEMBER 31, 2017 (with dividends reinvested)



Total shareholder return has grown at a compounded annual rate of 53.0 percent over the past five years, and we have paid dividends on common stock for 84 years, or 337 consecutive quarters.

SELECTED COMMON SHARE DATA	2022	2021	2020	2019	2018	2017
Market Price:						
High	$ 82.46	$ 71.71	$ 56.90	$ 57.74	$ 51.88	$ 48.65
Low	$ 52.60	$ 39.35	$ 30.95	$ 45.94	$ 39.00	$ 35.65
Common Price/Earnings Ratio:						
High	12.2	17.0	24.3	26.6	25.2	26.7
Low	7.8	9.3	13.2	21.2	18.9	19.6
Book Value Per Common Share	$ 29.24	$ 23.84	$ 21.00	$ 19.46	$ 18.38	$ 17.62

SELECTED DATA AND RATIOS	2022	2021	2020	2019	2018	2017
Interest Coverage Before Taxes	10.8x	6.5x	4.1x	4.1x	4.0x	4.3x
Effective Income Tax Rate (percent)	21	17	17	17	15	27
Return on Capitalization Including Short-Term Debt (percent)	15.6	11.6	7.6	8.0	8.4	7.9
Return on Average Common Equity (percent)[1]	25.6	19.2	11.6	11.6	11.5	10.6
Dividend Payout Ratio (percent)	24	37	63	65	65	70
Cash Realization[2]	1.37	1.31	2.21	2.13	1.74	2.40
Capital Ratio (percent):						
Short Term and Long-Term Debt	40.6	46.3	49.3	47.1	45.5	46.4
Common Equity	59.4	53.7	50.7	52.9	54.5	53.6
	100.0	100.0	100.0	100.0	100.0	100.0

(1) Earnings available for common shares divided by the 13-month average of month-end common equity balances.
(2) Net cash provided by operating activities divided by net income.

SELECTED ELECTRIC OPERATING DATA	2022	2021	2020	2019	2018	2017
Revenues (thousands)						
Residential	$ 143,888	$ 135,361	$ 127,260	$ 131,988	$ 125,045	$ 116,990
Commercial and Industrial	318,494	262,408	254,951	267,125	256,331	251,092
Other Retail	7,918	7,715	7,311	7,365	6,875	6,849
Total Retail	470,300	405,484	389,522	406,478	388,251	374,931
Sales for Resale	18,539	17,936	4,857	5,007	7,735	5,173
Other Electric	60,860	56,901	51,751	47,612	54,269	54,433
Total Electric	$ 549,699	$ 480,321	$ 446,130	$ 459,097	$ 450,255	$ 434,537
Kilowatt-hours Sold (thousands)						
Residential	1,309,249	1,241,951	1,266,232	1,303,317	1,321,132	1,243,194
Commercial and Industrial	4,224,190	3,489,342	3,446,743	3,598,002	3,590,651	3,506,707
Other	58,928	58,586	63,712	67,770	65,177	65,083
Total Retail	5,592,368	4,789,879	4,776,687	4,969,089	4,976,960	4,814,984
Sales for Resale	267,184	420,044	236,528	198,569	271,840	203,397
Total	5,859,552	5,209,923	5,013,215	5,167,658	5,248,800	5,018,381
Annual Retail Kilowatt-hour Sales Growth (percent)	16.8	0.3	(3.9)	(0.2)	3.4	1.4
Heating Degree Days[3]	7,122	5,794	6,174	7,240	6,904	5,931
Cooling Degree Days[4]	531	704	534	392	567	380
Average Revenue Per Kilowatt-hour						
Residential	10.99¢	10.90¢	10.05¢	10.13¢	9.46¢	9.41¢
Commercial and Industrial	7.54¢	7.52¢	7.40¢	7.42¢	7.14¢	7.16¢
All Retail	8.41¢	8.47¢	8.15¢	8.18¢	7.80¢	7.79¢
Customers						
Residential	103,950	103,835	103,658	103,328	104,242	104,038
Commercial and Industrial	27,578	27,582	27,468	27,348	27,223	27,123
Other	1,886	1,887	1,906	1,911	993	995
Total Electric Customers	133,414	133,304	133,032	132,587	132,458	132,156
Residential Sales						
Average Kilowatt-hours Per Customer[5]	12,556	11,812	12,186	12,689	12,740	11,962
Average Revenue Per Residential Customer	$ 1,412	$ 1,294	$ 1,250	$ 1,289	$ 1,226	$ 1,161
Depreciation Reserve (thousands)						
Electric Plant in Service	$ 2,844,379	$ 2,758,445	$ 2,531,312	$ 2,212,884	$ 2,019,721	$ 1,981,018
Depreciation Reserve	$ 859,988	$ 817,302	$ 778,988	$ 731,110	$ 699,642	$ 662,431
Reserve to Electric Plant (percent)	30.2	29.6	30.8	33.0	34.6	33.4
Composite Depreciation Rate (percent)	2.40	2.67	2.63	2.81	2.76	2.74
Peak Demand and Net Generating Capability						
Peak Demand (kilowatts)	987,628	865,120	844,929	923,962	911,726	916,522
Net Generating Capability (kilowatts):[6]						
Steam	406,200	406,800	548,100	548,700	548,500	547,600
Wind	288,000	288,000	288,000	138,000	138,000	138,000
Combustion Turbines	343,700	352,500	107,900	105,100	106,200	109,900
Hydro	2,500	2,600	2,500	2,800	2,900	2,800
Total Owned Generating Capability	1,040,400	1,049,900	946,500	794,600	795,600	798,300

Notes:

(3) Based on 55 degrees Fahrenheit base and average method.
(4) Based on 65 degrees Fahrenheit base and average method.
(5) Based on average number of customers during the year.
(6) Measurement of net dependable capacity.

EXECUTIVE LEADERSHIP

CHARLES S. MACFARLANE
President and
Chief Executive Officer

KEVIN G. MOUG
Senior Vice President and
Chief Financial Officer

TIMOTHY J. ROGELSTAD
Senior Vice President,
Electric Platform;
President, Otter Tail
Power Company

JOHN S. ABBOTT
Senior Vice President,
Manufacturing Platform;
President, Varistar

PAUL L. KNUTSON
Vice President,
Human Resources

JENNIFER O. SMESTAD
Vice President,
General Counsel,
and Corporate Secretary

STEPHANIE A. HOFF
Director,
Corporate Communications

DIRECTORS

NATHAN I. PARTAIN
Chairman of the Board
League City, Texas
Retired President and
Chief Investment Officer,
Duff & Phelps Investment
Management Co.

CHARLES S. MACFARLANE
Fergus Falls, Minnesota
President and Chief
Executive Officer,
Otter Tail Corporation;
Chief Executive Officer,
Otter Tail Power Company

KAREN M. BOHN
A/CG
Edina, Minnesota
President, Galeo Group, LLC
(management consulting firm)

JEANNE H. CRAIN
A/C
Minneapolis, Minnesota
President and Chief Executive Officer,
Bremer Financial Corporation

JOHN D. ERICKSON
Fergus Falls, Minnesota
Advisor to ECJV Holding, LLC;
Former President and
Chief Executive Officer,
Otter Tail Corporation
(utility and diversified businesses)

STEVEN L. FRITZE
A/CG
Eagan, Minnesota
Retired Chief Financial
Officer, Ecolab Inc.
(diversified manufacturing)

DR. KATHRYN O. JOHNSON
C/CG
Hill City, South Dakota
Owner and Principal, Johnson
Environmental Concepts
(geochemical consulting firm)

DR. MICHAEL E. LEBEAU
C/CG
Bismarck, North Dakota
System Vice President and
Chief Administrative Officer
Health Services Division
Sanford Health

MARY E. LUDFORD
A/CG
Chicago, Illinois
Retired Chief Audit Executive and
Deputy Chief Security Officer,
Exelon Corporation
(regulated transmission and
distribution utilities)

JAMES B. STAKE
A/C
Edina, Minnesota
Retired Executive Vice President,
Enterprise Services, 3M Company
(diversified manufacturing)

THOMAS J. WEBB
A/C
Richland, Michigan
Advisor, Retired Vice President
and Chief Financial Officer,
CMS Energy Corporation
(gas and electric utility)

Committees:
A—Audit
C—Compensation and Human Capital Management
CG—Corporate Governance

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2022 or

☐ **Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission File Number **0-53713**

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

Minnesota	**27-0383995**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
215 South Cascade Street, Box 496, Fergus Falls, Minnesota	**56538-0496**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **866-410-8780**

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares, par value $5.00 per share	OTTR	The Nasdaq Stock Market LLC

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T 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 or a smaller reporting 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. (Check one):

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. ☑

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

As of June 30, 2022, the aggregate market value of common stock held by non-affiliates was **$2,689,579,964**.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **41,631,763 Common Shares ($5 par value) as of January 31, 2023**.

DOCUMENTS INCORPORATED BY REFERENCE

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

TABLE OF CONTENTS

DEFINITIONS

The following abbreviations or acronyms are used in the text.

ACE	Affordable Clean Energy	LIBOR	London Interbank Offered Rate
AFUDC	Allowance for Funds Used During Construction	LSA	Lignite Sales Agreement
AMDT	Advanced Meter and Distribution Technology	Merricourt	Merricourt Wind Energy Center
ARO	Asset Retirement Obligation	MISO	Midcontinent Independent System Operator
ARP	Alternative Revenue Program	MPUC	Minnesota Public Utilities Commission
Astoria	Astoria Station	NAV	Net Asset Value
BTD	BTD Manufacturing, Inc.	NDDEQ	North Dakota Department of Environmental Quality
CCMC	Coyote Creek Mining Company, L.L.C.	NDPSC	North Dakota Public Service Commission
CDD	Cooling Degree Day	NERC	North American Electric Reliability Corporation
CIP	Conservation Improvement Program	Northern Pipe	Northern Pipe Products, Inc.
CO_2	Carbon dioxide	OTC	Otter Tail Corporation
COSO	Committee of Sponsoring Organizations of the Treadway Commission	OTP	Otter Tail Power Company
EEI	Edison Electric Institute	Paris Agreement	United Nations Framework Convention on Climate Change
EPA	Environmental Protection Agency	PFAS	Polyfluoroalkyl substances
ERISA	Employee Retirement Income Security Act of 1974	PIR	Phase-in Rider
ESSRP	Executive Survivor and Supplemental Retirement Plan	PSLRA	Private Securities Litigation Reform Act of 1995
FCA	Fuel Clause Adjustment	PTCs	Production tax credits
FERC	Federal Energy Regulatory Commission	PVC	Polyvinyl chloride
GCR	Generation Cost Recovery Rider	RHR	Regional Haze Rule
GHG	Greenhouse Gas	ROE	Return on equity
HDD	Heating Degree Day	RRR	Renewable Resource Rider
ISO	Independent System Operator	SDPUC	South Dakota Public Utilities Commission
IRA	Inflation Reduction Act	SEC	Securities and Exchange Commission
IRP	Integrated Resource Plan	SIP	State implementation plans
ITCs	Investment Tax Credits	SOFR	Secured Overnight Financing Rate
kV	kiloVolt	T.O. Plastics	T.O. Plastics, Inc.
kW	kiloWatt	TCR	Transmission Cost Recovery Rider
kwh	kilowatt-hour	Vinyltech	Vinyltech Corporation

WHERE TO FIND MORE INFORMATION

We make available free of charge at our website (www.ottertail.com) our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy and information statements, Forms 3, 4 and 5 filed on behalf of directors and executive officers and any amendments to these 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 such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). These reports are also available on the SEC's website (www.sec.gov). Information on our and the SEC's websites is not deemed to be incorporated by reference into this report on Form 10-K.

FORWARD-LOOKING INFORMATION

This report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the PSLRA). When used in this Form 10-K and in future filings by the Company with the SEC, in the Company’s press releases and in oral statements, words such as “anticipate,” “believe,” “could,” “estimate,” “expect,” "future," "goal," “intend,” "likely," “may,” “outlook,” “plan,” “possible,” “potential,” "predict," "probable," "projected," “should,” "target," “will,” “would” or similar expressions are intended to identify forward-looking statements within the meaning of the PSLRA. Such statements are based on current expectations and assumptions and entail various risks and uncertainties that could cause actual results to differ materially from those expressed in such forward-looking statements. Such risks and uncertainties include the various factors set forth in Item 1A. Risk Factors of this report on Form 10-K and in our other SEC filings.

PART I

ITEM 1. BUSINESS

Otter Tail Corporation (OTC) has interests in diversified operations that include an electric utility and manufacturing and plastic pipe businesses with corporate offices located in Fergus Falls, Minnesota and Fargo, North Dakota.

We classify our five operating companies into three reportable segments consistent with our business strategy and management structure. The following table depicts our three segments and the subsidiary entities included within each segment:

ELECTRIC SEGMENT	MANUFACTURING SEGMENT	PLASTICS SEGMENT
Otter Tail Power Company (OTP)	BTD Manufacturing, Inc. (BTD)	Northern Pipe Products, Inc. (Northern Pipe)
	T.O. Plastics, Inc. (T.O. Plastics)	Vinyltech Corporation (Vinyltech)

Electric includes the generation, purchase, transmission, distribution and sale of electric energy in western Minnesota, eastern North Dakota and northeastern South Dakota. OTP, our largest operating subsidiary and primary business since 1907, serves more than 133,000 customers in more than 400 communities across a predominantly rural and agricultural service territory.

Manufacturing consists of businesses in the following manufacturing activities: contract machining; metal parts stamping; fabrication and painting; and production of plastic thermoformed horticultural containers, life science and industrial packaging, material handling components and extruded raw material stock. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the western half of the United States and Canada.

Throughout the remainder of this report, we use the terms "Company", "us", "our", or "we" to refer to OTC and its subsidiaries collectively. We will also refer to our Electric, Manufacturing and Plastics segments and our individual subsidiaries as indicated above.

INVESTMENT AND GROWTH STRATEGY

We maintain a moderate risk profile by investing in rate base growth opportunities in our Electric segment and organic growth opportunities in our Manufacturing and Plastics segments (collectively, our manufacturing platform). This strategy and risk profile are designed to provide a more predictable earnings stream, maintain our credit quality and preserve our ability to fund our dividend payments.

Our long-term focus remains on executing our strategy to grow our business and achieving operational, commercial and talent excellence to strengthen our position in the markets we serve. We remain confident in our ability to achieve a compounded annual growth rate in earnings per share in the range of five to seven percent using 2024 as the base year. We currently expect to see elevated earnings per share from our manufacturing platform into 2023 with our earnings mix expected to move to approximately 65% from our Electric segment and 35% from our manufacturing platform beginning in 2024. We expect our earnings growth beyond 2024 to be driven by rate base investments in our Electric segment and from existing capacities and planned investments within our Manufacturing and Plastics segments.

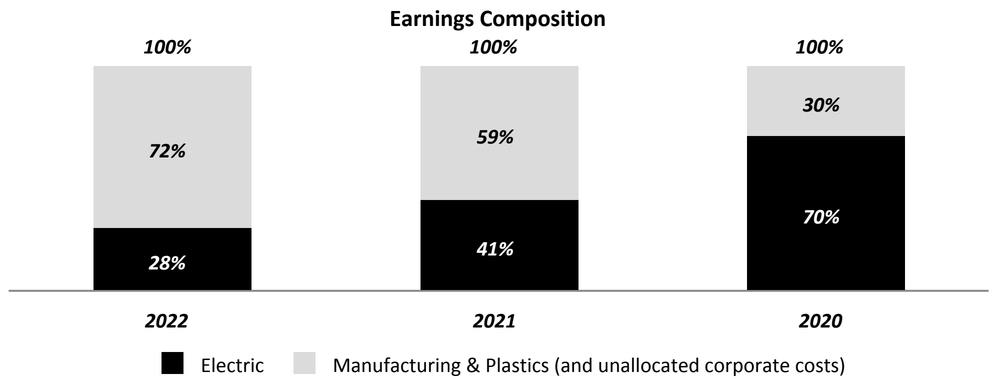
Over the past two years, we delivered earnings growth well in excess of our five to seven percent target due to unique industry conditions within the PVC pipe industry which led to extraordinary revenue, earnings and cash flow growth in our Plastics Segment.

We will continue to review our business portfolio to identify additional opportunities to improve our risk profile, enhance our credit metrics and generate additional sources of cash to support the organic growth opportunities in our Electric, Manufacturing, and Plastics segments. We will also evaluate opportunities to allocate capital to potential acquisitions. We are a committed long-term owner and do not acquire companies in pursuit of short-term gains. However, we will divest businesses which no longer fit into our strategy and risk profile over the long term.

We maintain a set of criteria used in evaluating the strategic fit of our operating businesses. The operating company should:

- Maintain a minimum level of net earnings and a return on invested capital in excess of the Company’s weighted-average cost of capital,
- Have a strategic differentiation from competitors and a sustainable cost advantage,
- Operate within a stable and growing industry and be able to quickly adapt to changing economic cycles, and
- Have a strong management team committed to operational and commercial excellence.

Our actual mix of earnings for the years ended December 31, 2022, 2021, and 2020 was as follows:



HUMAN CAPITAL

Our employees are a critical resource and an integral part of our success. We strive to provide an environment of opportunity and accountability where people are valued and empowered to do their best work. We are focused on the health and safety of our employees and creating a culture of inclusion, excellence and learning. Our human capital management efforts include monitoring various metrics and objectives associated with i) employee safety, ii) workforce stability, iii) management and workforce demographics, including gender, racial and ethnic diversity, iv) leadership development and succession planning and v) productivity. We have established the following programs in furtherance of these efforts:

Safety - Safety is one of our core values. In managing our business, we focus on the safety of our employees and have implemented safety programs and management practices to promote a culture of safety. Safety is also a metric used and evaluated in determining annual incentive compensation. We continually monitor the Occupational Safety and Health Administration (OSHA) Total Recordable Incident Rate (number of work-related injuries per 100 employees for a one-year period) and Lost Time Incident Rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). New cases are reported and evaluated for corrective action during monthly safety meetings attended by safety professionals at all locations. Our 2022 Total Recordable Incident Rate was 2.08, compared to 1.86 in 2021 and our Lost Time Incident Rate was 0.49, compared to 0.57 in 2021. In both 2022 and 2021 these rates were favorable when compared to the rates of our peers.

Employee and Leadership Development, Succession Planning and Training Programs - We invest in leadership development for various levels of employees, management and leaders throughout the Company to build enterprise-wide understanding of our culture, strategy and processes. Annual succession planning, individual development planning, mentoring, and supervisory and leadership development programs all play a role in ensuring a capable leadership team now and in the future. Our skill progression and technical training programs help to retain a stable and skilled workforce.

Workforce Stability - Recruiting, retaining and developing employees is an important factor in our continued success and growth. We regularly evaluate our recruiting programs, employee retention and turnover rates.

Employee Engagement - To enhance the effectiveness of our workforce and to help our companies continue to be places where our employees choose to work and thrive, we have undertaken a multi-year series of employee engagement surveys. We use the feedback to help shape the employee programs of our organization.

Diversity, Equity, and Inclusion - We expect, and are committed to, diversity, equity and inclusion as part of who we are, what we value and how we achieve individual, business and community success. We hold every employee accountable for their behavior in maintaining a workplace free of discrimination and harassment. We have implemented education initiatives for all employees, aimed at inclusive leadership and a respectful workplace, focused on identities and culture, unconscious bias, the power of diverse teams and culturally sensitive conversations. We have implemented initiatives to improve upon our demographic profile, including revised hiring processes and a commitment to diverse interview slates.

Code of Business Ethics - We require employees to complete training on several topics associated with our code of business ethics to reinforce our commitment to compliance with laws, regulations and values that guide who we are and how we do business.

As of December 31, 2022, we employed 2,422 full-time employees as shown in the table below:

Segment/Organization	*Employees*
Electric Segment	
OTP [1]	728
Manufacturing Segment	
BTD	1,281
T.O. Plastics	204
Segment Total	1,485
Plastics Segment	
Northern Pipe	95
Vinyltech	78
Segment Total	173
Corporate	36
Total	2,422

[1] Includes all full-time employees of Otter Tail Power Company, including employees working at jointly-owned facilities. Labor costs associated with employees working at jointly-owned facilities are allocated to each of the co-owners based on their ownership interest.

At December 31, 2022, 354 employees of OTP were represented by local unions of the International Brotherhood of Electrical Workers under two separate collective bargaining agreements expiring on August 31, 2023 and October 31, 2023. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good. None of the employees of our other operating companies are represented by local unions.

The demographics of our workforce, including our Board of Directors, as of December 31, 2022 was as follows:

	2022		*2021*	
	% Female	*% Racially and Ethnically Diverse*	*% Female*	*% Racially and Ethnically Diverse*
Board of Directors[1]	36 %	9 %	20 %	10 %
CEO Direct Reports	33 %	— %	33 %	— %
Management	33 %	7 %	22 %	4 %
Non-Management Employees	16 %	19 %	17 %	19 %

[1] 2022 includes the new directors appointed to our Board effective January 1, 2023.

ELECTRIC

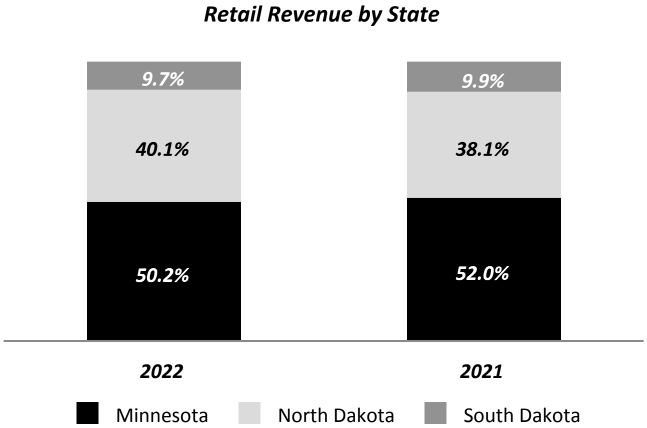
Contribution to Operating Revenues: 38% (2022), 40% (2021), 50% (2020)

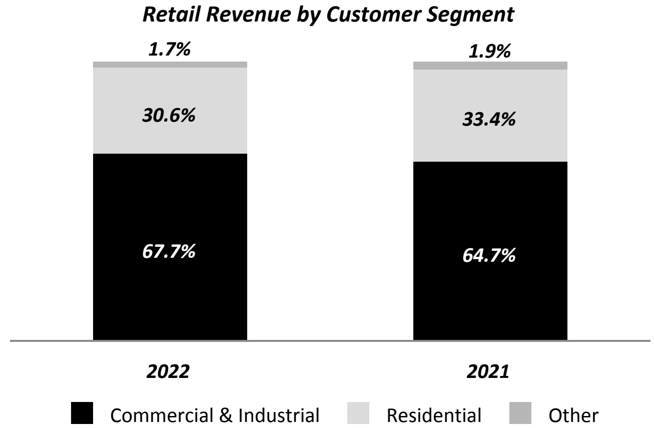
OTP, headquartered in Fergus Falls, Minnesota, is a vertically integrated, regulated utility with generation, transmission and distribution facilities to serve its more than 133,000 residential, commercial and industrial customers in a service area encompassing approximately 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota.

CUSTOMERS

Our service territory is predominantly rural and agricultural and includes over 400 communities, most of which have populations of less than 10,000. While our customer base includes relatively few large customers, sales to commercial and industrial customers are significant, with one industrial customer accounting for 11% and 10%, respectively, of segment operating revenues for the years ended December 31, 2022 and 2021.

The following charts summarize our retail electric revenues by state and by customer segment for the years ended December 31, 2022 and 2021:





In addition to retail revenue, our Electric segment also generates operating revenues from the transmission of electricity for others over the transmission assets we wholly or jointly own with other transmission service providers, and from the sale of electricity we generate and sell into the wholesale electricity market.

COMPETITIVE CONDITIONS

Retail electric sales are made to customers in assigned service territories. As a result, most retail customers do not have the ability to choose their electric supplier. Competition is present in some areas from municipally owned systems, rural electric cooperatives and, in certain respects, from on-site generators and co-generators. Electricity also competes with other forms of energy.

Competition also arises from customers supplying their own power through distributed generation, which is the generation of electricity on-site or close to where it is needed in small facilities designed to meet local needs. Distributed energy resources can include combined heat and power, solar photovoltaic, wind, battery storage, thermal storage and demand-response technologies.

The degree of competition may vary from time to time depending on relative costs and supplies of other forms of energy and advances in technology. Irrespective of the competitive environment, we are focused on providing value to our customers and ensuring our retail rates remain among the lowest in the region and in the nation.

The following table presents our average retail rate per kilowatt-hour (kwh) by customer class and in total for the years ended December 31, 2022 and 2021:

Revenue per kwh	***2022***	***2021***
Residential	10.99 ¢	10.90 ¢
Commercial & Industrial	7.54 ¢	7.52 ¢
Total Retail	8.41 ¢	8.47 ¢

Wholesale electricity markets are competitive under the Federal Energy Regulatory Commission (FERC) open access transmission tariffs, which require utilities to provide nondiscriminatory access to all wholesale users. In addition, the FERC has established a competitive process for the construction and operation of certain new electric transmission facilities whereby electric transmission providers, including the Midcontinent Independent System Operator, Inc. (MISO), of which OTP is a member, are required to remove from their tariffs a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. The FERC is contemplating potential reforms for electric regional transmission planning, cost allocation and generator interconnection processes. While the ultimate regulatory outcome is uncertain at this time, changes to the regulatory framework could impact future transmission investments.

Franchises

OTP has franchises to operate as an electric utility in substantially all of the incorporated municipalities it serves. Franchise rights generally require periodic renewal. No franchises are required to serve unincorporated communities in any of the three states OTP serves.

GENERATION AND PURCHASED POWER

OTP primarily relies on company-owned generation, supplemented by power purchase agreements, to supply the energy to meet our customer needs. Wholesale market purchases and sales of electricity are used as necessary to balance supply and demand. Our mix of owned generation and wholesale market energy purchases to meet customer demand are impacted by wholesale energy prices and the relative cost of each energy source.

As of December 31, 2022, OTP’s wholly- or jointly-owned plants and facilities, as well as in place power purchase agreements, and their dependable kilowatt (kW) capacity were:

	Capacity / Purchased Power in kW
Owned Generation:	
Baseload Plants	
Big Stone Plant[(1)]	**258,000**
Coyote Station[(2)]	**148,200**
Total Baseload Plants	**406,200**
Combustion Turbine and Small Diesel Units	
Astoria Station	**242,200**
All Other	**101,500**
Total Combustion Turbine and Small Diesel Units	**343,700**
Owned Wind Facilities (rated at nameplate)	
Merricourt Wind Energy Center	**150,000**
Luverne Wind Farm	**49,500**
Ashtabula Wind Center	**48,000**
Langdon Wind Center	**40,500**
Total Owned Wind Facilities	**288,000**
Hydroelectric Facilities	**2,500**
Total Owned Generation Capacity	**1,040,400**
Power Purchase Agreements:	
Purchased Wind Power (rated at nameplate and greater than 2,000 kW)	
Ashtabula Wind III[(3)]	**62,400**
Edgeley	**21,000**
Langdon	**19,500**
Total Purchased Wind	**102,900**
Total Generating Capacity	**1,143,300**

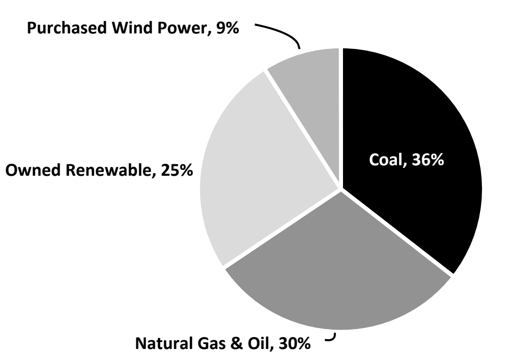
(1) Reflects OTP's 53.9% ownership percentage of jointly-owned facility.

(2) Reflects OTP's 35.0% ownership percentage of jointly-owned facility.

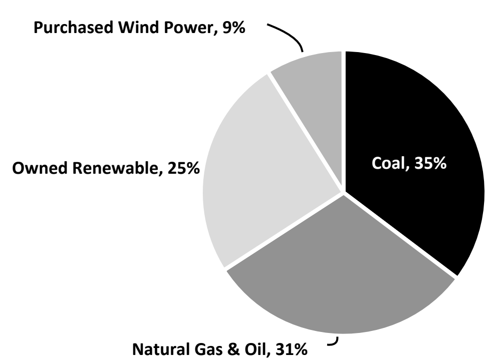
(3) OTP acquired the assets of the Ashtabula III wind farm on January 3, 2023.

The following charts summarize the percentage of our generating capacity by source, including owned and jointly-owned facilities and through power purchase arrangements, as of December 31, 2022 and 2021:

Generating Capacity - December 31, 2022



Generating Capacity - December 31, 2021

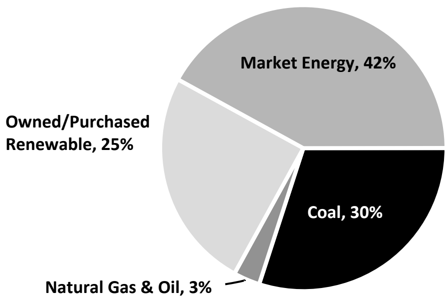


Under MISO requirements, OTP is required to provide sufficient capacity through wholly- or jointly-owned generating capacity or power purchase agreements to meet its monthly weather-normalized forecast demand, plus a reserve obligation.

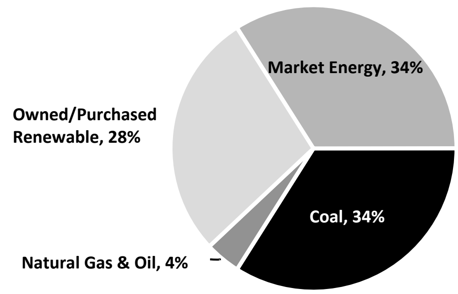
On August 31, 2022, FERC issued an order to approve MISO's proposal to revise its resource adequacy requirement, including the adoption of a seasonal resource adequacy construct rather than a single requirement based on a summer peak. MISO proposed the seasonal adequacy construct to address significant increases in emergency declarations that occur throughout the year, driven by factors including declining excess reserve margin, generation retirements, reliance on intermittent resources and outages resulting from extreme weather events. These new provisions will be implemented in the 2023/2024 planning year. Under the new seasonal resource adequacy construct, the seasonal reserve margin requirements deviate significantly from MISO’s 2022/2023 annual planning reserve margin requirements. For planning year 2022/2023, the last year under the annual construct, our required planning reserve margin was 8.7%. For planning year 2023/2024, under the new seasonal construct, our planning reserve margin requirements range between 7.4% and 25.5%, depending on the season.

The following charts summarize the percentage of retail kwh sold by source during the years ended December 31, 2022 and 2021:

Retail kwh Sold by Source - Year Ended December 31, 2022



Retail kwh Sold by Source - Year Ended December 31, 2021



Capacity Retirements and Additions

Hoot Lake Plant, our 142-megawatt coal-fired power plant in Fergus Falls, Minnesota was retired in mid-2021.

As part of our investment plan to meet our future energy needs, the following significant projects are at various stages of planning and construction or have been recently completed:

Merricourt Wind Energy Center (Merricourt) is a 150-megawatt wind farm located in southeastern North Dakota. The facility was placed into commercial operation in December 2020, with a total cost of approximately $260 million.

Astoria Station Natural Gas Plant (Astoria) is a 245-megawatt simple cycle natural gas combustion turbine generation facility near Astoria, South Dakota. The facility was placed into commercial operation in February 2021, with a total cost of approximately $160 million.

Hoot Lake Solar is a 49-megawatt solar farm under construction on and around our Hoot Lake Plant property in Fergus Falls, Minnesota, with an anticipated cost of approximately $60 million. We anticipate the facility will be in commercial operation by the end of 2023.

Ashtabula III Wind Farm is a 62-megawatt wind farm located in eastern North Dakota. The facility was purchased for approximately $50 million in January 2023. Prior to the purchase of the wind farm assets, we were purchasing the wind-generated electricity from the wind farm pursuant to a power purchase agreement.

ENERGY TRANSITION

OTP is committed to transitioning to a lower-carbon and increasingly clean energy future, while maintaining affordable and reliable electricity to serve our customers. We have developed the following goals in furtherance of our efforts to support the energy transition:

Own or purchase energy generation that's **more than 50% renewable by 2025**.

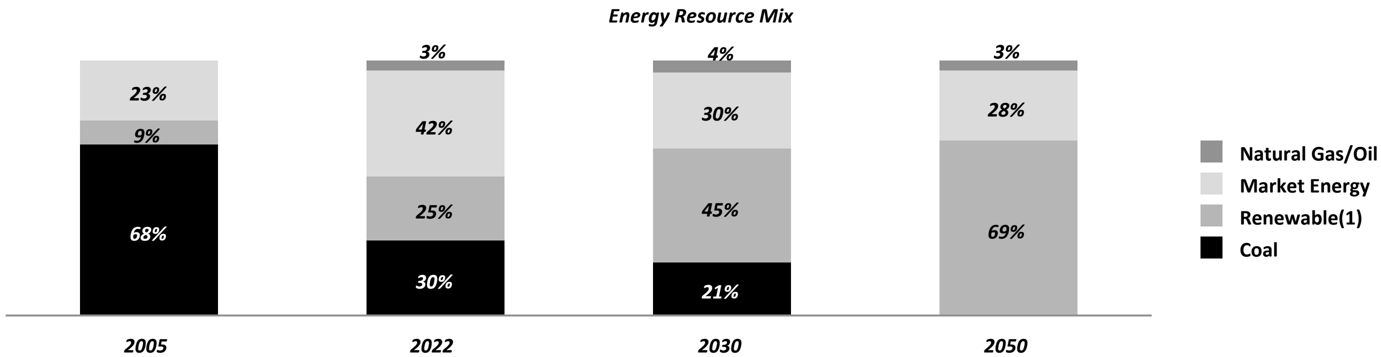
Reduce carbon emissions from owned generation resources **50% by 2025** from 2005 levels.

Reduce carbon emissions from owned generation resources **97% by 2050** from 2005 levels.

To date, we have undertaken numerous initiatives to reduce our carbon footprint and mitigate greenhouse gas (GHG) emissions in the process of generating electricity for our customers. Our initiatives include increasing the efficiency of our plants, retiring Hoot Lake Plant, adding renewable energy to our resource mix and sponsoring energy conservation programs.

From 2005 through 2022, we have reduced our carbon dioxide (CO_2) emissions approximately 43% and increased the amount of renewable generation resources we own or purchase through power purchase agreements by approximately 370-megawatts. Our future resource plans to deliver affordable, reliable, and increasingly clean energy to our customers include the addition of 49-megawatts of solar energy from Hoot Lake Solar in 2023 and repowering various wind farm assets to increase their efficiency and output.

The following chart depicts our energy resource mix, which is the electricity we use to serve our customers, in 2005 and 2022 and the projected mix in 2030 and 2050. The amounts include energy generated from owned resources, procured through power purchase agreements and energy purchased in the wholesale market:



(1) Includes owned generation from renewable sources and wind energy purchased through power purchase agreements.

Inflation Reduction Act

On August 16, 2022, the Inflation Reduction Act of 2022 (IRA) was signed into law. The IRA includes funding for climate and clean energy investments and other provisions affecting corporate taxpayers. The climate and clean energy provisions of the IRA include, among other items, i) the extension of the traditional production tax credits (PTC) and investment tax credits (ITC) for renewable technologies (including wind and solar) if construction is begun before 2025, along with elimination of the existing phase-down of the PTC and ITC, and transitions to a new technology neutral credit for property placed in service after 2024, ii) a new PTC for sale of domestically produced electricity with a GHG emission rate of not greater than zero produced at a qualifying facility placed in service after 2024, iii) a new ITC for investment in qualifying zero-emission electricity generation facilities or energy storage technology placed in service after 2024, and iv) alternative ways to monetize renewable tax credits by allowing certain entities to sell tax credits to third parties.

The tax incentives provided under the IRA are intended to incentivize the transition to a cleaner energy economy and to reduce GHG emissions from the electric utility industry. These financial incentives could impact the planning of our future generation resources and our long-term capital spending plan. See the Integrated Resource Plan (IRP) section below for additional details on how the passage of the IRA has impacted our recently filed IRP.

RESOURCE MATERIALS

Coal is the principal fuel burned at our jointly-owned Big Stone and Coyote Station generating plants. Coyote Station, a mine-mouth facility, burns North Dakota lignite coal. Big Stone Plant burns western subbituminous coal transported by rail. We source coal for our coal-fired power plants through requirements contracts which do not include minimum purchase requirements but do require all coal necessary for the operation of the respective plant to be purchased from the counterparty. Our coal supply contracts for our Big Stone Plant and Coyote Station have expiration dates in 2024 and 2040.

The supply agreement between the Coyote Station owners, including OTP, and the coal supplier includes provisions requiring the Coyote Station owners to purchase the membership interests and pay off or assume loan and lease obligations of the coal supplier, as well as complete mine closing and post-mining reclamation, in the event of certain early termination events and at the expiration of the coal supply agreement in 2040. See below and Note 1 to our consolidated financial statements included in this report on Form 10-K for additional information.

Coal is transported to our non-mine-mouth facility, Big Stone Plant, by rail and is provided under a common carrier rate which includes a mileage-based fuel surcharge.

We purchase natural gas for use at our combustion turbine facilities based on anticipated short-term resource needs. We procure natural gas from multiple vendors at spot prices in a liquid market primarily under firm delivery contracts.

TRANSMISSION AND DISTRIBUTION

Our transmission and distribution assets deliver energy from energy generation sources to our customers. In addition, we earn revenue from the transmission of electricity over our wholly- or jointly-owned transmission assets for others under approved rate tariffs. As of December 31, 2022, we were the sole or joint owner of nearly 15,000 miles of transmission and distribution lines.

Midcontinent Independent System Operator

MISO is an independent, non-profit organization that operates the transmission facilities owned by other entities, including OTP, within its regional jurisdiction and administers energy and generation capacity markets. MISO has operational control of our transmission facilities above 100 kilovolts (kV). MISO seeks to optimize the efficiency of the interconnected system, provide solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions.

In 2022, MISO approved several projects within the first tranche of its long-range transmission plan, which includes two new 345 kV transmission projects and a project to upgrade an existing transmission line. OTP will have a varying level of ownership interest in these projects, which will be completed over several years, and our total capital investment in these projects is anticipated to be approximately $390 million.

SEASONALITY

Electricity demand is affected by seasonal weather differences, with peak demand occurring in the summer and winter months. As a result, our Electric segment operating results regularly fluctuate on a seasonal basis. In addition, fluctuations in electricity demand within the same season but between years can impact our operating results. We monitor the level of heating and cooling degree days in a period to assess the impact of weather-related effects on our operating results between periods.

PUBLIC UTILITY REGULATION

OTP is subject to regulation of rates and other matters in each of the three states in which it operates and by the federal government for, among other matters, the interstate transmission of electricity. OTP operates under approved retail electric tariff rates in all three states it serves. Tariff rates are designed to recover plant investments, a return on those investments, and operating costs. In addition to determining rate tariffs, state regulatory commissions also authorize return on equity (ROE), capital structure, and depreciation rates of our plant investments. Decisions by our regulators significantly impact our operating results, financial position, and cash flows.

Below is a summary of the regulatory agencies with jurisdiction of electric rates over OTP covered by each regulatory agency:

Regulatory Agency	***Areas of Regulation***
Minnesota Public Utilities Commission (MPUC)	Retail rates, issuance of securities, depreciation rates, capital structure, public utility services, construction of major facilities, establishment of exclusive assigned service areas, contracts with subsidiaries and other affiliated interests and other matters. Selection or designation of sites for new generating plants (50,000 kW or more) and routes for transmission lines (100 kV or more). Review and approval of fifteen-year Integrated Resource Plan.
North Dakota Public Service Commission (NDPSC)	Retail rates, certain issuances of securities, construction of major utility facilities and other matters. Approval of site and routes for new electric generating facilities (>500 kW for wind generating facilities; >50,000 kW for non-wind generating facilities) and high voltage transmission lines (>115 kV). Review and approval of fifteen-year Integrated Resource Plan.
South Dakota Public Utilities Commission (SDPUC)	Retail rates, public utility services, construction of major facilities, establishment of assigned service areas and other matters. Approval of sites and routes for new electric generating facilities (100,000 kW or more) and most transmission lines (115 kV or more).
Federal Energy Regulatory Commission (FERC)	Wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, hydroelectric licensing and accounting policies and practices. Compliance with North American Electric Reliability Corporation (NERC) reliability standards, including standards on cybersecurity and protection of critical infrastructure.

In addition to base rates, which are established through periodic rate case proceedings within each state jurisdiction, there are other mechanisms for recovery of plant investments, including a return on investment and operating expenses, between rate cases. The following table summarizes these recovery mechanisms:

Recovery Mechanism	***Jurisdiction(s)***	***Additional Information***
Fuel Clause Adjustment (FCA)	MN, ND, SD	Provides for periodic billing adjustments for changes in prudently incurred costs of fuel and purchased power. In North and South Dakota, fuel and purchased power costs are generally adjusted on a monthly basis with over or under collections from the previous month applied to the next monthly billing. In Minnesota, fuel and purchased power costs are estimated on an annual basis and the accumulated difference between actual and estimated cost per kwh are refunded or recovered, subject to regulatory approval, in subsequent periods.
Transmission Cost Recovery Rider (TCR)	MN, ND, SD	Provides for the recovery of costs outside of a general rate case for investments in new or modified electric transmission assets and certain MISO transmission service and related costs.
Environmental Cost Recovery Rider (ECR)	MN, ND, SD	Provides for the recovery of costs outside of a general rate case for investments in certain environmental improvement projects.
Renewable Resource Rider (RRR)	MN, ND	Provides for the recovery of costs outside of a general rate case for investments in certain new renewable energy projects.
Conservation Improvement Program (CIP)	MN	Under Minnesota law, OTP is required to save 1.75% of its gross retail energy revenues through the energy conservation and optimization program. Recovery of these costs outside of a general rate case occurs through the CIP rider.
Electric Utility Infrastructure Costs Rider (EUIC)	MN	Provides for the recovery of costs for investments made to replace or modify existing infrastructure if the replacement or modification conserves energy or uses energy more efficiently.
Advanced Meter and Distribution Technology Cost Recovery Rider (AMDT)	ND	Provides for the recovery of costs for advanced metering infrastructure, outage management systems and demand response projects.
Generation Cost Recovery Rider (GCR)	ND	Provides for the recovery of costs outside of a general rate case for investments in new generation facilities.
Energy Efficiency Plan (EEP)	SD	Provides for the recovery of costs from energy efficiency investments.
Phase-In Rider (PIR)	SD	Provides for the recovery of costs outside of a general rate case for investments in new generation facilities and advanced grid infrastructure.

Integrated Resource Plan

Under Minnesota law, utilities are required to submit for approval by the MPUC a 15-year advance IRP. An IRP is a set of resource options a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the utility’s supply and demand circumstances, and the extent to which each resource option would be used to meet those service needs. The MPUC’s findings of fact and conclusions regarding IRPs are considered to be prima facie evidence, subject to rebuttal, in future rate reviews and other proceedings. Typically, IRPs are submitted every two years.

In 2021, the North Dakota Legislative Assembly enacted a provision requiring investor-owned electric utilities to submit an IRP to the NDPSC and granted the NDPSC the authority to adopt rules and regulations for the preparation and submission of IRPs. The NDPSC's rules and regulations were finalized and became effective on January 1, 2023. Under the finalized regulation, utilities are required to submit, for approval by the NDPSC, a 15-year advance IRP every three years.

On September 1, 2021, OTP filed its 2022 IRP concurrently with regulators in Minnesota, North Dakota and South Dakota. The 2022 IRP included OTP’s preferred plan for meeting customers’ anticipated capacity and energy needs while maintaining system reliability and affordable electric service rates, based on the information available at that time. The preferred plan as outlined in the 2022 IRP included the addition of dual fuel capabilities at our Astoria natural gas plant, the addition of 150-megawatts of solar generation, the addition of 100-megawatts of wind generation, and the commencement of the process of withdrawing from our 35 percent ownership interest in Coyote Station, a jointly-owned, coal-fired generation plant, by December 31, 2028.

Subject to regulatory approval, the preferred plan proposed to create a regulatory asset as a vehicle to recover costs related to a future withdrawal from Coyote Station, including the net book value of the plant on the withdrawal date, anticipated decommissioning costs and any required costs incurred as a result of an early termination of the existing lignite sales agreement (LSA), under which Coyote Station acquires all of its lignite coal from a nearby mine. As part of the filing, OTP developed an estimate of the reasonably foreseeable costs of withdrawing from Coyote Station at the end of 2028 of $68.5 million. These costs may differ from actual results due to the uncertainty and timing of future events associated with the terms and conditions of a withdrawal.

On October 14, 2022, OTP submitted a supplemental filing to update its 2022 IRP, requesting the procedural schedule in Minnesota be amended to allow additional time to update our resource modeling given significant changes in the energy industry since the original 2022 IRP filing, while maintaining the original procedural schedule as it relates to adding dual fuel capability at Astoria. Our original filing proposed fuel oil as the secondary on-site fuel at Astoria and our supplemental filing reflects revised cost estimates and proposes liquified natural gas as the most cost-effective secondary fuel source. The primary changes and events which led to OTP's request include FERC’s approval of MISO’s new seasonal resource adequacy construct, MISO's proposal to significantly increase winter and spring planning reserve margins, and enactment of the IRA. A notice of the request submitted to the MPUC was also provided to the NDPSC and SDPUC.

On November 1, 2022, the MPUC approved OTP's requested changes to the procedural schedule for the 2022 IRP. OTP plans to file an updated resource plan in March 2023, pursuant to the amended schedule. In conjunction with the updated resource plan, OTP's preferred plan could change based on the results of updated resource modeling incorporating the factors listed above, as well as other changes. A change to the preferred plan could ultimately impact the nature, timing and amount of future capital investments, as well as the potential for OTP's withdrawal from Coyote Station.

Capital Structure Petition
Minnesota law requires an annual filing of a capital structure petition with the MPUC. In this filing the MPUC reviews and approves OTP's capital structure. Once approved, OTP may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved petition. OTP's current capital structure approved by the MPUC on November 8, 2022, allows for an equity-to-total-capitalization ratio between 47.5% and 58.0%, with total capitalization not to exceed $1.8 billion.

Renewable Energy Standard
Minnesota has a renewable energy standard requiring utilities to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 25% by 2025 and 55% by 2035. Qualifying renewable sources are classified as wind, hydropower, hydrogen, and certain biomass generation. We met the current renewable sources requirements with a combination of owned renewable generation and purchases from renewable generation sources. Minnesota law also requires 1.5% of total Minnesota retail electric sales by public utilities to be supplied by solar energy. For a public utility with between 50,000 and 200,000 retail electric customers, such as OTP, at least 10% of the 1.5% requirement must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less. OTP plans to purchase Solar Renewable Energy Credits to meet its obligations until its Hoot Lake Solar and other solar projects are complete and operational. Under certain circumstances, and after consideration of customers' utility costs and reliability issues, the MPUC may modify or delay implementation of the standards. We are evaluating potential options for maintaining compliance and meeting the solar energy standard beyond 2022.

Minnesota Clean Energy Bill
In February 2022, Minnesota enacted the Clean Energy Bill, which requires electric utilities to generate or procure sufficient electricity from carbon-free resources, to provide retail customers in Minnesota with at least the following percentages of carbon-free electric energy: 80% by 2030, 90% by 2035, and 100% by 2040. Carbon-free resources include wind, solar, hydropower, and nuclear generation. To provide flexibility, the law allows electric utilities to use renewable energy credits (RECs) to offset carbon emissions and for the MPUC to consider whether a regulated utility's requirement to meet established standards should be delayed due to affordability or reliability impacts. OTP is in the process of reviewing its plan for compliance with the newly enacted law.

ENVIRONMENTAL REGULATION
OTP is subject to stringent federal and state environmental standards and regulations regarding, among other things, air, water and solid waste pollution. OTP's facilities have been designed, constructed and, as necessary, updated to operate in compliance with applicable environmental regulations. However, new or amended laws and regulations or changes in interpretations of current laws and regulations may require additional pollution control equipment or emission reduction measures and there can be no assurance that our facilities will remain economic to operate. Prudent expenditures incurred to comply with environmental regulations are eligible to be recovered in rates authorized by regulators in jurisdictions in which we operate; however, there can be no assurance that future costs will be authorized for recovery. Alternatively, additional pollution control equipment or other emission reduction measures may prove to be uneconomic potentially leading to the exiting of a facility earlier than originally planned. As it relates to our jointly-owned facilities, we may determine it is necessary to transfer, sell or otherwise divest of our ownership, or the ownership group may determine the early closure or repurposing of a facility is necessary.

For the five-year period ended December 31, 2022, OTP invested approximately $10.4 million in environmental control facilities, including $0.4 million in 2022. Our construction budget for the next five years includes approximately $6.1 million of capital investments in environmental control equipment. The timing and amount of our expenditures may change as the regulatory environment changes.

Among current regulatory requirements, the federal Regional Haze Rule (RHR) could have the most significant impact on our operating results, financial condition and liquidity.

The Environmental Protection Agency (EPA) adopted the RHR in 1999 as an effort to improve visibility in national parks and wilderness areas. The RHR requires states, in coordination with the EPA and other governmental agencies, to develop and implement state implementation plans (SIPs) which work towards achieving natural visibility conditions by the year 2064, to set goals to ensure reasonable progress is being made, and to periodically evaluate whether those goals and progress are on track or whether additional emission reductions are appropriate. The second RHR implementation period covers the years 2018-2028. States are required to submit a state implementation plan to assess reasonable progress with the RHR and determine what additional emission reductions are appropriate, if any.

Coyote Station is subject to assessment in the second implementation period under the North Dakota SIP for the RHR. The North Dakota Department of Environmental Quality (NDDEQ) submitted its proposed SIP to the EPA for approval in August 2022. In its plan, the NDDEQ concluded it is not reasonable to require additional emission controls during this planning period. The EPA submitted comments during the development of the SIP requesting NDDEQ to reassess its determination for Coyote Station. The EPA is anticipated to take proposed action and potential final action on the SIP in 2023. See Note 13 to our consolidated financial statements for additional information.

Climate Change and Greenhouse Gas Regulation
Global climate change presents a significant energy and environmental policy challenge. Combustion of fossil fuels for the generation of electricity is a considerable source of CO_2 emissions, which is the primary GHG emitted by our utility operations. The federal government and many states are pursuing climate policies to regulate GHG emissions as part of a broad-based effort to limit global warming.

In February 2021, the U.S. rejoined the United Nations Framework Convention on Climate Change (the Paris Agreement), which is a legally binding international treaty on climate change adopted by over 190 countries. The goal of the Paris Agreement is to limit the global temperature increase to well below 2° Celsius compared to pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5° Celsius. The Biden Administration has announced the goal of reducing GHG emissions by 50 to 52 percent from 2005 levels in 2030 and to reach 100 percent carbon pollution-free electricity by 2035 as part of the U.S. plan to achieve the goals under the Paris Agreement.

In February 2022, Minnesota enacted the Clean Energy Bill, which requires electric utilities to generate or procure sufficient electricity from carbon-free resources to provide retail customers in Minnesota with at least the following percentages of carbon-free electric energy: 80% by 2030, 90% by 2035, and 100% by 2040.

The implementation of climate change programs, such as the Paris Agreement, the Minnesota Clean Energy Bill, and other federal or state regulations targeting GHG emissions may have a significant impact on our utility business. Specific regulatory measures to address climate change continue to evolve. In January 2021, the EPA's Affordable Clean Energy Rule (ACE Rule), which required states to develop plans for GHG emissions from coal-fired power plants, was vacated by the U.S. Court of Appeals for the District of Columbia Circuit. In October 2021, the U.S. Supreme Court agreed to hear a consolidated challenge to the Court of Appeals decisions. In June 2022, the U.S. Supreme Court issued its opinion in the case of West Virginia v. EPA, finding that in Section 111(d) of the Clean Air Act, Congress did not grant the EPA the authority to broadly regulate GHG emissions under the Clean Air Act, including the setting of emissions limits for existing power plants based on the power sector's ability to shift to cleaner renewable energy sources (a process known as "generation shifting"). The Supreme Court found that the authority to regulate issues that have broad economic or political consequences (known as the "major questions doctrine") requires explicit Congressional authorization in law. In the first half of 2023, the EPA is expected to issue a proposed rule under Clean Air Act section 111(d), replacing or revising the previously proposed ACE rule. Although this future proposed rule is subject to the constraints of the Supreme Court's West Virginia v. EPA decision, the rule nevertheless has the potential to impact the emissions controls needed at OTP's coal-fired power plants.

While the future financial impact of any current, proposed, or pending litigation or regulation of GHG or other emissions is unknown at this time, any capital or operating costs incurred for additional pollution control equipment or emission reduction measures could materially adversely impact our future operating results, financial position, and liquidity unless such costs could be recovered through related rates and/or future market prices for energy.

MANUFACTURING

Contribution to Operating Revenues: 27% (2022), 28% (2021), 27% (2020)

Manufacturing consists of businesses engaged in the following activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components and extruded raw material stock. The following is a brief description of each of these businesses:

BTD Manufacturing, Inc. (BTD), with headquarters located in Detroit Lakes, Minnesota, provides metal fabrication services for custom machine parts and metal components through metal stamping, tool and die, machining, tube bending, welding and assembly in its facilities in Detroit Lakes and Lakeville, Minnesota, Washington, Illinois and Dawsonville, Georgia.

T.O. Plastics, Inc. (T.O. Plastics), with facilities in Otsego and Clearwater, Minnesota, manufactures extruded and thermoformed plastic products, including custom parts for customers in several industries and its own line of horticulture containers. Examples of products produced include clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts.

CUSTOMERS
Our metal fabrication business primarily serves Midwestern and Southeastern U.S. manufacturers in the recreational vehicle, lawn and garden, agricultural, construction, and industrial and energy equipment end markets. Our plastic products business serves primarily U.S. customers in the horticulture, medical and life sciences, industrial, recreational and electronics industries. The principal method of production distribution is by direct shipment to our customers through direct customer pick-up or common carrier ground transportation.

No single customer or product of our Manufacturing segment businesses accounted for 10% or more of our consolidated operating revenues in 2022. However, the top three customers combined to account for 50% and 46% of our 2022 and 2021 Manufacturing segment operating revenues, respectively.

COMPETITIVE CONDITIONS
The various markets in which we compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources, excess capacity, labor advantages and larger marketing, research and development staffs and facilities than our own.

We believe the principal competitive factors in our Manufacturing segment are product performance, quality, price, technical innovation, cost effectiveness, customer service and breadth of product line. We intend to continue to compete based on high-performance products, innovative production technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

RESOURCE MATERIALS

We use raw materials in the products we manufacture, including, among others, steel, aluminum, and polystyrene and other plastics resins. Managing price volatility and ensuring raw material availability are important aspects of our business. We attempt to pass increases in the costs of these raw materials through to our customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins. Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of our Manufacturing segment as it reduces their ability to mitigate the costs associated with excess material.

ENVIRONMENTAL REGULATION

Our manufacturing businesses are subject to environmental, health and safety laws and regulations, including those governing discharges to air and water, the management and disposal of hazardous substances, the cleanup of contaminated sites and health and safety matters.

PLASTICS

Contribution to Operating Revenues: 35% (2022), 32% (2021), 23% (2020)

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The following is a brief description of these businesses:

Northern Pipe Products, Inc. (Northern Pipe), located in Fargo, North Dakota, manufactures and sells PVC pipe for municipal water, rural water, wastewater, storm drainage systems and other uses in the northern, midwestern, south-central and western regions of the United States as well as central and western Canada.

Vinyltech Corporation (Vinyltech), located in Phoenix, Arizona, manufactures and sells PVC pipe for municipal water, wastewater, water reclamation systems and other uses in the western, northwest and south-central regions of the United States.

PVC pipe is manufactured through a process known as extrusion. During this process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is pulled through a series of water-cooling tanks, marked to identify the type of pipe and cut to finished lengths.

CUSTOMERS

PVC pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for our PVC pipe products consist primarily of wholesalers and distributors and the principal method for distribution of our products is by common carrier ground transportation. No single customer of the PVC pipe companies accounted for 10% or more of our consolidated operating revenues in 2022. However, two customers, both of which are distributors of PVC pipe, combined to account for 46% and 50% of our 2022 and 2021 Plastics segment operating revenues, respectively.

COMPETITIVE CONDITIONS

The plastic pipe industry is fragmented and competitive due to the number of producers, the small number of raw material suppliers and the fungible nature of the product. Due to shipping costs, competition is usually regional instead of national in scope. The principal factors of competition are price, customer service and product performance. We compete not only against other plastic pipe manufacturers, but also ductile iron, high-density polyethylene, steel and concrete pipe producers. Pricing pressure will continue to affect our operating margins in the future.

We will continue to compete based on our high-quality products, cost-effective production techniques and close customer relations and support.

RESOURCE MATERIALS

PVC resins are acquired in bulk and shipped to our facilities by rail. There are four vendors from which we can source our PVC resin requirements. In 2022 we sourced all of our PVC resin from two vendors. Our contractual arrangements to acquire resin generally include estimated annual order quantities with no required minimum purchases, and include variable pricing based on market prices for resin. The supply of PVC resin may also be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region. These plants are subject to the risk of damage and production shutdowns because of exposure to hurricanes or other extreme weather events that occur in this part of the United States. The loss of a key vendor, or any interruption or delay in the supply of PVC resin could disrupt the ability of our Plastics segment businesses to manufacture products, cause customers to cancel orders or result in increased expenses for obtaining PVC resin from alternative sources, if such sources were available. We believe we have good relationships with our key raw material vendors.

Due to the commodity nature of PVC resin and PVC pipe and the dynamic supply and demand factors worldwide, historically the markets for both PVC resin and PVC pipe have been very cyclical with significant fluctuations in prices and gross margins.

In addition to PVC resin, we use certain other materials, such as stabilizers, gaskets and lumber, in the process of manufacturing and shipping our PVC pipe products. We generally source these materials from a limited number of suppliers, and supply chain constraints or disruptions related to these materials could disrupt our ability to manufacture or ship products and could result in increased costs.

SEASONALITY

Demand for our PVC pipe products can be impacted by seasonal weather differences, with generally lower sales volumes realized in the first quarter of the year when cold temperatures and frozen ground across the northern portion of our footprint can delay or prevent construction activity and consequently delay or prevent customer orders of PVC pipe.

ENVIRONMENTAL REGULATION

Our plastics businesses are subject to environmental, health and safety laws and regulations, including those governing discharges to air and water, the management and disposal of hazardous substances, the cleanup of contaminated sites and health and safety matters.

ITEM 1A. RISK FACTORS

RISK FACTORS AND CAUTIONARY STATEMENTS
Our businesses are subject to various risks and uncertainties. Any of the risks described below or elsewhere in this report on Form 10-K or in our other SEC filings could materially adversely affect our business, operating results, financial condition and liquidity. Additional risks and uncertainties we are not presently aware of or that we currently consider immaterial may also affect our business, operating results, financial condition and liquidity.

Oversight of Risk and Related Processes
A key accountability of the Board of Directors is the oversight of material risk. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of significant and emerging risks. Management identifies and analyzes risks to determine the impact and other attributes such as timing, likelihood and management control. Identification and analysis occur formally through an assessment of significant and emerging risks conducted by senior management, the financial disclosure process, and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through the development of goals and key performance indicators, which include risk identification to determine barriers to implementing our strategy. We promote a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of business ethics and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. We manage and further mitigate risks through formal risk management structures, including a management executive risk committee and internal business functions such as internal audit/business risk management and legal. Management communicates regularly with our Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to our Board of Directors which provides information on the risks management believes are material, including the earnings impact, timing, likelihood and management control. The Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of Otter Tail Corporation. The Board of Directors regularly reviews management's top risk assessment and analyzes areas of existing and future risks and opportunities. Finally, the Board of Directors conducts an annual strategy session where our future plans and initiatives are reviewed.

OPERATIONAL RISKS

Our strategy includes large capital investments, which are subject to risks.
Our business strategy includes major capital investments at our existing companies. Our capital investment program planned for the next five years includes Electric segment investments in renewable generation, transmission asset additions and upgrades, and technology and infrastructure projects, and Manufacturing and Plastics segments investments in facilities, equipment and machinery. These capital projects are planned years in advance of their in-service dates and are subject to various risks including: obtaining necessary permits, licenses and timely approvals; adverse changes in regulatory treatment or public policy; changes in commodity pricing, equipment and construction costs; technology changes; delivery delays of critical materials and components; delays caused by construction accidents, injuries or public health crises; adverse weather conditions; unforeseen product defects; limited access to capital; and other adverse conditions. Capital investments in our Electric segment require regulatory approval and are subject to the risks of not being granted timely or allowed to be fully recovered. The inability to complete capital projects on budget and in a timely manner could adversely impact our operating results and financial condition.

Our acquisition or divestiture strategies are subject to risk and could adversely impact our financial position and operating results.
As part of our business strategy, we continually assess our mix of businesses and potential strategic acquisitions or divestitures. This investment strategy is subject to various risks including the ability to identify appropriate acquisition candidates or successfully negotiate and finance any acquisitions. In addition, difficulties in integrating the operations, services, products and personnel of the acquired business, and the potential loss of key employees, customers and suppliers of the acquired business could adversely impact our financial condition and operating results.

The sale of any of our businesses may result in the recognition of a loss if the business is sold for less than its book value and may expose us to risk arising from indemnification obligations that arose out of the conduct of the business prior to the sale. These obligations may include warranty and environmental obligations or the recoverability of certain assets sold as part of the transaction. Unforeseen costs related to these obligations could impact our operating results.

Weather impacts, including normal seasonal fluctuation and extreme weather events, could adversely affect our operating results.
Our Electric segment business is seasonal and weather patterns can have a material impact on our financial performance. Demand for electricity is normally greater in the winter and summer months. Unusually mild summers and winters could have an adverse effect on our financial condition and results of operations. Weather can also have a significant impact on our Plastics segment businesses as most U.S. PVC resin production plants are located in the Gulf Coast region, which is prone to seasonal hurricane activity and other extreme weather events. Our access to PVC resin may be impacted by the volume and magnitude of hurricane and storm activity in this region. In addition, our Plastics segment businesses can be affected by weather prohibiting or delaying construction projects at any time of the year in any geography, but specifically times of the year when frozen ground and cold temperatures in many parts of the country can delay construction projects, all of which can result in reduced customer demand.

Our businesses are located in areas that could be subject to natural disasters such as severe snow and ice storms, tornadoes, flooding and fires. These factors could result in interruption of our business and damage to our facilities. An extreme weather event within our utility service area could directly affect our capital assets, causing disruption in service to customers and result in repair or replacement costs, due to downed wires and poles or damage to other operating equipment.

In addition to variations in seasonal weather patterns, more widespread climate change may also create physical and financial risk to our businesses. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability and other phenomena, could affect some or all of our operations. Severe weather or other natural disasters related to climate change could be destructive and result in increased costs and disruptions in our operations. Extreme weather conditions, such as uncommonly long periods of high or low ambient temperature, generally require more utility system backup, adding to costs and contributing to increased system stress on our utility infrastructure, which could cause service interruptions.

The loss of, or significant reduction in revenue from, any of our key customers could have an adverse effect on our operating results.
While no single customer provided more than 10% of our consolidated operating revenues, each of our segments have customers which accounted for over 10% of the segment's operating revenues. In 2022, one customer accounted for 11% of Electric segment revenues, three customers combined to account for 50% of Manufacturing segment operating revenues and two customers combined to account for 46% of Plastics segment operating revenues. The loss of any one of these customers or a significant decline in sales to these customers, would have a significant negative impact on the segment's financial condition and operating results, and could have a significant negative impact on the Company's consolidated financial condition, operating results and liquidity.

Electric segment operating revenues also include sales to a customer that is a developer and operator of data centers which serve the high performance computing industry, with a concentration of customers involved in cryptocurrency mining and related activities. Customer demand from their cryptocurrency mining customers can directly impact our customer's demand for electricity. The cryptocurrency industry is highly volatile, and a significant decrease in cryptocurrency mining demand could have a negative impact on our customer's demand for electricity, and therefore negatively impact our operating revenues.

We are subject to counterparty credit risk.
We extend credit to our customers in the ordinary course of business in each of our operating segments. Our customers' ability to pay depends on a variety of factors including macroeconomic conditions, local economic conditions including unemployment rates, and industry conditions in which our customers operate. Increased customer delinquencies and bad debts could adversely impact our operating results and liquidity.

Our operations are subject to environmental, health and safety laws and regulations.
We are subject to numerous federal, state, and local environmental, health and safety laws and regulations governing, among other things, discharges to air and water, natural resources, hazardous waste and toxic substances, the cleanup of contaminated sites, and health and safety matters. Our failure to comply with applicable laws and regulations could result in civil or criminal fines or penalties, enforcement actions, and regulatory or judicial orders enjoining or curtailing operations or requiring corrective measures, which could materially and adversely affect our business. Compliance with these laws and regulations is a significant factor in our business. We have incurred and expect to continue to incur capital expenditures and operating costs to comply with applicable current and future laws and regulations.

Our businesses continue to be subject to additional and changing environmental, health and safety laws and regulations, and we could incur additional costs complying with requirements that are promulgated in the future. Recently, various federal and state agencies have heightened their scrutiny of per- and polyfluoroalkyl substances (PFAS), which are manufactured chemicals used in a variety of consumer and industrial products. In August 2022, the U.S. EPA proposed to designate perfluorooctanesulfonic acid (PFOS) and perfluorooctanoic acid (PFOA), two of the most common PFAS chemicals, as hazardous substances, which could have wide-ranging impacts on companies across various industries, including ours. We are investigating whether PFAS compounds are used in our manufacturing or operating processes that occur in our various businesses. At this time, we cannot predict the outcome or the severity of the impact, if any, of future laws or regulations enacted to address PFAS.

A cyber incident, security breach or system failure could adversely affect our business and operating results.
The operation of our business is dependent on the secure functioning of our computer hardware and software systems. Furthermore, all our businesses require us to collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss. We also use third-party vendors to electronically process certain of our business transactions. Information systems, both ours and those of third parties, are vulnerable to security breaches by computer hackers and cyber terrorists and the negligent or intentional breach of established controls and procedures or mismanagement of confidential information by employees. We may also be impacted by attacks and data security breaches of financial institutions, merchants or third-party service providers. While we employ a defense-in-depth strategy and regularly conduct cybersecurity assessments, we cannot be certain our information security systems and protocols and those of our vendors and other third parties are sufficient to withstand a cyber-attack or other security breach.

A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For example, we may be subject to liability under various federal, state and international data protection laws. These laws are subject to change and expansion and may require additional operational changes and costs to comply.

The misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant monetary damages, regulatory enforcement actions and breach notification and mitigation expenses, such as credit monitoring, and result in reputational damage affecting relations with shareholders, customers, regulators and others. In addition to property and casualty insurance, which may cover restoration of data, certain physical damage or third-party injuries, we have cybersecurity insurance related to a breach event. However, damage and claims arising from such incidents may not be covered or may exceed the amount of any available insurance.

The inability to attract and retain a qualified workforce could have an adverse effect on our operations.
The success of our business is heavily dependent on the leadership of our executive officers and key employees for implementation of our strategy. In addition, all of our businesses rely on a qualified workforce, including technical employees who possess certain specialized knowledge and skills. The inability to attract and retain a skilled and stable workforce at necessary staffing levels, whether due to decreases in hiring rates, increases in employee retirements, increases in terminations, or any combination thereof, may negatively affect our ability to service our customers, manufacture products or successfully manage our business and achieve our objectives.

In 2022, we faced labor challenges within our Manufacturing segment businesses including difficulty attracting and retaining employees. In response, we offered increased compensation and hiring and retention incentives, which led to increased costs in our business. Should these challenges persist or exacerbate, our financial results could be impacted. If we are unable to maintain our desired staffing levels our ability to meet customer demand and achieve our growth targets could be negatively impacted.

FINANCIAL RISKS

We are subject to capital market and interest rate risks.
We rely on access to debt and equity capital markets as a source of liquidity to fund our investment initiatives, including rate base growth investments in our Electric segment and opportunities for investment, including acquisitions, in our Manufacturing and Plastics segments. Capital markets are impacted by global and domestic economic conditions, monetary policy, commodity prices, geopolitical events and other factors. If we are unable to access capital on acceptable terms and at reasonable costs, our ability to implement our business plans may be adversely affected. In addition, higher market interest rates on outstanding variable-rate, short-term indebtedness could also impact our operating results. In 2022, rising market interest rates caused the applicable rate of interest on our short-term indebtedness to increase significantly. However, the impact to our operating results was not significant due to our low level of outstanding borrowings on our short-term indebtedness. Our operating results could be impacted if we significantly increase our short-term borrowings or issue new long-term debt, and interest rates remain elevated or continue to increase.

A decrease in our credit ratings could increase our borrowing costs and result in additional contractual costs.
We rely on our investment grade credit ratings to provide acceptable costs for accessing the capital markets. A downgrade of our credit ratings could result in higher borrowing costs thereby negatively impacting our operating results and limiting our ability to access capital markets, which may negatively impact our ability to implement our business plans. In addition, OTP is a party to contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below certain levels.

Our pension and other postretirement benefit plans are subject to investment and interest rate risks.
The financial obligations and related costs of our pension and other postretirement benefit plans are affected by numerous factors. Assumptions related to future costs, investment returns, actuarial estimates and interest rates have a significant effect on our funding obligations and the cost recognized related to these plans. If our pension plan assets do not achieve our estimated long-term rate of return or if our other estimates prove to be inaccurate, our operating results, financial condition and liquidity may be adversely impacted. In addition, our funding requirements could be impacted by changes to the Pension Protection Act.

We rely on our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and pay dividends to our shareholders.
Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the earnings, cash flows, capital requirements and general financial positions of our subsidiary companies. In addition, OTP is subject to federal and state regulations which may restrict its ability to pay dividends. Finally, we are also reliant on our subsidiary companies to maintain compliance with financial covenants under our various short- and long-term debt agreements. Our debt agreements include restrictions on the payment of cash dividends upon an event of default.

Changes in tax laws could materially affect our financial condition and operating results.
Our provision for income taxes and tax obligations are impacted by various tax laws and regulations, including the availability of various tax credits, IRS tax policies such as tax normalization and, at times, the ability to carryforward net operating losses and tax credits. Changes in tax laws, regulations and interpretations could have an adverse effect on our financial condition and operating results. Tax law changes that reduce or eliminate production or investment tax credits may impact the economics of constructing certain electric generation resources, which may impact our planned investments and could adversely affect our financial condition and operating results.

A significant impairment of our goodwill would negatively impact our financial position and operating results.
As of December 31, 2022, we had $37.6 million of goodwill recorded on our consolidated balance sheet related to businesses within our Manufacturing and Plastics segments. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. The goodwill impairment test requires us to estimate the fair value of the businesses being tested. Estimating the fair value of a business unit requires significant judgments and estimates, including estimates of future operating results and cash flows, among others. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions or material differences between actual and forecasted financial performance could affect our fair value estimates and lead to a goodwill impairment charge that could adversely affect our financial condition and operating results, as well as impact compliance with financing agreement covenants.

ELECTRIC SEGMENT RISKS

General economic and industry conditions impact our business.
Several factors, many of which are beyond our control, may contribute to reduced demand for energy from our customers or increase the cost of providing energy to our customers. These risks include economic growth or decline in our service areas, demographic changes in our customer base and changes in customer demand or load growth due to, among other items, proliferation of distributed generation, energy efficiency initiatives and technological advancements. In addition, customer demand could be impacted by increased competition in our service territories or the loss of a service territory or franchise. Other risks include increased transmission or interconnection costs, generation curtailment and changes in the

manner in which wholesale power is purchased and sold. A decrease in revenues or an increase in expenses related to our electric operations could negatively impact our financial condition, operating results and liquidity.

Our utility business is significantly impacted by government legislation and regulation.
OTP is subject to federal and state legislation and comprehensive regulation by federal and state regulatory agencies, including the public utility commissions in each of the three states in which OTP operates, and by the FERC. State utility commissions regulate, among other matters, the establishment of assigned service areas, the siting and construction of major facilities, the capital structure of the utility business, and the allowed rates to charge customers for providing energy and utility service. Each state utility commission operates independent of one another; therefore, OTP is subject to and must adhere to the decisions of each independent state commission. The FERC regulates, among other matters, wholesale energy transactions, hydroelectric licensing, transmission and sale of electric energy in interstate commerce, and the interconnection of electric facilities.

Our financial condition, operating results and liquidity are significantly impacted by, and dependent upon, our ability to recover the costs associated with providing utility service and earn a return on our utility capital investments. There is no assurance that each state utility commission will judge our utility costs to have been prudently incurred or that rates will produce full recovery of such costs. In addition, changes in the federal or state regulatory framework could impair our ability to recover utility costs historically collected from our customers. In addition, prolonged inflationary cost pressures would increase the cost of constructing our utility assets and operating our utility business. Rising fuel costs in 2022 have increased the cost of providing energy to our customers. In each instance, there can be no assurance that our state regulatory commissions will authorize recovery of these rising costs.

In addition to the recovery of our utility costs, our profitability is impacted by our authorized ROE, which can be impacted by macroeconomic factors such as interest rates. There can be no assurance that each state utility commission or the FERC will authorize a rate of return which allows us to achieve our financial goals.

An adverse decision by one or more regulatory authorities concerning the level or method of determining electric utility rates; the authorized returns on equity; the authority to self-fund transmission upgrades; recoverability of fuel, purchase power and other costs; the allocation of costs between jurisdictions, approval of depreciation rates; implementation of enforceable federal reliability standards or other regulatory matters; permitted business activities, such as ownership or operation of nonelectric businesses; or any prolonged delay in rendering a decision in a rate or other proceeding could adversely impact our financial condition, operating results and liquidity.

Our generating facilities are subject to risks that could result in early closure or the sale of our ownership interest.
Changes in operational or economic factors, environmental regulation or risks of litigation could result in the early closure of or the sale of our interest in a generating facility. In the event of an early closure, a significant asset impairment charge could be required and we would be obligated to pay for our share of the costs of closure of the generating facility including costs associated with decommissioning, remediation, reclamation and restoration of the property, and any costs of terminating contracts associated with the generating facility, such as coal supply arrangements. In the event of a sale of our interest in a generating facility, we may not be able to negotiate the sale on favorable terms, which could result in the recognition of a loss on the sale and other potential liabilities. There can be no assurance that we would be authorized by any of our state utility commissions to recover any costs or losses associated with the early closure of or sale of our interest in a generating facility.

The loss of a major generating facility would require OTP to identify and obtain approval for other sources of generation for its customers, if available, and expose it to higher purchased power costs. In addition, OTP may not be able to obtain timely regulatory approval for new generation resources to replace closed or sold facilities.

In September 2021, our IRP filed in the three jurisdictions in which we operate outlined our plan to withdraw from our 35 percent ownership interest in Coyote Station, a jointly-owned coal-fired generation plant, by December 31, 2028. If we proceed with the withdrawal under the updated IRP which we expect to file in March 2023, we will seek to recover all costs related to the future withdrawal from Coyote Station, however, there can be no assurance that we will be granted recovery of any such costs. A full or partial denial of recovery of the costs of withdrawal could significantly impact our operating results, financial condition and liquidity.

Federal and state environmental regulation could require us to incur substantial capital expenditures, increased operating costs or make it no longer economically viable to operate some of our facilities.
We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements may require us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines.

Coyote Station, one of OTP's jointly-owned coal-fired power plants, is subject to assessment under the second implementation period of RHR as part of the state of North Dakota's state implementation plan, or SIP. We cannot predict with certainty the impact the SIP may have on our business until the plan has been approved or otherwise acted on by the EPA, including its potential implementation of an alternative federal implementation plan. However, significant emission control investments could be required. Alternatively, investments in emission control equipment may prove to be uneconomic and result in the early closure of or the sale of our interest in Coyote Station.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. The multiple jurisdictions that govern our electric utility business may not agree as to the appropriate resource mix, which may lead to costs incurred to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our financial condition, operating results and liquidity, making the operation of some of our facilities no longer economically viable.

Legislation, regulation, litigation or other actions related to climate change and greenhouse gas emissions could materially impact us.
Current and future federal, state, regional and international regulations to address global climate change and reduce GHG emissions, including measures such as mandated levels of renewable generation, mandatory reductions in CO_2 emission levels, taxes on CO_2 emissions, or cap-and-trade regimes, could require us to incur significant costs which could negatively impact our financial condition, operating results and liquidity if such costs cannot be recovered through rates granted by rate-making authorities or through increased market prices for electricity.

In 2021, the Biden Administration introduced new targets aimed at reducing economy-wide net GHG emissions by 50 to 52 percent from 2005 levels by 2030. In addition, the Administration set a goal to reach 100 percent carbon pollution-free electricity by 2035. To achieve these targets the Administration may implement new regulations targeting GHG emissions from existing fossil fuel-fired power plants. While the precise nature and implications of any new regulations are uncertain, such regulations could impose substantial costs on and impact the operations of our utility business, which may materially impact our financial condition, operating results and liquidity.

In addition to complying with legislation and regulation, we could be subject to litigation related to climate change. In recent years, there has been an increase in litigation against electric utilities and fossil fuel producers. If OTP were subjected to such litigation, the costs of such litigation could be significant and an adverse outcome could require substantial capital expenditures, changes in operations and possible payment of penalties or damages which could affect our financial condition, operating results and liquidity if the costs are not recoverable in rates or covered by insurance.

To the extent investors view climate change, fossil fuel combustion and GHG emissions as a financial risk, our stock price or our ability to access capital markets on favorable terms and conditions could be adversely impacted.

Violations of extensive legal and regulatory compliance requirements could have a negative impact on our business and results of operations.
We are subject to an extensive legal and regulatory framework imposed under federal and state laws and regulatory agencies, including the FERC and the NERC. We could be subject to potential financial penalties for compliance violations. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. If a serious reliability incident were to occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance. We attempt to mitigate the risk of regulatory penalties through formal training. However, there is no guarantee our compliance program will be sufficient to ensure against violations.

In addition, energy policy initiatives at the state or federal level could increase incentives for distributed generation, or authorize municipal utility formation or acquisition of service territory, or local initiatives could introduce generation or distribution requirements that could change the current integrated utility model.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary approvals for our existing operations and that our business is conducted in accordance with applicable laws and regulatory requirements; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations or the imposition of additional regulations could have a material adverse impact on our financial condition, operating results and liquidity.

Our transmission and generation facilities could be vulnerable to cyber and physical attack.
OTP owns electric transmission and generation facilities subject to mandatory and enforceable standards advanced by the NERC. These bulk electric system facilities provide the framework for the electrical infrastructure of OTP’s service territory and interconnected systems, the operation of which is dependent on information technology systems. Further, the information systems that operate OTP’s electric system are interconnected to external networks. Parties that wish to disrupt the U.S. bulk power system or OTP’s operations could view OTP’s computer systems, software or networks as attractive targets for cyber-attack.

In addition, OTP’s generation and transmission facilities are spread throughout a large service territory. These facilities could be subject to physical attack or vandalism that could disrupt OTP’s operations or conceivably the regional or U.S. bulk power system.

OTP is subject to mandatory cybersecurity and physical security regulatory requirements. OTP implements the NERC standards for operating its transmission and generation assets and remains abreast of best practices within the business and the utility industry to protect its computers and computer-controlled systems from outside attack. We rely on industry-accepted security measures and technology to securely maintain confidential and proprietary information necessary for the operation of our systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls and disaster recovery plans designed to protect and preserve the confidentiality, integrity and availability of data and systems. We also take prudent and reasonable steps to protect the physical security of our generation and transmission facilities. However, all these measures and technology may not adequately prevent security breaches, ransomware attacks or other cyber-attacks, or enable us to recover effectively from such a breach or attack. Any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches or physical attack of our generation or transmission facilities could adversely affect our business and our financial condition, operating results and liquidity.

Our generating facilities and transmission assets are subject to operational risks that could result in unscheduled outages and increased costs.
The operation of electric generating facilities and transmission assets involves many risks including facility shutdowns due to equipment or process failures; aging equipment and sourcing replacement parts; labor disputes; operator error; catastrophic events such as fires, explosions and floods;

the dependence on a specific fuel source; increased costs or delayed receipt of materials due to supply chain disruptions; and the risk of performance below expected levels of output or efficiency. We could be subject to costs associated with any unexpected failure to produce or deliver power, including failures caused by a breakdown or forced outage, as well as damages to facilities or other assets.

We rely on a limited number of suppliers to provide coal and coal transportation to our facilities. A failure to perform by any of these counterparties may arise due to liquidity challenges or insolvency, operational deficiencies or other circumstances such as severe weather or natural disasters, which could impact our ability to provide service to our customers or require us to seek alternative sources for these products and services, if available, which could lead to increased costs adversely impacting our financial condition, operating results and liquidity.

Joint ownership of coal-fired generation facilities could impact our ability to manage changing regulations and economic conditions.
We own our coal-fired generation facilities jointly with other co-owners with varying ownership interests in such facilities. Our ability to make determinations on our IRP in order to best navigate changing environmental regulations and economic conditions may be impacted by our rights and obligations under the co-ownership agreements and related agreements, and our ability to reconcile a divergence in the interests of OTP and the co-owners of these generation facilities. Such a divergence could impair our ability to effectively manage these changing conditions to meet our strategic objectives and could adversely impact our financial condition, operating results and liquidity.

We are subject to risks associated with energy markets.
Our electric business is subject to the risks associated with energy markets, including market supply and changing energy prices. If we are faced with shortages in market supply, we may be unable to fulfill our contractual obligations to our retail, wholesale and other customers at previously anticipated costs. This could force us to obtain alternative energy or fuel supplies at higher costs, or suffer increased liabilities for unfulfilled contractual obligations. Any significantly higher than expected energy or fuel costs could negatively affect our financial condition, operating results and liquidity.

MANUFACTURING SEGMENT RISKS

The price and availability of raw materials could adversely impact our operating results.
The companies in our Manufacturing segment use a variety of raw materials in the products they manufacture including, among others, steel, aluminum, and polystyrene and other plastics resins. The price and availability of the raw materials used in our manufacturing processes are based on global supply and demand conditions, which can create volatile pricing and supply disruptions as conditions change. Federal trade policies, including imposed tariffs, can also impact prices for these raw materials. If we are unable to pass cost increases through to our customers or are unable to procure adequate or timely raw material inputs for use in our manufacturing processes, our financial condition, operating results and liquidity could be negatively impacted.

Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes used by our manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of our manufacturing companies as it reduces their ability to mitigate the cost associated with excess material.

Competition from foreign and domestic manufacturers could affect the revenues and earnings of our manufacturing businesses.
Our manufacturing businesses are subject to intense competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development personnel and facilities, and other capabilities. Our ability to compete on product performance, competitive pricing, technological innovation and customer service is critical to our ongoing success. If we are unable to compete in these and potentially other areas, our business and financial condition, operating results and liquidity could be adversely impacted.

Economic conditions in the end markets in which our customers operate could have an adverse impact on our operating results and liquidity.
Our manufacturing businesses derive a large amount of their revenues from customers in the following industry sectors: recreational vehicle/ powersports, lawn and garden, construction, agriculture, energy and horticulture. Factors affecting any of these industries in general could adversely affect our operating results as growth in our operating revenues is largely dependent on the growth of our customers' businesses in their respective industries. These factors include:

- seasonality of demand for our customers' products which may cause our manufacturing capacity to be underutilized for periods of time;
- our customers' failure to successfully market their products, gain or retain widespread commercial acceptance of their products or compete effectively in their industries;
- loss of market share for our customers' products which may lead our customers to reduce or discontinue purchasing our products and components and to reduce prices, thereby exerting pricing pressure on us;
- economic conditions in the markets in which our customers operate, the United States, in particular, including recessionary periods such as a global economic downturn;
- our customers' decisions to bring the production of components in-house that have traditionally been outsourced to us; and
- product design changes or manufacturing process changes that may reduce or eliminate demand for the components we supply.

We expect future sales will continue to depend on the success of our customers. If economic conditions or demand for our customers' products deteriorates, we may experience a material adverse effect on our financial condition, operating results and liquidity.

Our business may be adversely affected if we are not able to maintain our manufacturing, engineering and technological expertise.
The markets for our manufacturing businesses are characterized by changing technology and evolving process development. The continued success of our businesses will depend on our ability to:

- maintain technological leadership in our industry;

- implement new and expand on current robotics, automation and tooling technologies; and
- anticipate or respond to changes in manufacturing processes in a cost-effective and timely manner.

We may be unable to develop the capabilities required by our customers in the future. The emergence of new technologies, industry standards or customer requirements may render our equipment, inventory or processes obsolete or noncompetitive. We may be required to acquire new technologies and equipment to remain competitive. The acquisition and implementation of new technologies and equipment may require us to incur significant expense and capital investment, which could reduce our margins and affect our operating results. When we establish or acquire new facilities, we may not be able to maintain or develop our manufacturing, engineering and technological expertise due to a lack of trained personnel, ineffective training of new staff or technical difficulties with machinery. Failure to anticipate and adapt to customers' changing technological needs and requirements and to maintain manufacturing, engineering and technological expertise may have material adverse effects on our financial condition, operating results and liquidity.

PLASTICS SEGMENT RISKS

Changes in PVC resin prices could negatively affect our plastics business.
The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices were rising or stable, margins and sales volumes were higher and when resin prices were falling, sales volumes and margins were lower. Changes in PVC resin prices can negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of our finished goods inventory.

Periodic shortages of PVC resin coupled with robust domestic and global demand for PVC resin led to significantly increased resin pricing throughout 2021 and the first half of 2022, which resulted in higher input costs in our Plastics segment during these years. Resin prices started to decline in the last half of 2022 and we anticipate resin prices will moderate in 2023 as these market conditions normalize. Our operating results could be impacted by the timing and degree to which resin prices stabilize.

Our plastics operations are highly dependent on a limited number of vendors and a limited supply of PVC resin and other materials.
We rely on a limited number of vendors to supply the PVC resin used in our plastics business. In 2022 we sourced all of our PVC resin needs from two vendors. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region. This could increase the risk of a shortage of resin in the event of a hurricane, other extreme weather events and other natural disasters in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources were available.

Although PVC resin is the most significant raw material input in our PVC pipe manufacturing process, we also use certain other materials, such as stabilizers, gaskets, lumber, banding and others in the process of manufacturing and shipping our PVC pipe products. We generally source these materials from a limited number of suppliers and any significant supply chain constraints or disruptions related to these materials could also disrupt our ability to manufacture or ship products and could result in increased costs.

We compete against many other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.
The plastic pipe industry is fragmented and competitive due to the number of producers and the fungible nature of the product. We compete not only against other plastic pipe manufacturers, but also against ductile iron, steel and concrete pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope and the principal areas of competition are a combination of price, service, warranty and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics businesses.

External factors beyond our control could cause fluctuations in demand for our PVC pipe products and changes in our prices and margins, which could adversely impact our operating results.
Our PVC pipe products, sold through distributors and wholesalers, are primarily used in municipal and rural water projects, wastewater projects, storm drainage systems and reclamation systems. External factors beyond our control can cause volatility in raw material costs, demand for our products, sales prices, and deterioration in operating margins. These factors can magnify the impact of economic cycles on our business and results of operations. Examples of external factors include:

- general economic conditions including housing and construction markets which can be cyclical;
- increases in interest rates;
- severe weather and natural disasters;
- governmental regulation in the United States;
- funding shortages for municipal water and wastewater projects; and
- pandemics and other public health threats.

Our financial results in 2021 and 2022 were impacted by unique market conditions within the PVC pipe industry, including a significant increase in the price of PVC resin, and periodic shortages of certain additives and ingredients used in the manufacturing of PVC pipe which limited the manufacturing of PVC pipe. Strong demand for PVC pipe along with limited manufacturing output led to low inventories across the industry. The combination of these factors resulted in extraordinary growth in earnings and cash flows from our Plastic segment in these years. As these industry conditions begin to normalize in 2023 and beyond, we anticipate our operating results and cash flows will moderate, returning to more stable levels. Our operating results and cash flows could be impacted by the timing under which conditions normalize and the level of stabilized resin and PVC pipe prices.

GENERAL RISK FACTORS

Economic conditions could negatively impact our businesses.
Our businesses are affected by local, national and worldwide economic conditions, including the impact of inflation, tightening of credit in financial markets, economic recessions or other changes in economic conditions. Our businesses may be adversely affected by decreases in the general level of economic activity, such as decreases in business and consumer spending. A decline in the level of economic activity and uncertainty regarding energy and commodity prices could adversely affect our results of operations and our future growth. Inflationary pressures may lead to rising material and commodity costs and increased labor costs. Our operating results and liquidity would be adversely impacted if we were unable to recover these increased costs from our customers. Tightening of credit in financial markets could adversely affect the ability of customers to finance purchases of our goods and services, resulting in decreased orders, cancelled or deferred orders, slower payment cycles, and increased bad debt and customer bankruptcies.

If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.
We expect much of our growth in the next few years will come from major capital investments at existing companies. To achieve the organic growth we expect, we must have access to the capital markets, be successful with capital expansion programs related to organic growth, develop new products and services, expand our markets and increase efficiencies in our businesses. Competitive and economic factors could adversely affect our ability to do this. If we are unable to achieve and sustain consistent organic growth, we will be less likely to meet our earnings growth targets, which may adversely affect the market price of our common shares.

The economic effects of the coronavirus (COVID-19) pandemic and any other epidemic or pandemic, and measures taken to reduce and slow the spread of the disease could adversely impact our business.
The outbreak and global spread of COVID-19 has had widespread impacts on society, economies, financial markets and businesses everywhere since early 2020. The COVID-19 pandemic has impacted our business operations, including our employees, customers, construction contractors, suppliers and vendors, and some uncertainty in the nature and degree of the continued effects over time still remains. In 2022, our business was impacted by supply chain disruptions and labor shortages resulting from the pandemic, and the associated costs and inflation related thereto. The extent to which COVID-19 impacts our business going forward, if at all, remains uncertain.

We continue to monitor developments involving our workforce, customers, construction contractors, suppliers and vendors and take steps to mitigate against additional impacts, but given the unprecedented and evolving nature of these circumstances, we cannot predict the full extent of the impact that COVID-19 will have on our operating results, financial condition and liquidity.

A future widespread outbreak of an infectious disease, which affects a large percentage of the population regionally, nationally, or globally could impact our business operations, including our employees, customers, construction contractors, suppliers and vendors, and could impact our operating results, financial condition and liquidity.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The following provides a summary of our properties which are material to our operations, by segment, as of December 31, 2022.

ELECTRIC SEGMENT

The following reflects our wholly- or jointly-owned material electric generation facilities as of December 31, 2022:

Description	*Location*	*Year Placed in Service*	*Fuel Type*	*Capacity - kW (Nameplate Rating)*
Big Stone Plant[1]	Big Stone City, SD	1975	Subbituminous Coal	223,146
Coyote Station[2]	Beulah, ND	1981	Lignite Coal	144,900
Jamestown Combustion Turbine	Jamestown, ND	1975	Fuel Oil	48,108
Lake Preston Combustion Turbine	Lake Preston, SD	1978	Fuel Oil	24,100
Solway Combustion Turbine	Solway, MN	2003	Natural Gas/Fuel Oil	44,500
Astoria Station	Astoria, SD	2021	Natural Gas	245,000
Langdon Wind Center	Cavalier County, ND	2007	Wind	40,500
Ashtabula Wind Center	Barnes County, ND	2008	Wind	48,000
Luverne Wind Farm	Griggs and Steele Counties, ND	2009	Wind	49,500
Merricourt Wind Energy Center	McIntosh and Dickey Counties, ND	2020	Wind	150,000

(1)OTP holds a 53.9% joint ownership interest in this jointly-owned facility. The nameplate capacity indicated reflects OTP's ownership percentage.

(2)OTP holds a 35.0% joint ownership interest in this jointly-owned facility. The nameplate capacity indicated reflects OTP's ownership percentage.

On January 3, 2023, OTP purchased the Ashtabula III wind farm, a 62.4-megawatt wind farm located in eastern North Dakota.

In addition to our generation facilities, we wholly or jointly own transmission and distribution lines as of December 31, 2022 as follows:

	Miles
Transmission	
345 kV[(3)]	875
230 kV[(4)]	484
115 kV	960
Less than 115 kV	4,028
Distribution	
Less than 115 kV	8,413

[(3)] *As of December 31, 2022, OTP held a 14.2% ownership interest of 242 miles, a 4.8% ownership interest of 250 miles, and a 50.0% ownership interest of 234 miles of the 345 kV transmission lines, with the remaining miles being wholly-owned.*

[(4)] *As of December 31, 2022, OTP held a 14.8% ownership interest of 70 miles of the 230 kV transmission lines, with the remaining miles being wholly-owned.*

MANUFACTURING AND PLASTICS SEGMENTS

The following reflects the material properties of our Manufacturing and Plastic segments as of December 31, 2022:

Segment/Location	*Owned/Leased*	*Facility Type/Use*	*Approximate Square Feet*
Manufacturing Segment			
Washington, IL	Leased	Office/Manufacturing/Warehouse	217,508
Detroit Lakes, MN	Owned	Office/Manufacturing/Warehouse	353,812
Lakeville, MN	Leased	Office/Manufacturing/Warehouse	413,000
Dawsonville, GA	Owned	Office/Manufacturing/Warehouse	172,000
Buford, GA	Leased	Warehouse	71,357
Clearwater, MN	Owned	Office/Manufacturing/Warehouse	203,840
Otsego, MN	Leased	Manufacturing/Warehouse	86,400
Plastics Segment			
Fargo, ND	Owned	Office/Manufacturing/Warehouse	122,441
Fargo, ND	Leased	Warehouse	239,580
Phoenix, AZ	Owned	Office/Manufacturing/Warehouse	86,066

We believe the facilities described above are adequate for our present business.

ITEM 3. LEGAL PROCEEDINGS

We are the subject of various legal and regulatory proceedings in the ordinary course of our business. See Note 13, *Commitments and Contingencies*, to the consolidated financial statements, and Management's Discussion and Analysis of Financial Condition and Results of Operations, *Regulatory Matters*, which information is incorporated herein by reference, for discussion of certain legal, environmental and other regulatory proceedings to which we are a party.

ITEM 3A. INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Set forth below is a summary of the principal occupations and business experience during the past five years of the executive officers as defined by rules of the SEC. Each of the executive officers has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly-owned subsidiary, Otter Tail Power Company.

Name and Age	*Date Elected to Office*	*Current Position*
Charles S. MacFarlane (58)	04/13/15	President and Chief Executive Officer
Kevin G. Moug (63)	04/09/01	Chief Financial Officer and Senior Vice President
Timothy J. Rogelstad (56)	04/14/14	Senior Vice President, Electric Platform
John S. Abbott (64)	02/11/15	Senior Vice President, Manufacturing Platform
Jennifer O. Smestad (52)	01/01/18	Vice President, General Counsel and Corporate Secretary

Chuck MacFarlane has served as the Company’s President and Chief Executive Officer and as a member of the Company’s Board of Directors since April 13, 2015.

Kevin Moug has served as Chief Financial Officer and Senior Vice President of the Company since April 9, 2001.

Timothy Rogelstad has served as President of OTP and Senior Vice President, Electric Platform of the Company since April 14, 2014.

John Abbott has served as Senior Vice President, Manufacturing Platform, since February 5, 2015.

Jennifer Smestad has served as Vice President, General Counsel and Corporate Secretary of the Company, since January 1, 2018. Ms. Smestad has also served as General Counsel for OTP since March 1, 2013.

The term of office for each of the executive officers is one year and any executive officer elected may be removed by the vote of the board of directors at any time during the term. There are no family relationships between any of the executive officers or directors.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

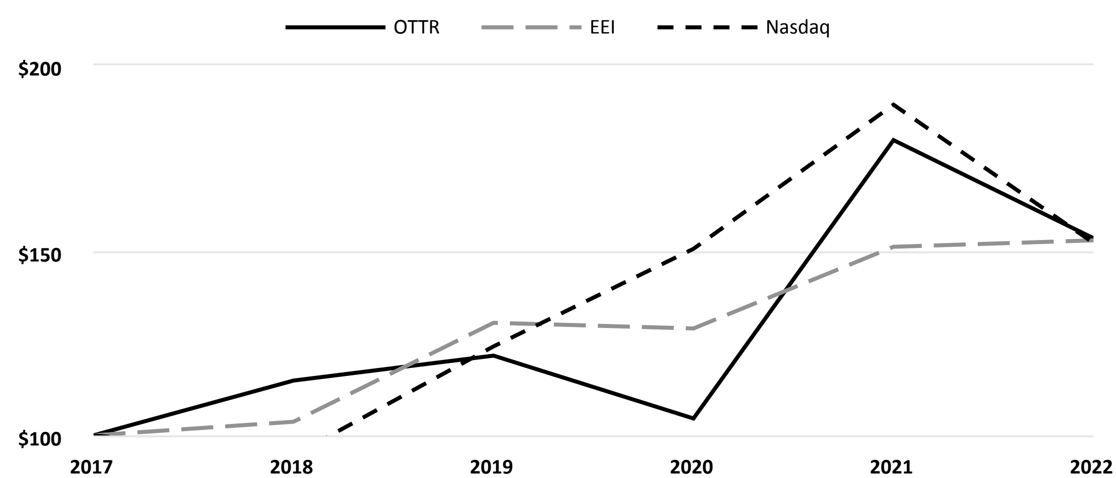
PART II

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

Our common stock is traded on the Nasdaq Global Select Market under the Nasdaq symbol "OTTR". As of December 31, 2022, there were 11,748 holders of record of our common stock.

We do not have a publicly announced stock repurchase program and we did not repurchase any equity securities during the year ended December 31, 2022.

PERFORMANCE GRAPH COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
This graph compares the cumulative total shareholder return on our common shares for the last five years with the cumulative return of the Nasdaq Stock Market Index and the Edison Electric Institute (EEI) Index over the same period (assuming the investment of $100 in each vehicle on December 31, 2017, and reinvestment of all dividends).



		2017		*2018*		*2019*		*2020*		*2021*		*2022*
OTTR	$	100.00	$	114.80	$	121.54	$	104.56	$	179.79	**$**	**153.27**
EEI	$	100.00	$	103.67	$	130.41	$	128.89	$	150.96	**$**	**152.70**
Nasdaq	$	100.00	$	94.56	$	124.03	$	150.41	$	189.36	**$**	**152.00**

ITEM 6. [RESERVED]

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

You should read the following discussion and analysis of our financial condition and results of operations together with our financial statements and the related notes appearing under Item 8 of this Form 10-K.

OVERVIEW

Otter Tail Corporation and its subsidiaries form a diverse group of businesses with operations classified into three segments: Electric, Manufacturing and Plastics. Our Electric business is a vertically integrated, regulated utility with generation, transmission and distribution facilities to serve our customers in western Minnesota, eastern North Dakota and northeastern South Dakota. Our Manufacturing segment provides metal fabrication for custom machine parts and metal components, and manufactures extruded and thermoformed plastic products. Our Plastics segment manufactures PVC pipe for use in, among other applications, municipal and rural water, wastewater and water reclamation projects.

Our strategy includes investing in rate base growth opportunities in our Electric segment and capitalizing on organic growth opportunities in our Manufacturing and Plastics segments. Investments in our Electric segment are expected to produce increased earnings and cash flows, lower our overall risk, create a more predictable earnings stream, improve our credit quality and preserve our ability to fund our dividend. Our Electric segment is complemented by our Manufacturing and Plastics segment businesses, which we expect to contribute to earnings growth by capitalizing on market expansion opportunities and increasing utilization of existing capacities, along with planned investments to create additional capacity and increased efficiencies. Collectively, our mix of businesses is expected to contribute to the achievement of our targeted annual growth in earnings per share of five to seven percent over the next several years, using 2024 as the base for measurement.

2022 FINANCIAL RESULTS

In 2022, our diversified business model generated record financial results, producing net income of $284.2 million, or $6.78 per diluted share, an increase of 61% from $176.8 million, or $4.23 per diluted share, in 2021. All three of our operating segments produced double digit earnings growth in 2022 compared to the prior year, led by our Plastics segment, which capitalized on the continuation of unique market conditions to produce extraordinary financial results. In 2022, we paid an annual dividend of $1.65 per share, or $68.8 million, completing our 84th consecutive year of dividend payments to our shareholders.

Our Electric segment produced earnings growth of 10% in 2022, driven by increased customer demand from commercial and industrial customers, including the addition of a new large commercial customer in North Dakota, and the impacts of favorable weather. We continued the construction of rate base investments, including our Hoot Lake Solar project, which we anticipate will be in commercial operation by the end of 2023. Our utility also accomplished all of its key regulatory objectives for the year, including completing a general rate case in Minnesota, with final rates becoming effective on July 1, 2022, and securing all necessary approvals to acquire the Ashtabula III wind farm, which was finalized and purchased on January 3, 2023.

Our Manufacturing segment produced earnings growth in 2022 of 22%, as strong end market demand across most markets we serve led to increased sales volumes. Pricing increases and favorable cost absorption offset increased labor, material, and overhead costs, which resulted in consistent gross profit levels. Our Manufacturing segment was also impacted in 2022 by steel price volatility, as further discussed below.

Our Plastics segment produced earnings of $195.4 million in 2022, compared to $97.8 million in 2021. The unprecedented level of earnings in 2022 resulted from extraordinary industry supply and demand dynamics which emerged in 2021 and continued into 2022. As further described below, increases in the price of resin, the primary raw material used in the manufacturing of PVC pipe, coupled with robust end market demand for PVC pipe led to a rapid escalation in PVC pipe prices and gross margins in 2021 and into 2022. Resin prices declined from peak levels in the second half of the year, and pipe distributors and contractors reduced purchase volumes and inventory levels in response to changing market conditions. Despite softening demand in the second half of the year, strong pipe sales prices and profit margins resulted in earnings growth of 100% in 2022.

Our earnings mix in 2022 was 28% from our Electric segment and 72% from the combination of our Manufacturing and Plastics segments net of unallocated corporate costs. Electric segment earnings as a percentage of our total earnings were less than our long-term target of 65% due to the unique market conditions that occurred in our Plastics segment. We expect our earnings mix to return to our targeted mix of 65% from the Electric segment and 35% from the Manufacturing and Plastics segments in 2024.

STEEL PRICING

Volatility in the price of steel, a key material input to our Manufacturing segment, significantly impacted our operating results in 2022. Steel prices increased rapidly throughout 2021, peaking in the fourth quarter at historically high levels. Steel prices, which were highly volatile in 2022, began to steadily decline at the end of the second quarter and returned to near historical levels by the end of the year. The increase in steel prices led to increased sale prices for our products at BTD, our metal fabrication business within our Manufacturing segment, as we passed along material cost increases to our customers. Scrap metal prices, which typically follow steel prices, also increased throughout 2021 and remained elevated in the first half of 2022, but declined sharply throughout the second half of the year, negatively impacting our 2022 financial results.

PVC PIPE SUPPLY AND DEMAND CONDITIONS

PVC resin is the primary material input of the PVC pipe manufactured by our Plastics segment businesses. Resin supply disruptions throughout 2021, along with robust domestic and global demand for PVC resin, led to significantly increased resin prices. Supply disruptions for resin and other additives and ingredients used in the manufacturing process also resulted in reduced manufacturing of PVC pipe and low pipe inventories across the industry. This combination of disrupted raw material supply and the resulting low PVC pipe inventories, along with robust demand for PVC pipe, led to rapidly increasing sale prices for PVC pipe throughout 2021 and 2022. The increase in sale prices outpaced the increase in PVC resin costs and led to expanding gross profit margins which positively impacted our 2022 financial results. However, beginning in the third quarter of 2022, demand for PVC pipe began to decline as PVC pipe distributors and contractors reduced purchase volumes and inventory levels in response to changing market conditions.

The unique market dynamics experienced by our Plastics segment businesses in 2021 and 2022 resulted in a significant increase in earnings compared to prior periods. We currently expect earnings of our Plastics segment to decrease in 2023, but to remain elevated relative to historical levels. We currently expect segment earnings to normalize in 2024, as industry supply and demand conditions normalize throughout 2023.

The marketplace dynamics impacting both our Manufacturing and Plastics segments are fluid and subject to change which may impact our operating results prospectively.

FINANCIAL AND OTHER METRICS

Heating Degree Days (HDDs) is a measure of how much (in degrees), and for how long (in days), the outside air temperature was below a certain normalized level. Normal weather conditions are defined as the 20-year average of actual historical weather conditions. This measure is commonly used in calculations relating to the energy consumption required to heat buildings.

Cooling Degree Days (CDDs) is a measure of how much (in degrees), and for how long (in days), the outside air temperature was above a certain normalized level. This measure is commonly used in calculations relating to the energy consumption required to cool buildings.

OTP generally bases its forecasted kwh sales and rates on expected consumption under a normal level of HDDs and CDDs over a given period of time in its service territory. Increased or decreased levels of consumption for certain customer classifications are attributed to deviation from the norms and are a significant factor influencing consumption of electricity across our service territory. We present HDDs and CDDs to provide an indication of the impact of weather on kwh sales, revenues and earnings relative to forecast and on period-to-period results.

Utility Rate Base is the value of property on which a public utility is permitted to earn a specified rate of return in accordance with rules set by a regulatory agency. In general, rate base consists of the value of property used by the utility in providing service. Rate base can also include cash, working capital, materials and supplies, deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits dependent on the method that is used in the calculation, which can vary from jurisdiction to jurisdiction. We present actual and forecasted levels of utility rate base to provide an indication of expected investments on which we expect to earn future returns.

RESULTS OF OPERATIONS

For a comparison of fiscal year 2021 to 2020, see Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our report on Form 10-K for the fiscal year ended December 31, 2021, filed with the SEC on February 16, 2022.

Provided below is a summary and discussion of our operating results on a consolidated basis followed by a discussion of the operating results of each of our segments, Electric, Manufacturing and Plastics. In addition to the segment results, we provide an overview of our Corporate costs. Our Corporate costs do not constitute a reportable segment but rather consist of unallocated general corporate expenses, such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of segment performance. Corporate costs are added to operating segment totals to reconcile to totals on our consolidated statements of income.

CONSOLIDATED RESULTS

The following table summarizes our consolidated results of operations for the years ended December 31, 2022 and 2021:

(in thousands)	*2022*	*2021*	*$ change*	*% change*
Operating Revenues	**$ 1,460,209**	$ 1,196,844	$ 263,365	22.0 %
Operating Expenses	**1,069,770**	947,136	122,634	12.9
Operating Income	**390,439**	249,708	140,731	56.4
Interest Charges	**36,016**	37,771	(1,755)	(4.6)
Nonservice Cost Components of Postretirement Benefits	**(1,075)**	2,016	(3,091)	(153.3)
Other Income	**2,037**	2,900	(863)	(29.8)
Income Before Income Taxes	**357,535**	212,821	144,714	68.0
Income Tax Expense	**73,351**	36,052	37,299	103.5
Net Income	**$ 284,184**	$ 176,769	$ 107,415	60.8 %

Operating Revenues increased $263.4 million on a consolidated basis in 2022. Each operating segment contributed to the overall growth. Electric segment operating revenues increased 14% primarily due to increased fuel recovery revenues and higher sales volumes. Manufacturing segment operating revenues increased 18% mainly as a result of higher sales volumes and increased pricing to pass through material input costs. Plastics segment operating revenues increased 35% due to an increase in the price per pound of PVC pipe sold, partially offset by decreased sales volumes. See our segment disclosures below for additional discussion of items impacting operating revenues.

Operating Expenses increased $122.6 million in 2022. Electric segment operating expenses increased 17% primarily due to increased purchased power costs resulting from increased purchase volumes and higher operating and maintenance expenses. Operating expenses in our Manufacturing segment increased 18%, driven by increased cost of products sold, which resulted from higher material input costs and increased sales volumes. Operating expenses in our Plastics segment were consistent year over year due to lower sales volumes which were offset by higher costs of products sold from higher resin costs and increased operating costs. See our segment disclosures below for additional discussion of items impacting operating expenses.

Interest Charges decreased $1.8 million in 2022 primarily due to a decrease in our average short-term borrowings, partially offset by increased interest rates on our short-term borrowings and a net increase in our long-term debt of $60.0 million. The increase in our long-term debt was largely used to finance rate base investments in our Electric segment.

Nonservice Cost Components of Postretirement Benefits decreased $3.1 million in 2022 primarily due to the amortization of actuarial gains resulting from the increase in the discount rates used to measure our pension benefit and other postretirement benefit liabilities as of December 31, 2021.

Other Income decreased $0.9 million in 2022 primarily due to investment losses on our corporate-owned life insurance policies and the investments of our captive insurance entity.

Income Tax Expense increased $37.3 million in 2022 primarily due to an increase in income before income taxes. Our effective tax rate was 20.5% in 2022 and 16.9% in 2021. See Note 12 to our consolidated financial statements included in the report on Form 10-K for additional information regarding factors impacting our effective tax rate.

ELECTRIC SEGMENT RESULTS

The following table summarizes the operating results of our Electric segment for the years ended December 31, 2022 and 2021:

(in thousands)	*2022*	*2021*	*$ change*	*% change*
Retail Sales Revenue	**$ 470,300**	$ 405,484	$ 64,816	16.0 %
Transmission Services Revenues	**52,213**	48,835	3,378	6.9
Wholesale Revenues	**18,539**	17,936	603	3.4
Other Electric Revenues	**8,647**	8,066	581	7.2
Total Operating Revenue	**549,699**	480,321	69,378	14.4
Production Fuel	**65,110**	59,327	5,783	9.7
Purchased Power	**100,281**	65,409	34,872	53.3
Operating and Maintenance Expenses	**181,378**	159,669	21,709	13.6
Depreciation and Amortization	**72,050**	71,343	707	1.0
Property Taxes	**17,742**	17,609	133	0.8
Operating Income	**$ 113,138**	$ 106,964	$ 6,174	5.8 %

Electric kwh Sales *(in thousands)*				
Retail kwh Sales	**5,592,368**	4,789,879	802,489	16.8 %
Wholesale kwh Sales	**267,184**	420,044	(152,860)	(36.4)
Heating Degree Days	**7,122**	5,794	1,328	22.9
Cooling Degree Days	**531**	704	(173)	(24.6)

Our Electric segment operating results are impacted by fluctuations in weather conditions and the resulting demand for electricity for heating and cooling. The following table presents heating and cooling degree days as a percent of normal for the years ended December 31, 2022 and 2021:

	2022	*2021*
Heating Degree Days	**112.5 %**	91.3 %
Cooling Degree Days	**113.5 %**	151.7 %

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kwh sales under actual weather conditions and expected retail kwh sales under normal weather conditions for the years ended December 31, 2022 and 2021, and between years:

	2022 vs Normal	*2022 vs 2021*	*2021 vs Normal*
Effect on Diluted Earnings Per Share	$ 0.11	$ 0.10	$ 0.01

Retail Revenues increased $64.8 million primarily due to the following:

- A $42.5 million increase in fuel recovery revenues primarily due to increased purchased power volumes and pricing to recover production fuel costs, as described below.
- A $12.8 million increase in retail revenues from increased sales volumes from commercial and industrial customers, including the impact of a new commercial customer load in North Dakota.
- A $5.4 million increase in revenues from the favorable impact of weather compared to last year.
- A $4.1 million increase in interim rate revenue due to the finalization of the interim rate refund, as approved by the MPUC in the second quarter of 2022.

Retail revenues also benefited from increased transmission, renewable and phase-in rider revenue in 2022. These increases were partially offset by a decrease in CIP revenue as a result of decreased CIP spending and related cost recovery.

Transmission Services Revenues increased $3.4 million primarily due to increased recovery of higher transmission costs and increased transmission investments along with increased transmission volumes and formula rate adjustments.

Production Fuel costs increased $5.8 million due to a 22% increase in fuel cost per kwh, which was partially offset by a decrease in kwhs generated from our fuel-burning plants due to an outage at Coyote Station in 2022, and the retirement of Hoot Lake Plant in May 2021.

Purchased Power costs to serve retail customers increased $34.9 million due to a 54% increase in the volume of purchased power, resulting from outages at both Coyote Station and Big Stone Plant, the retirement of Hoot Lake Plant and increased customer demand.

Operating and Maintenance Expense increased $21.7 million primarily due to:

- A $6.7 million increase in employee compensation and benefit costs, including discretionary incentive and retirement benefit compensation based on current year financial results.
- A $3.7 million increase in transmission tariff expenses.
- A $3.3 million increase in maintenance and other costs due to our plant outages at Coyote Station and Big Stone Plant during the year.
- A $1.4 million increase in travel costs driven by higher fuel costs for our vehicle fleet and increased travel activities.
- Other additional costs including additional maintenance costs, increases in information technology expenses, increases in insurance costs and various other expenses.

These expense increases were partially offset by, among other items, a $2.1 million reduction in CIP expenses compared to the previous year.

MANUFACTURING SEGMENT RESULTS

The following table summarizes operating results of our Manufacturing segment for the years ended December 31, 2022 and 2021:

(in thousands)	*2022*	*2021*	*$ change*	*% change*
Operating Revenues	**$ 397,983**	$ 336,294	$ 61,689	18.3 %
Cost of Products Sold	**315,375**	259,581	55,794	21.5
Other Operating Expenses	**37,341**	37,163	178	0.5
Depreciation and Amortization	**16,202**	15,436	766	5.0
Operating Income	**$ 29,065**	$ 24,114	$ 4,951	20.5 %

Operating Revenues increased $61.7 million primarily due to the following:

- At BTD, operating revenues increased $52.8 million due to a combination of higher sales volumes and increased pricing. Sales volumes increased 12% compared to the previous year due to strong end market demand. Material costs, which are passed through to customers, increased 8%, as annual steel prices increased from the previous year. Steel prices increased drastically in 2021, peaking in the fourth quarter, and remained elevated compared to historical levels throughout the first half of 2022. Increases in sales volumes and prices were partially offset by a $2.5 million decrease in scrap revenues due to a decrease in both scrap metal prices and scrap volumes.
- At T.O. Plastics, revenues increased $8.8 million due to a combination of increased sales prices and higher sales volumes. Sales prices increased 16% and sales volumes increased 7% due to strong customer demand primarily in horticulture product sales.

Cost of Products Sold increased $55.8 million due to the following:

- Cost of products sold at BTD increased $50.2 million primarily due to higher sales volumes and increased material costs, as discussed above. Cost of products sold also increased due to higher labor and overhead costs, partially offset by lower freight costs.
- Cost of products sold at T.O. Plastics increased $5.6 million primarily due to higher sales volumes, primarily in horticulture product sales, partially offset by favorable cost absorption.

PLASTICS SEGMENT RESULTS

The following table summarizes operating results for our Plastics segment for the years ended December 31, 2022 and 2021:

(in thousands)	*2022*	*2021*	*$ change*	*% change*
Operating Revenues	**$ 512,527**	$ 380,229	$ 132,298	34.8 %
Cost of Products Sold	**227,569**	228,789	(1,220)	(0.5)
Other Operating Expenses	**16,175**	14,326	1,849	12.9
Depreciation and Amortization	**4,205**	4,354	(149)	(3.4)
Operating Income	**$ 264,578**	$ 132,760	$ 131,818	99.3 %

Operating Revenues increased $132.3 million primarily due to a 66% increase in the price per pound of PVC pipe sold, as sales prices remained high and continued to increase in 2022, due to a continuation of extraordinary market conditions first experienced in the previous year. Sales volumes decreased 19% due to raw material constraints in the first half of 2022 and softening customer demand during the second half of 2022 driven by contractors delaying projects due to supply chain issues, softening housing market outlook, and customers reducing purchases of PVC pipe in order to use up existing on hand inventory.

Cost of Products Sold decreased $1.2 million primarily due to a 19% decrease in sales volumes, partially offset by a 22% increase in the cost per pound of PVC pipe sold, largely due to higher resin costs.

Other Operating Expenses increased $1.8 million due to increases in various cost categories including compensation costs and sales commissions.

CORPORATE COSTS

The following table summarizes Corporate results of operations for the years ended December 31, 2022 and 2021:

(in thousands)		**2022**		2021		$ change	% change
Other Operating Expenses	**$**	**16,202**	$	13,905	$	2,297	16.5 %
Depreciation and Amortization		**140**		225		(85)	(37.8)
Operating Loss	**$**	**16,342**	$	14,130	$	2,212	15.7 %

Other Operating Expenses increased $2.3 million primarily due to increased external service costs during the year, as well as increased employee compensation and other costs.

REGULATORY MATTERS

The following provides a summary of OTP's current general rates and a summary of recent rate case filings and rate rider filings that have or are expected to have a material impact on our operating results, financial position, or cash flows.

GENERAL RATES

The following includes a summary of electric base rates as determined in OTP's most recent general rate case in each state:

Jurisdiction	*Implementation Date*		*Revenue Requirement (in millions)*	*Return on Rate Base*	*Allowed Return on Equity*	*Equity Ratio*
Minnesota	07/01/22	$	209.0	7.18 %	9.48 %	52.50 %
North Dakota	02/01/19		153.1	7.64	9.77	52.50
South Dakota[(1)]	08/01/19		35.5	7.09	8.75	52.92

(1) Includes an earnings sharing mechanism to share with South Dakota customers any weather-normalized earnings above the authorized ROE of 8.75%. The mechanism requires 50% of any weather-normalized revenue creating annual earnings in excess of the authorized ROE up to a maximum of 9.50% be returned to customers and 100% returns of revenue creating annual earnings above 9.50%.

Minnesota Rate Case: On November 2, 2020, OTP filed an initial request with the MPUC for an increase in revenue recoverable through base rates in Minnesota, and on December 3, 2020, the MPUC approved an interim annual rate increase of $6.9 million, or 3.2%, effective January 1, 2021.

On February 1, 2022, the MPUC issued its written order on final rates. The key provisions of the order included a revenue requirement of $209.0 million, based on a return on rate base of 7.18% and an allowed ROE of 9.48% on an equity ratio of 52.5%. The order also authorized recovery of our remaining Hoot Lake Plant net asset over a five-year period and approved the requested decoupling mechanism for most residential and commercial customer rate groups with a cap of 4% of annual base revenues.

On May 12, 2022, OTP's final rate case compliance filing was approved by the MPUC. The filing included final revenue calculations, rate design, and resulting tariff revisions, along with a determination of the interim rate refund, which resulted in an increase in revenues in 2022 of $4.1 million. Final rates took effect on July 1, 2022, and interim rate refunds of $15.3 million were completed in the third quarter of 2022.

RATE RIDERS

The following table includes a summary of pending and recently concluded rate rider proceedings:

Recovery Mechanism	Jurisdiction	Status	Filing Date	Amount (in millions)	Effective Date	Notes
RRR - 2022	MN	Requested	11/01/22	$17.5	07/01/23	Includes the recovery of the Hoot Lake Solar Project, the purchase of the Ashtabula III wind farm, and true up PTCs in base rates to actual PTCs generated at the Merricourt wind farm.
CIP - 2022	MN	Approved	04/01/22	10.8	10/01/22	Includes recovery of energy conservation improvement costs as well as a demand side management financial incentive.
CIP - 2021	MN	Approved	04/01/21	9.4	12/01/21	Includes recovery of energy conservation improvement costs as well as a demand side management financial incentive.
TCR - 2021	MN	Approved	11/23/21	7.2	08/01/22	Includes recovery of two new transmission projects.
RRR - 2021	MN	Approved	12/06/21	7.0	08/01/22	Includes return on Hoot Lake Solar construction costs and costs associated with the acquisition of the Ashtabula III wind farm.
RRR - 2023	ND	Requested	12/30/22	17.0	04/01/23	Includes recovery of Ashtabula III investment, along with other proposals, see additional information below.
RRR - 2021	ND	Approved	03/07/21	11.8	04/01/21	Includes recovery of Merricourt investment and operating costs.
RRR - 2022	ND	Approved	01/05/22	7.8	04/01/22	Includes Merricourt recovery, the proposed purchase of Ashtabula III, and credits related to deferred taxes and PTCs.
TCR - 2022	ND	Approved	09/15/22	7.5	01/01/23	Includes recovery of three new transmission projects, one transmission rebuild project, and six transmission projects related to extending the useful life of transmission assets.
TCR - 2021	ND	Approved	09/15/21	6.1	01/01/22	Includes recovery of three new transmission projects/programs.
TCR - 2020	ND	Approved	08/31/20	5.6	01/01/21	Includes recovery of eight new transmission projects.
GCR - 2021	ND	Approved	03/01/21	5.2	07/01/21	Includes recovery of Astoria Station, net of anticipated savings associated with the retirement of Hoot Lake Plant.
GCR - 2022	ND	Approved	03/01/22	3.3	07/01/22	Annual update to generation cost recovery rider.
AMDT - 2022	ND	Approved	07/08/22	3.1	01/01/23	Includes recovery of the advanced metering infrastructure, outage management system, and demand response projects.
PIR - 2022	SD	Approved	06/01/22	3.0	09/01/22	Includes recovery of the Ashtabula III wind farm purchase, Merricourt, Astoria Station, and the Advanced Grid Infrastructure project, as well as load growth credits.
TCR - 2023	SD	Requested	11/01/22	3.0	03/01/23	Includes the recovery of one new and four previously approved transmission projects.
TCR - 2022	SD	Approved	10/29/21	2.2	03/01/22	Annual update to TCR rider.
TCR - 2021	SD	Approved	10/30/20	2.2	03/01/21	Includes recovery of two new transmission projects.

Renewable Resource Rider (RRR) and Energy Adjustment Rider (EAR): On December 30, 2022, OTP filed an update to its North Dakota RRR. The update included, among other items, a request to modify load allocation factors in North Dakota given the large new load added in the state in 2022. If approved, the load allocation factor change would produce an additional $4.4 million of rider recovery over a 12 month period. On January 23, 2023, OTP filed an update to its North Dakota EAR proposing to refund MISO planning resource auction revenues to North Dakota customers if the NDPSC approves the load allocation factor modification as filed in the RRR docket. If approved, OTP would refund approximately $4.2 million of planning resource auction revenues to North Dakota customers.

MISO PLANNING RESOURCE AUCTION

OTP offered 88-megawatts of excess capacity into the annual MISO planning resource auction for the period June 2022 through May 2023. As a result of a capacity shortage in the MISO region, capacity prices cleared the auction at maximum pricing. As a result, the 88-megawatts of auctioned capacity will generate approximately $9.3 million of net capacity auction revenues over the twelve month period ending in May 2023. We anticipate the Minnesota allocated portion of net capacity auction revenues will be returned to customers through the FCA mechanism in the state, and the majority of the net capacity auction revenues allocated to our other jurisdictions will be used to mitigate customer rate increases or returned to customers through various mechanisms.

INTEGRATED RESOURCE PLAN

The MPUC recently approved a change to the procedural schedule for our 2022 IRP, which was originally filed in September 2021, and we plan to file an updated IRP in March 2023. In conjunction with the updated IRP, our preferred plan could change based on the results of the updated resource modeling we perform, incorporating recent changes affecting the energy industry and the passing of the IRA, as well as other changes. A change to our preferred plan could ultimately impact the nature, timing and amount of future capital investments, as well as the potential for OTP's withdrawal from Coyote Station, and could have a material impact on our operating results, financial position or cash flows.

LIQUIDITY

LIQUIDITY OVERVIEW

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets, and borrowing ability because of investment-grade credit ratings, when taken together, provide us ample liquidity to conduct business operations and fund our capital expenditure program. Our liquidity, including our operating cash flows and access to capital markets, can be impacted by macroeconomic factors outside of our control. In addition, our liquidity could be impacted by non-compliance with covenants under our various debt instruments. As of December 31, 2022, we were in compliance with all debt covenants (see the Financial Covenant section under Capital Resources below).

The following table presents the status of our lines of credit as of December 31, 2022 and 2021:

(in thousands)	*Line Limit*	*2022 Amount Outstanding*	*2022 Letters of Credit*	*2022 Amount Available*	*2021 Amount Available*
Otter Tail Corporation Credit Agreement	$ 170,000	$ —	$ —	**$ 170,000**	$ 147,363
OTP Credit Agreement	170,000	8,204	9,573	**152,223**	88,315
Total	$ 340,000	$ 8,204	$ 9,573	**$ 322,223**	$ 235,678

We have an internal risk tolerance metric to maintain a minimum of $50 million of liquidity under the OTC Credit Agreement. Should additional liquidity be needed, this agreement includes an accordion feature allowing us to increase the amount available to $290 million, subject to certain terms and conditions. The OTP Credit Agreement also includes an accordion feature allowing OTP to increase that facility to $250 million, subject to certain terms and conditions.

CASH FLOWS

The following is a discussion of our cash flows for the years ended December 31, 2022 and 2021:

(in thousands)	*2022*	*2021*
Net Cash Provided by Operating Activities	**$ 389,309**	$ 231,243

Net Cash Provided by Operating Activities increased $158.1 million primarily due to a $107.4 million increase in net income and a lower level of working capital needs compared to the previous year. Our working capital decrease was primarily the result of a $30.6 million decrease in accounts receivable and a $5.3 million decrease in inventories, which exceeded the decrease in accounts payable and accrued and other liabilities. The decrease in accounts receivable was primarily due to decreased sales prices in our Manufacturing segment in the second half of the year, as steel prices declined from historically high levels in 2021, and decreased sales volumes in our Plastics segment in the second half of the year, as customer demand softened. The decrease in inventories was largely the result of decreased material costs within our Manufacturing segment, due to the decrease in steel prices. The decrease in accounts payable was largely due to the decreased material costs in our Manufacturing segment and decreased sales volumes in our Plastics segment in the second half of the year.

Unique market dynamics experienced by our Plastics segment businesses in 2022 and 2021 resulted in a significant increase in our overall cash from operations compared to prior periods, and we do not expect cash from operations at these levels to continue in future years.

(in thousands)	*2022*	*2021*
Net Cash Used in Investing Activities	**$ 175,071**	$ 171,510

Net Cash Used in Investment Activities increased $3.6 million due to a $7.8 million increase in capital investments in our Electric segment, combined with a decrease in proceeds received from the sale of debt and equity securities at our captive insurance entity, largely offset by a decrease in capital investments in our Manufacturing and Plastics segments.

(in thousands)	*2022*	*2021*
Net Cash Used in Financing Activities	**$ 96,779**	$ 59,359

Net Cash Used in Financing Activities increased $37.4 million primarily due to repayments of short-term borrowings, partially offset by increases in long-term debt. Our financing activities in 2022 included the issuance of $90.0 million of long-term debt and the maturity and repayment of $30.0 million of debt at OTP, net repayments of short-term borrowings of $83.0 million, which were repaid with available cash resulting from increased cash from operations, and dividend payments of $68.8 million. In 2021, $140.0 million of long-term debt was issued and used to repay $140.0 million of maturing long-term debt at OTP, we incurred $10.1 million of net short-term borrowings on our lines of credit, and paid $64.9 million in dividends.

CAPITAL REQUIREMENTS

CAPITAL EXPENDITURES

We have a capital expenditure program for expanding, upgrading and improving our facilities and operating equipment. Typical uses of cash for capital expenditures are investments in electric generation facilities and environmental upgrades, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, and computer hardware and information systems. Our capital expenditure program is subject to review and is revised in light of changes in demands for energy, technology, environmental laws, regulatory changes, business expansion opportunities, the costs of labor, materials and equipment and our financial condition.

The following provides a summary of capital expenditures for the years ended December 31, 2022 and 2021 for our Electric segment and non-electric businesses and anticipated capital expenditures for the five year period 2023 through 2027:

(in millions)	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*Total*
Electric Segment:								
Renewables and Natural Gas Generation			$ 88	$ 119	$ 88	$ 79	$ 10	$ 384
Technology and Infrastructure			33	30	6	5	1	75
Distribution Plant Replacements			33	37	38	38	43	189
Transmission (includes replacements)			34	36	46	87	78	281
Other			26	25	30	25	22	128
Total Electric Segment	$ 140	$ 148	$ 214	$ 247	$ 208	$ 234	$ 154	$ 1,057
Manufacturing and Plastics Segments	32	23	48	53	29	25	24	179
Total Capital Expenditures	**$ 172**	**$ 171**	**$ 262**	**$ 300**	**$ 237**	**$ 259**	**$ 178**	**$ 1,236**
Total Electric Utility Average Rate Base	**$ 1,575**	**$ 1,624**	**$ 1,750**	**$ 1,850**	**$ 1,990**	**$ 2,110**	**$ 2,210**	
Rate Base Growth	13.7 %	3.1 %	7.8 %	5.7 %	7.6 %	6.0 %	4.7 %	

CONTRACTUAL OBLIGATIONS

The following table summarizes our contractual obligations at December 31, 2022 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	*Total*	*Less than 1 Year*	*1-3 Years*	*3-5 Years*	*More than 5 Years*
Debt Obligations	**$ 835**	$ 8	$ —	$ 122	$ 705
Interest on Debt Obligations	**637**	35	70	67	465
Coal Contracts	**527**	24	49	52	402
Capacity and Energy Requirements	**5**	—	1	—	4
Postretirement Benefit Obligations	**86**	5	12	13	56
Other Purchase Obligations (including land easements)	**55**	14	4	4	33
Operating Lease Obligations	**21**	6	10	4	1
Total Contractual Cash Obligations	**$ 2,166**	$ 92	$ 146	$ 262	$ 1,666

Coal contract obligations are based on estimated coal consumption and costs for the delivery of coal to Coyote Station from Coyote Creek Mining Company (CCMC) under the LSA that ends in 2040. Postretirement benefit obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan (ESSRP), but do not include amounts to fund our noncontributory funded pension plan, as we are not currently required to make a contribution to that plan.

COMMON STOCK DIVIDENDS

We paid dividends to our shareholders totaling $68.8 million, or $1.65 per share, in 2022. The determination of the amount of future cash dividends to be paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by OTC subsidiaries. See Note 14 to our consolidated financial statements included in this report on Form 10-K for additional information. The decision to declare a dividend is reviewed quarterly by our Board of Directors. On February 3, 2023, our Board of Directors increased the quarterly dividend from $0.4125 to $0.4375 per common share.

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, borrowing capacity under our lines of credit, strong financial coverages, investment grade credit ratings and alternative financing arrangements such as leasing. Debt financing will be required in the five-year period from 2023 through 2027 to refinance maturing debt and to finance our capital investments within our Electric segment. Our financing plans are subject to change and are impacted by our planned level of capital investments, a decision to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes.

REGISTRATION STATEMENTS

On May 3, 2021, we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. The registration statement expires in May, 2024. No shares were issued pursuant to the registration statement in 2022.

On May 3, 2021, we filed a second registration statement with the SEC for the issuance of up to 1,500,000 common shares under an Automatic Dividend Reinvestment and Share Purchase Plan, which provides shareholders, retail customers of OTP and other interested investors a method of purchasing our common shares by reinvesting their dividends and/or making optional cash investments. Shares purchased under the plan may be new issue common shares or common shares purchased on the open market. The registration statement expires in May 2024. In 2022, we issued 133,827 shares under the plan. All shares issued under the plan to date have been open market purchases and there have been no new issue shares, resulting in no proceeds received by the Company. As of December 31, 2022, 1,250,993 shares remained available for purchase or issuance under the Plan.

SHORT-TERM DEBT

OTC and OTP are each party to a credit agreement (the OTC Credit Agreement and OTP Credit Agreement, respectively) which provides for unsecured revolving lines of credit. On October 31, 2022, the credit agreements were amended to extend the maturity date of each credit facility from September 30, 2026 to October 29, 2027, and to replace the London Interbank Offered Rate (LIBOR) as a benchmark interest rate. The agreements generally bear interest at the Secured Overnight Financing Rate (SOFR) plus an applicable credit spread, which is subject to adjustment based on the credit ratings of the issuer. The weighted-average interest rate on all outstanding borrowings as of December 31, 2022 and 2021 was 5.61% and 1.42%.

The following is a summary of key provisions and borrowing information as of and for the year ended December 31, 2022:

(in thousands, except interest rates)	*OTC Credit Agreement*	*OTP Credit Agreement*
Borrowing Limit	$ 170,000	$ 170,000
Borrowing Limit if Accordion Exercised[1]	290,000	250,000
Amount Restricted Due to Outstanding Letters of Credit at Year-End	—	9,573
Amount Outstanding at Year-End	—	8,204
Average Amount Outstanding During Year	11,686	22,698
Maximum Amount Outstanding During the Year	58,715	74,519
Interest Rate at Year-End	5.9 %	5.6 %
Expiration Date	October 29, 2027	October 29, 2027

[1]Each facility includes an accordion feature allowing the borrower to increase the borrowing limit if certain terms and conditions are met.

LONG-TERM DEBT

At December 31, 2022, we had $827.0 million of principal outstanding under long-term debt arrangements. Note 9 to our consolidated financial statements included in this report on Form 10-K includes information regarding these instruments. The agreements generally provide for unsecured borrowings at fixed rates of interest with maturities ranging from 2026 to 2052. One OTP debt instrument with a principal balance of $30.0 million matured in August 2022. Pursuant to a Note Purchase Agreement executed in June 2021, OTP issued its Series 2022A notes in May 2022, for aggregate proceeds of $90.0 million, and used a portion of the proceeds to repay the $30.0 million which matured in August 2022.

Financial Covenants

Certain of our short- and long-term debt agreements require OTC and OTP to maintain certain financial covenants. As of December 31, 2022, we were in compliance with these financial covenants as further described below:

OTC, under its financial covenants, may not permit its ratio of Interest-Bearing Debt to Total Capitalization to exceed 0.60 to 1.00, may not permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, and may not permit its Priority Indebtedness to exceed 10% of our Total Capitalization. As of December 31, 2022, our Interest-Bearing Debt to Total Capitalization was 0.41 to 1.00, our Interest and Dividend Coverage Ratio was 11.12 to 1.00 and we had no Priority Indebtedness outstanding.

OTP, under its financial covenants, may not permit its ratio of Debt to Total Capitalization to exceed 0.60 to 1.00, may not permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, and may not permit its Priority Debt to exceed 20% of its Total Capitalization. As of December 31, 2022, OTP's Interest-Bearing Debt to Total Capitalization was 0.45 to 1.00, its Interest and Dividend Coverage Ratio was 3.66 to 1.00 and it had no Priority Indebtedness outstanding.

None of our debt agreements include any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

Credit Ratings

The credit ratings of OTC and OTP as of December 31, 2022 are summarized below:

	Otter Tail Corporation			Otter Tail Power Company		
	Moody's	*Fitch*	*S&P*	*Moody's*	*Fitch*	*S&P*
Corporate Credit/Long-Term Issuer Default Rating	Baa2	BBB-	BBB	A3	BBB	BBB+
Senior Unsecured Debt	n/a	BBB-	n/a	n/a	BBB+	BBB+
Outlook	Stable	Stable	Stable	Stable	Stable	Stable

CRITICAL ACCOUNTING ESTIMATES

Preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and the Company's discussion and analysis of its financial condition and operating results requires management to make assumptions, estimates and judgments that affect the reported amounts. While we believe the estimates, assumptions, and judgments we use in preparing our consolidated financial statements are appropriate and are based on the best available information, they are subject to future events and uncertainties regarding their outcome and therefore actual results may materially differ from these estimates. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of our Board of Directors. The following critical accounting policies affect the most significant judgments and estimates used in the preparation of our consolidated financial statements.

REGULATORY ACCOUNTING

Our utility business is subject to regulation of rates and other matters by state utility commissions in Minnesota, North Dakota and South Dakota and by the FERC for certain interstate operations. Accordingly, our utility business must adhere to the accounting requirements of regulated operations, which requires the recognition of regulatory assets and regulatory liabilities for amounts that otherwise would impact the statement of income or comprehensive income when it is probable that such amounts will be collected from customers or credited to customers through the rate-making process. This guidance also provides recognition criteria for adjustments to rates outside of a general rate case proceeding which are provided to encourage or incentivize investments in certain areas such as conservation, renewable energy, pollution reduction or control, improved infrastructure of the transmission grid or other programs that provide benefits to the general public under public policy, laws or regulations. Regulatory assets generally represent costs that have been incurred but have been deferred because future recovery from customers, as established through the rate-making process, is probable. Regulatory liabilities generally represent amounts to be refunded to customers or amounts currently collected from customers for future costs.

We assess the probability of recovery of regulatory assets and the obligations arising from regulatory liabilities on a quarterly basis. Our probability estimates incorporate numerous factors, including recent rate making decisions, historical precedents for similar matters, the regulatory environments in which we operate and the impact these incurred costs may have on our customers. Changes in our assessments regarding the likelihood of recovery or settlement of our regulatory assets and liabilities may have a material impact on our operating results and financial position. Further, if we determine that all or a portion of our utility business no longer meets the criteria for continued application of regulatory accounting, or our regulators disallow recovery of a previously incurred cost or eliminate a regulatory liability, we would be required to remove the associated regulatory assets and liabilities from our consolidated balance sheet and recognize in the consolidated statement of income as an expense or income item in the period in which this accounting treatment is no longer applicable.

As of December 31, 2022 and 2021, we had regulatory assets of $119.7 million and $152.9 million and regulatory liabilities of $261.8 million and $259.3 million. If future recovery of amounts recorded as regulatory assets was no longer probable we would be required to recognize expense or other comprehensive loss in the period in which recovery was deemed to no longer be probable.

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. See Note 10 to our consolidated financial statements included in this report on Form 10-K for additional information on our pension and postretirement benefit plans and related assumptions.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 30 or more years. These benefits can be paid out for up to 40 or more years after an employee retires. Estimates of liabilities and expenses related to these benefits are among our most critical accounting estimates. Although deferral and amortization of fluctuations in actuarially determined benefit obligations and expenses are provided for when actual results on a year-to-year basis deviate from long-range assumptions, compensation increases and healthcare cost increases or a reduction in the discount rate applied from one year to the next can significantly increase our benefit expenses in the year of the change. Likewise, compensation decreases and healthcare cost decreases or an increase in the discount rate applied from one year to the next can significantly decrease our benefit expenses in the year of the change. Also, a change in the expected rate of return on pension plan assets in our funded pension plan or realized rates of return on plan assets that are well above or below assumed rates of return or a change in the anticipated life expectancy of plan participants could result in significant increases or decreases in recognized pension benefit expenses in the year of the change or for many years thereafter because actuarial losses can be amortized over the average remaining service lives of active employees.

We estimate the discount rate through the use of a hypothetical bond portfolio method, which incorporates yields on a collection of high credit quality bonds that produce cash flows similar to our anticipated future benefit payments.

We estimate the assumed long-term rate of return on plan assets based on asset category studies using historical market returns achieved by our asset portfolio allocation over long-term periods, as well as long-term projected return levels.

Pension plan assets are invested in a portfolio according to our return, liquidity and diversification objectives to provide a source of funding for plan obligations and manage contributions to the plan. The principal process for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

At December 31, 2022, we set the discount rate used to measure our pension plan obligations at 5.51% and at 5.52% to measure postretirement healthcare obligations, a 248 and 251 basis point increase, respectively, from the estimates used at December 31, 2021. Our estimates used to determine benefit cost for 2022 included a discount rate of 3.03% for pension benefits and 3.01% for postretirement healthcare costs, a 25 and 26 basis point decrease, respectively, from 2021 estimates. In addition, we estimated our assumed rate of return on pension assets to be 6.30% for 2022, a 21 basis point decrease from our 2021 estimate.

The following table summarizes the impact on 2022 pension and postretirement costs for a 25 basis point increase or decrease, holding all other variables constant, on certain key assumptions:

(in thousands)	*+0.25*	*-0.25*
Pension Plan:		
Discount Rate	$ (1,147)	$ 1,207
Rate of Increase in Future Compensation	801	(757)
Long-Term Return on Plan Assets	(940)	940
Other Postretirement Benefits:		
Discount Rate	(310)	326

For 2023, we expect pension benefit income for our pension plan to be $5.8 million compared to $3.1 million of pension benefit expense in 2022, due to an increase in the discount rate used to determine benefit costs and an increase in the expected return on plan assets, partially offset by an increase in expected future compensation costs. The estimated discount rate used to determine annual benefit cost accruals increased from 3.03% in 2022 to 5.51% in 2023. The assumed rate of return on pension plan assets is 7.00% for 2023, compared with the assumption of 6.30% in 2022.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates, increases or decreases in the discount rate, increases in future compensation levels, and increases in retiree healthcare cost inflation rates could significantly change projected costs.

We believe the estimates made for our pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are subject to change.

GOODWILL IMPAIRMENT

Goodwill is required to be evaluated annually for impairment and more frequently as events or circumstances require. Goodwill is tested for impairment at the reporting unit level. We have identified two reporting units which carry a material amount of goodwill.

The goodwill impairment test is a single-step quantitative assessment which compares the estimated fair value of the reporting unit to its carrying value. An impairment charge is recognized if the carrying amount exceeds the estimated fair value in an amount that is equal to the excess but limited to the amount of recorded goodwill of the reporting unit. An optional qualitative impairment assessment may be performed prior to and may eliminate the need to perform the quantitative assessment.

Estimating the fair value of a reporting unit under the quantitative impairment method requires significant judgments and estimates. We estimate the fair value of our reporting units primarily using an income approach, which includes a discounted cash flow methodology to arrive at a fair value estimate by determining the present value of projected future cash flows over a specified period plus a terminal value to reflect cash flows beyond the projection period. The discount rate applied to the estimated future cash flows reflects our estimate of the weighted-average cost of capital of comparable entities. To supplement our income approach, we reference various market indications of fair value, where available, and include fair value estimates using multiples derived from comparable enterprise values to EBITDA, comparable price earnings ratios and, if available, comparable sales transactions for comparative peer companies.

Our discounted cash flow methodology incorporates significant estimates, which include assumptions of future operating results and cash flows, which are impacted by economic and industry conditions, the amount and timing of estimated capital expenditures, an estimated terminal growth rate and the selection of an appropriate weighted-average cost of capital, among others.

Our goodwill impairment testing performed in the fourth quarter of 2022 indicated no impairment was present for either reporting unit and the estimated fair value of each reporting unit substantially exceeded the respective carrying value. As part of our testing we perform various sensitivity analyses to understand if our conclusions are sensitive to changes in certain assumptions. A 1% decrease in projected operating revenues, a one hundred basis point decrease in projected gross profit margins and a twenty five basis point increase in the discount rate would not lead to a goodwill impairment charge for either reporting unit.

We believe the estimates and assumptions used in our impairment assessments are reasonable and based on the best information available. However, these estimates and assumptions inherently include a degree of uncertainty. Significant adverse changes in our expectations for any of these estimates could result in an impairment charge in a future period which may materially impact our operating results and financial position.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the potential loss arising from adverse changes in market rates and prices. We are primarily exposed to interest rate and commodity price risk.

Commodity Price Risk
Our Electric segment business is exposed to market risk arising from changes in commodity prices for wholesale energy and natural gas. OTP purchases energy in the wholesale market to supplement its own electricity generation and to respond to changes in demand and variability in generating plant output. In addition, OTP procures natural gas as a fuel source for its combustion turbine peaking facilities. OTP's exposure to price risk for these commodities is largely mitigated by the current ratemaking process and regulatory framework, which generally allows recovery of purchased power and fuel costs from our electric customers.

OTP, where prudent, seeks to further manage its exposure to commodity price variability and reduce volatility in prices for its retail customers through the use of derivative instruments, primarily financial swap agreements. OTP does not engage in derivative and hedging activities for trading purposes. As of December 31, 2022, OTP was party to financial swap agreements with an aggregate notional amount of 295,000 megawatt-hours of electricity with various settlement dates throughout 2023. As of December 31, 2022, the aggregate fair value of these instruments was $7.1 million, reflected as a liability on our consolidated balance sheet. Holding other variables constant, a ten percent change in energy prices would have had an approximate $1.8 million impact on the fair value of these instruments.

Our Manufacturing segment businesses are exposed to market risk arising from changes in commodity prices for certain raw material inputs, including steel, aluminum, and polystyrene and other plastics resins. We attempt to manage commodity price risk by passing changes in the cost of these input materials through to our customers. If our efforts to manage commodity price risk are unsuccessful, the operating revenues and earnings of our Manufacturing segment could be impacted.

Our Plastics segment businesses are exposed to market risk arising from changes in prices for PVC resin, the primary raw material commodity used to manufacture PVC pipe. The PVC pipe industry as a whole is highly sensitive to volatility in PVC resin prices, with frequent adjustments to PVC pipe sale prices to reflect volatility in PVC resin costs. Historically, when resin prices are rising or stable, sales volumes have been higher. In contrast, when resin prices are falling, sales volumes have been lower. Due to the commodity nature of PVC resin and dynamic supply and demand factors worldwide, gross profit margins can fluctuate significantly from period to period.

We do not engage in any hedging activities within our Manufacturing and Plastics segments to manage our commodity price risk.

Interest Rate Risk
Our exposure to interest rate risk arises from outstanding short-term debt which is subject to variable rates of interest based on benchmark interest rates, primarily SOFR. As of December 31, 2022 and 2021, we had $8.2 million and $91.2 million of short-term debt outstanding. Holding other variables constant, a one percentage point change in interest rates would have had an approximate $0.3 million impact to interest charges in 2022 based on our average outstanding short-term debt during the year.

All of our outstanding long-term debt obligations as of December 31, 2022 and 2021 had fixed interest rates and were not subject to material interest rate risk. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, by limiting the amount of variable interest rate debt and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

We have not used hedging instruments to manage interest risk arising from our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

ITEM 8. FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Otter Tail Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Otter Tail Corporation and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2022, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding 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.

Rate and Regulatory Matters—Impact of Rate Regulation on the Financial Statements—Refer to Notes 1 and 5 to the financial statements.

Critical Audit Matter Description

The Company's regulated Electric segment accounts for the financial effects of regulation in accordance with ASC 980, Regulated Operations. This guidance allows for the recording of a regulatory asset or liability for certain costs or credits which otherwise would be recognized in the statement of income or comprehensive income based on an expectation that the cost will be recovered or returned in future rates. This guidance also provides for adjustments to rates outside of a general rate case proceeding to encourage or incentivize investments in certain areas such as conservation, renewable energy, pollution reduction or control, improved infrastructure of the transmission grid or other programs that provide benefits to the general public under public policy, laws or regulations.

The Company is subject to rate regulation by state and federal regulatory agencies (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric distribution companies in Minnesota, North Dakota and South Dakota. The Company assesses the probability of recovery of regulatory assets and the obligations arising from regulatory liabilities on a quarterly basis. Probability estimates incorporate numerous factors, including recent rate making decisions, historical precedents for similar matters, the regulatory environments in which the Company operates, and the impact that incurred costs may have on customers.

Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment, regulatory assets and liabilities, operating revenues and expenses, depreciation expense, income taxes and multiple disclosures in the notes to the financial statements. There is a risk that the Commissions will not approve full recovery of the costs of providing utility service or full recovery of all amounts invested in the utility business and a reasonable return on that investment. As a result, 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 capital expenditures or operating costs that management believes were prudently incurred, and (3) a refund 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 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 incurred as property, plant, and equipment and 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 initial recognition of amounts as property, plant, and equipment; 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 evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- We inquired of management about property, plant, and equipment that may be abandoned. We inspected the capital-projects budget and construction-in-process listings and inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.
- We compared actual spend for projects that have been capitalized to property, plant, and equipment to budget. We evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects.
- We obtained an analysis from management and letters from internal and external legal counsel, as appropriate, regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory 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 15, 2023

We have served as the Company's auditor since 1944.

OTTER TAIL CORPORATION
CONSOLIDATED BALANCE SHEETS

(in thousands, except share data)	*December 31,* 2022	2021
Assets		
Current Assets		
Cash and Cash Equivalents	**$ 118,996**	$ 1,537
Receivables, net of allowance for credit losses	**144,393**	174,953
Inventories	**145,952**	148,490
Regulatory Assets	**24,999**	27,342
Other Current Assets	**18,412**	17,032
Total Current Assets	**452,752**	369,354
Noncurrent Assets		
Investments	**54,845**	56,690
Property, Plant and Equipment, net of accumulated depreciation	**2,212,717**	2,124,605
Regulatory Assets	**94,655**	125,508
Intangible Assets, net of accumulated amortization	**7,943**	9,044
Goodwill	**37,572**	37,572
Other Noncurrent Assets	**41,177**	32,057
Total Noncurrent Assets	**2,448,909**	2,385,476
Total Assets	**$ 2,901,661**	$ 2,754,830
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-Term Debt	**$ 8,204**	$ 91,163
Current Maturities of Long-Term Debt	**—**	29,983
Accounts Payable	**104,400**	135,089
Accrued Salaries and Wages	**32,327**	31,704
Accrued Taxes	**19,340**	19,245
Regulatory Liabilities	**17,300**	24,844
Other Current Liabilities	**56,065**	55,671
Total Current Liabilities	**237,636**	387,699
Noncurrent Liabilities and Deferred Credits		
Pensions Benefit Liability	**33,210**	73,973
Other Postretirement Benefits Liability	**46,977**	66,481
Regulatory Liabilities	**244,497**	234,430
Deferred Income Taxes	**221,302**	188,268
Deferred Tax Credits	**15,916**	16,661
Other Noncurrent Liabilities	**60,985**	62,527
Total Noncurrent Liabilities and Deferred Credits	**622,887**	642,340
Commitments and Contingencies (Note 13)		
Capitalization		
Long-Term Debt, net of current maturities	**823,821**	734,014
Shareholders' Equity		
Common Stock: 50,000,000 shares authorized of $5 par value; 41,631,113 and 41,551,524 outstanding at December 31, 2022 and 2021	**208,156**	207,758
Additional Paid-In Capital	**423,034**	419,760
Retained Earnings	**585,212**	369,783
Accumulated Other Comprehensive Income (Loss)	**915**	(6,524)
Total Shareholders' Equity	**1,217,317**	990,777
Total Capitalization	**2,041,138**	1,724,791
Total Liabilities and Shareholders' Equity	**$ 2,901,661**	$ 2,754,830

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per-share amounts)	*Years Ended December 31,* 2022	2021	2020
Operating Revenues			
Electric	**$ 549,699**	$ 480,321	$ 446,088
Product Sales	**910,510**	716,523	444,019
Total Operating Revenues	**1,460,209**	1,196,844	890,107
Operating Expenses			
Electric Production Fuel	**65,110**	59,327	46,296
Electric Purchased Power	**100,281**	65,409	61,698
Electric Operating and Maintenance Expenses	**181,378**	159,669	150,848
Cost of Products Sold (excluding depreciation)	**542,944**	488,370	329,257
Other Nonelectric Expenses	**69,718**	65,394	55,051
Depreciation and Amortization	**92,597**	91,358	82,037
Electric Property Taxes	**17,742**	17,609	17,034
Total Operating Expenses	**1,069,770**	947,136	742,221
Operating Income	**390,439**	249,708	147,886
Other Income and Expense			
Interest Charges	**36,016**	37,771	34,447
Nonservice Cost Components of Postretirement Benefits	**(1,075)**	2,016	3,437
Other Income (Expense), net	**2,037**	2,900	6,055
Income Before Income Taxes	**357,535**	212,821	116,057
Income Tax Expense	**73,351**	36,052	20,206
Net Income	**$ 284,184**	$ 176,769	$ 95,851
Weighted-Average Common Shares Outstanding:			
Basic	**41,586**	41,491	40,710
Diluted	**41,931**	41,818	40,905
Earnings Per Share:			
Basic	**$ 6.83**	$ 4.26	$ 2.35
Diluted	**$ 6.78**	$ 4.23	$ 2.34

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
(in thousands)	*2022*	*2021*	*2020*
Net Income	**$ 284,184**	$ 176,769	$ 95,851
Other Comprehensive Income (Loss):			
Unrealized (Loss) Gain on Available-for-Sale Securities, net of tax benefit (expense) of $115, $52 and $(42)	**(432)**	(196)	155
Pension and Other Postretirement Benefit Plan, net of tax (expense) benefit of ($2,769), $(766) and $796	**7,871**	2,179	(2,225)
Total Other Comprehensive Income (Loss)	**7,439**	1,983	(2,070)
Total Comprehensive Income	**$ 291,623**	$ 178,752	$ 93,781

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in thousands, except common stock outstanding)	*Common Stock Outstanding*	*Par Value, Common Stock*	*Additional Paid-In Capital*	*Retained Earnings*	*Accumulated Other Comprehensive Income (Loss)*	*Total Shareholders' Equity*
Balance, December 31, 2019	**40,157,591**	**$ 200,788**	**$ 364,790**	**$ 222,341**	**$ (6,437)**	**$ 781,482**
Stock Issuances, Net of Expenses	868,484	4,342	32,466	—	—	36,808
Stock Issued Under Dividend Reinvestment and Stock Purchase Plans, Net of Expenses	365,267	1,826	13,221	—	—	15,047
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	78,537	393	(2,515)	—	—	(2,122)
Net Income	—	—	—	95,851	—	95,851
Other Comprehensive Loss	—	—	—	—	(2,070)	(2,070)
Stock Compensation Expense	—	—	6,284	—	—	6,284
Common Dividends ($1.48 per share)	—	—	—	(60,314)	—	(60,314)
Balance, December 31, 2020	**41,469,879**	**$ 207,349**	**$ 414,246**	**$ 257,878**	**$ (8,507)**	**$ 870,966**
Stock Issued Under Dividend Reinvestment and Stock Purchase Plans, Net of Expenses	11,540	58	446	—	—	504
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	70,105	351	(1,840)	—	—	(1,489)
Net Income	—	—	—	176,769	—	176,769
Other Comprehensive Income	—	—	—	—	1,983	1,983
Stock Compensation Expense	—	—	6,908	—	—	6,908
Common Dividends ($1.56 per share)	—	—	—	(64,864)	—	(64,864)
Balance, December 31, 2021	**41,551,524**	**$ 207,758**	**$ 419,760**	**$ 369,783**	**$ (6,524)**	**$ 990,777**
Employee Stock Purchase Plan Expenses	—	—	(219)	—	—	(219)
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	79,589	398	(3,321)	—	—	(2,923)
Net Income	—	—	—	284,184	—	284,184
Other Comprehensive Income	—	—	—	—	7,439	7,439
Stock Compensation Expense	—	—	6,814	—	—	6,814
Common Dividends ($1.65 per share)	—	—	—	(68,755)	—	(68,755)
Balance, December 31, 2022	**41,631,113**	**$ 208,156**	**$ 423,034**	**$ 585,212**	**$ 915**	**$ 1,217,317**

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)	*Years Ended December 31,* 2022	2021	2020
Operating Activities			
Net Income	**$ 284,184**	$ 176,769	$ 95,851
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	**92,597**	91,358	82,037
Deferred Tax Credits	**(745)**	(744)	(1,221)
Deferred Income Taxes	**32,424**	28,896	15,201
Discretionary Contribution to Pension Plan	**(20,000)**	(10,000)	(11,200)
Allowance for Equity Funds Used During Construction	**(1,690)**	(822)	(4,063)
Stock Compensation Expense	**6,814**	6,908	6,284
Other, net	**3,513**	(3,035)	222
Changes in Operating Assets and Liabilities:			
Receivables	**30,560**	(60,994)	(6,328)
Inventories	**5,339**	(54,313)	5,686
Regulatory Assets	**(2,464)**	(4,803)	(4,070)
Other Assets	**(368)**	(14,146)	(5,227)
Accounts Payable	**(29,763)**	38,734	3,832
Accrued and Other Liabilities	**(5,490)**	28,386	19,262
Regulatory Liabilities	**(6,846)**	1,948	7,204
Pension and Other Postretirement Benefits	**1,244**	7,101	8,451
Net Cash Provided by Operating Activities	**389,309**	231,243	211,921
Investing Activities			
Capital Expenditures	**(171,134)**	(171,829)	(371,553)
Proceeds from Disposal of Noncurrent Assets	**4,346**	9,702	5,011
Purchases of Investments and Other Assets	**(8,283)**	(9,383)	(9,110)
Net Cash Used in Investing Activities	**(175,071)**	(171,510)	(375,652)
Financing Activities			
Net Borrowings (Repayments) on Short-Term Debt	**(82,959)**	10,166	74,997
Proceeds from Issuance of Common Stock	—	696	52,432
Proceeds from Issuance of Long-Term Debt	**90,000**	140,000	75,000
Payments for Retirement of Long-Term Debt	**(30,000)**	(140,169)	(182)
Dividends Paid	**(68,755)**	(64,864)	(60,314)
Payments for Shares Withheld for Employee Tax Obligations	**(2,942)**	(1,507)	(2,069)
Other, net	**(2,123)**	(3,681)	3,831
Net Cash (Used in) Provided by Financing Activities	**(96,779)**	(59,359)	143,695
Net Change in Cash and Cash Equivalents	**117,459**	374	(20,036)
Cash and Cash Equivalents at Beginning of Period	**1,537**	1,163	21,199
Cash and Cash Equivalents at End of Period	**$ 118,996**	$ 1,537	$ 1,163
Supplemental Disclosures of Cash Flow Information			
Cash Paid During the Year for:			
Interest, net of amount capitalized	**$ 35,699**	$ 36,881	$ 33,199
Income Taxes	**$ 43,411**	$ 8,445	$ 5,177
Supplemental Disclosure of Noncash Investing Activities			
Accrued Property, Plant and Equipment Additions	**$ 12,420**	$ 12,081	$ 34,265

See accompanying notes to consolidated financial statements

1. Summary of Significant Accounting Policies

Overview

Otter Tail Corporation and its subsidiaries (collectively, the "Company", "us", "our" or "we") form a diverse, multi-platform business consisting of a vertically integrated, regulated utility with generation, transmission and distribution facilities complemented by manufacturing businesses providing metal fabrication for custom machine parts and metal components, manufacturing of extruded and thermoformed plastic products, and manufacturing of PVC pipe products. We classify our business into three segments: Electric, Manufacturing and Plastics. Note 2 includes an additional description of the segments and financial information regarding each segment.

Principles of Consolidation

These consolidated financial statements are presented in accordance with U.S. generally accepted accounting principles and include the accounts of OTC and its wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation except, as applicable, profits on sales to our regulated electric utility company from our nonregulated businesses, which is in accordance with the accounting requirements of regulated operations.

Use of Estimates

We use estimates based on the best information available in recording transactions and balances resulting from business operations. As better information becomes available, or actual amounts are known, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Regulatory Accounting

Our regulated electric utility company, Otter Tail Power Company, is subject to regulation of rates and other matters by state utility commissions in Minnesota, North Dakota and South Dakota and by the FERC for certain interstate operations. OTP accounts for the financial effects of regulation in accordance with accounting guidance for regulated operations. This guidance allows for the recording of a regulatory asset for certain costs which otherwise would be recognized in the statement of income or comprehensive income based on an expectation that the cost will be recovered in future rates. This guidance also requires the recording of a regulatory liability for certain credits which would otherwise be recognized in the statement of income or comprehensive income based on an expectation that the amount will be returned to customers in future rates. Amounts recorded as regulatory assets and regulatory liabilities are generally recognized in the statements of income at the time they are reflected in customer rates. In the event OTP ceases to meet the criteria to apply the guidance for regulated operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an expense or income item in the period in which the application of this guidance ceases.

Cash Equivalents

We consider all highly liquid investments purchased with maturity of 90 days or less to be cash equivalents.

Revenue from Contracts with Customers

Due to our diverse business operations, the recognition of revenue from contracts with customers depends on the product produced and sold or service performed. We recognize revenue from contracts with customers at prices that are fixed or determinable as evidenced by an agreement with the customer, when we have met our performance obligation under the contract and it is probable that we will collect the amount to which we are entitled in exchange for the goods or services transferred or to be transferred to the customer. Depending on the product produced and sold or service performed and the terms of the agreement with the customer, we recognize revenue either over time, in the case of delivery or transmission of electricity or related services or the production and storage of certain custom-made products, or at a point in time for the delivery of standardized products and other products made to customer specifications where the terms of the contract require transfer of the completed product. Provisions for sales returns, early payment terms discounts, and volume-based variable pricing incentives are recorded as reductions to revenue at the time revenue is recognized based on customer history, historical information and current trends. We include revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold. Sales or other taxes collected from customers are excluded from operating revenues.

Electric Segment Revenues. Most Electric segment revenues are earned from the generation, transmission and sale of electricity to retail customers at rates approved by state regulatory commissions. OTP also earns revenue from the transmission of electricity for others over the transmission assets it owns separately, or jointly with other transmission service providers, under rate tariffs established by the independent transmission system operator and approved by the FERC. A third source of revenue for OTP comes from the generation and sale of electricity to wholesale customers at contract or market rates. Revenues from all these sources meet the criteria to be classified as revenue from contracts with customers and are recognized over time as energy is delivered or transmitted. Revenue is recognized based on the metered quantity of electricity delivered or transmitted at the applicable rates. For electricity delivered and consumed after a meter is read but prior to the end of the reporting period, OTP records revenue and an unbilled receivable based on estimates of the kwh of energy delivered to the customer.

Manufacturing Segment Revenues. Our Manufacturing segment businesses earn revenue predominantly from the production and delivery of custom-made or standardized parts to customers across several industries and certain businesses also earn revenue from the production and sale of tools and dies to other manufacturers. For the production and delivery of standardized products and other products made to customer specifications where the terms of the contract require transfer of the completed product, we have met our performance obligation and recognize revenue at the point in time when the product is shipped. At this point we have no further obligation to provide services related to such products. The shipping terms used in these transactions are FOB shipping point.

Plastics Segment Revenues. Our Plastics segment businesses earn revenue predominantly from the sale and delivery of standardized PVC pipe products produced at their manufacturing facilities. Revenue from the sale of these products is recognized at the point in time when the product is shipped as there is no further obligation to provide services related to such products and the shipping terms are FOB shipping point. We have one customer within our Plastics segment for which we produce and store a product made to the customer's specifications and design under a build and hold agreement. For sales to this customer, we recognize revenue as the custom-made product is produced, adjusting the amount of revenue for volume rebate variable pricing considerations we expect the customer will earn and applicable early payment discounts we expect the customer will take. Ownership of the pipe transfers to the customer prior to delivery and we are paid a negotiated fee for storage of the pipe. Revenue for storage of the pipe is also recognized over time as the pipe is stored.

Alternative Revenue

In addition to recognizing revenue from contracts with customers, our Electric segment business also records revenue under alternative revenue program (ARP) requirements. Certain rate rider mechanisms qualify as ARP revenues as they provide for adjustments to rates outside of a general rate case proceeding to encourage or incentivize investments in certain areas such as conservation, renewable energy, pollution reduction or control, improved infrastructure of the transmission grid or other programs that provide benefits to the general public under public policy, laws or regulations. ARP riders generally provide for the recovery of specified costs and investments and include an incentive component to provide the regulated utility with a return on amounts invested.

We accrue ARP revenue on the basis of cost incurred, investments made and returns on those investments that qualify for recovery through established riders. ARP revenue is disclosed separately from revenue from contracts with customers and we have elected to report ARP revenue on a net basis, whereby amounts initially recorded as ARP revenue in a period are presented net of the reversal of amounts previously recognized as ARP revenue that are reclassified and recorded as revenue from contracts with customers when such amounts are included in the price of electricity to customers.

Receivables and Allowance for Credit Losses

We grant credit to our customers in the normal course of business with repayment terms generally ranging from 30 to 90 days after the invoice date. Late fees are assessed on certain receivables once they are 30 days past due. Unbilled receivables represent estimates of energy delivered to customers but not yet billed.

Receivables are stated at the billed or estimated unbilled amount less an allowance for estimated credit losses. An allowance for credit losses is established based on losses expected to occur over the contractual life of the receivable. We estimate an allowance for credit losses on our trade and unbilled receivables by evaluating historical aging and write-off history, adjusted for current and forecasted economic conditions, for groups of receivables that share similar economic characteristics. Other receivables are evaluated by reviewing individual accounts, considering aging, financial condition of the debtor, recent payment history and other relevant factors. Account balances are written-off in the period they are deemed to be uncollectible.

Inventories

Inventories are valued at the lower of cost or net realizable value. Costs for fuel, material and supply inventories of our Electric segment are determined on an average cost basis. Costs for raw material, work in process and finished goods inventories of our Manufacturing and Plastics segments are determined on a first-in first-out (FIFO) basis.

Inventories consist of the following as of December 31, 2022 and 2021:

(in thousands)	***2022***	***2021***
Finished Goods	**$ 43,812**	$ 39,903
Work in Process	**31,766**	35,705
Raw Material, Fuel and Supplies	**70,374**	72,882
Total Inventories	**$ 145,952**	$ 148,490

Investments

We invest in and hold, through a rabbi trust, corporate-owned life insurance policies to provide future funding for obligations under our supplemental pension plan and a non-qualified deferred compensation plan. The polices are recorded at cash surrender value and there are no restrictions on our ability to surrender the policies.

We hold debt, mutual fund investments and money market funds either as investments within our captive insurance entity or to provide future funding for obligations under non-qualified deferred compensation plans. These investments are recorded at fair value. Debt securities are deemed to be available-for-sale securities, accordingly unrealized gains and losses are generally excluded from earnings and recognized in accumulated other comprehensive income. We evaluate whether declines in fair value of debt securities below the cost basis are other-than-temporary. Declines in fair value deemed to be other-than-temporary result in the recognition of unrealized losses, or a portion thereof, in earnings. Unrealized gains and losses on mutual and money market funds are recognized in earnings immediately.

The following is a summary of our investments at December 31, 2022 and 2021:

(in thousands)		**2022**		2021
Corporate-Owned Life Insurance Policies	**$**	**38,991**	$	41,078
Corporate and Government Debt Securities		**8,761**		9,202
Mutual Funds		**5,503**		5,432
Money Market Funds		**1,560**		949
Other Investments		**30**		29
Total Investments	**$**	**54,845**	$	56,690

The amount of unrealized gains and losses on debt securities as of December 31, 2022 and 2021 is not material and no unrealized losses were deemed to be other-than-temporary. In addition, the amount of unrealized gains and losses on marketable equity securities still held as of December 31, 2022 and 2021 is not material.

Property, Plant and Equipment

Electric plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction (AFUDC). The amount of interest capitalized to electric plant was $0.9 million in 2022, $0.6 million in 2021 and $2.1 million in 2020. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Removal costs, when incurred, are charged against the regulatory liability. Maintenance, repairs and replacement of minor items are charged to operating expenses as incurred. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property, plant and equipment of nonelectric operations are carried at historical cost and are depreciated on a straight-line basis over the assets' estimated useful lives. The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. No interest was capitalized in 2022, 2021 or 2020. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

The estimated service lives for rate-regulated electric assets and nonelectric assets are included below:

	Service Life Range	
(years)	*Low*	*High*
Electric Assets:		
Production Plant	13	113
Transmission Plant	51	75
Distribution Plant	16	70
General Plant	5	60
Nonelectric Assets:		
Equipment	2	20
Buildings and Leasehold Improvements	2	40

Jointly-Owned Facilities

OTP is a joint owner in two coal-fired steam-powered electric generation plants: Big Stone Plant near Big Stone City, South Dakota and Coyote Station near Beulah, North Dakota. OTP is also a joint owner, with other regional utilities, in five major transmission lines. OTP's interest in each jointly-owned facility is reflected in the consolidated balance sheets on a pro-rata basis and OTP's share of direct revenue and expenses are included in operating revenues and expenses in the consolidated statements of income. Each participant in the jointly-owned facilities finances their own investments.

Goodwill and Other Intangible Assets

Goodwill is recognized and initially measured as any excess of the acquisition-date consideration transferred in a business combination over amounts recognized for the net identifiable assets acquired. Goodwill is not amortized but is tested for impairment annually, or more frequently if an event occurs or circumstances change that would more likely than not result in an impairment of goodwill. Impairment testing is performed at the reporting unit level, which is defined as an operating segment or one level below an operating segment. We perform our impairment testing in the fourth quarter of each year and have identified three reporting units that carry a goodwill balance.

Our impairment testing includes both an optional qualitative assessment and the quantitative impairment assessment. Our qualitative assessment includes an analysis of relevant events and circumstances to determine if it is more likely than not that the fair value of the reporting unit exceeds its book value. If, after this assessment, we determine that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, no additional analysis is necessary. In contrast, if after the assessment we determine it is more likely than not that the fair value of a reporting unit is less than its carrying amount, or if we elect to skip the optional qualitative assessment, the quantitative impairment assessment is performed. The quantitative assessment is a single-step test that identifies both the existence of impairment and the amount of impairment loss by comparing the estimated fair value of a reporting unit to its carrying value, with any excess carrying value over the fair value being recognized as an impairment loss.

Intangible assets with finite lives, which primarily consist of customer relationships, are carried at estimated fair value at the time of acquisition less accumulated amortization. The costs of the intangible assets are amortized over their estimated useful lives, which generally range from 15 to 20 years.

Leases
We recognize right-of-use lease assets and a corresponding lease liability at the lease commencement date. The length of our lease agreements varies from less than one year to approximately ten years. We have elected to not record lease assets and liabilities for leases with a lease term at commencement of 12 months or less; such leases are expensed on a straight-line basis over the lease term. If a lease contains an option to extend the lease term and there is reasonable certainty the option will be exercised, the option is considered in the lease term at inception. We have elected to not separate non-lease components (e.g., common area maintenance) from lease components on real estate leases, accordingly the recognized lease asset and lease liability incorporate in their measurement payments for non-lease components. Certain leases include variable lease payments as the amounts are subject to change over the lease term. We are unable to determine the interest rate implicit in our leases thus we apply our incremental borrowing rate to capitalize the right-of-use asset and lease liability. We estimate our incremental borrowing rate by incorporating considerations of lease term and lessee entity.

Recoverability of Long-Lived Assets
We review our long-lived assets including, among other assets, property, plant and equipment, amortizing intangible assets and right-of-use lease assets, whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. We determine potential impairment by comparing the carrying amount of the assets with the net cash flows expected to be provided by operating activities of the business or related assets. If the sum of the expected future net cash flows is less than the carrying amount of the assets, an impairment loss would be recognized. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset.

Asset Retirement Obligations
Legal obligations related to the future retirement of long-lived assets are recognized as asset retirement obligations (ARO). An ARO is recognized in the period in which the legal obligation is incurred and the amount of the obligation can be reasonably estimated, with an offsetting increase to the associated long-lived asset. AROs are initially recognized at fair value and increased with the passage of time (accretion). ARO estimates are revised periodically with any adjustment reflected in the ARO and associated long-lived asset.

Income Taxes
We use the asset and liability method to account for income taxes. Under this method, deferred tax assets and liabilities are recognized for the expected future tax consequences of all temporary differences between the carrying amounts of assets and liabilities and their respective tax bases. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. Deferred tax assets are reduced by a valuation allowance when it is more likely than not that a portion or all of the deferred tax assets will not be realized. The realizability of deferred tax assets is determined by taking into consideration forecasts of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies. Changes in valuation allowances are included in the provision for income taxes in the period of the changes.

We recognize the tax effects of all tax positions that are more-likely-than-not to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. Changes in the recognition or measurement of such positions are recognized in the provision for income taxes in the period of the changes. We classify interest and penalties on tax uncertainties as components of the provision for income taxes.

We apply the deferral method of accounting for ITCs and state wind energy credits. Under this method, ITCs and state wind energy credits are amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

Stock-Based Compensation
Stock-based compensation awards are measured at the grant-date fair value of the award and compensation expense is recognized on a straight-line basis over the applicable service or performance period. The service period may be limited to the period until such time that a recipient is retirement eligible as determined under the award agreement. Awards granted to employees eligible for retirement on the date of grant are expensed in the period of grant. We recognize the effects of award forfeitures as they occur.

Fair Value Measurements
Fair value is defined as the price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants. Three levels of inputs may be used to measure fair value:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

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 with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

In instances where the determination of the fair value measurement is based on inputs from different levels within the hierarchy, the level in the hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety.

Variable Interest Entity
In October 2012, the Coyote Station owners, including OTP, entered into an LSA with Coyote Creek Mining Company, L.L.C. , a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed upon profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are required to buy certain assets of CCMC at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC because the Coyote Station owners are required to buy the membership interests of CCMC at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE and the Company is not required to include CCMC in its consolidated financial statements.

If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC, the owners will satisfy or, if permitted by CCMC's applicable lenders, assume all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. In the event the contract is terminated prior to the end of the term due to certain events, OTP's maximum loss exposure, as a result of its involvement with CCMC, could be as high as $45 million, or OTP's 35% share of CCMC's unrecovered costs as of December 31, 2022, if recovery of such a loss is denied by regulatory authorities.

2. Segment Information

We classify our business into three segments, Electric, Manufacturing and Plastics, consistent with our business strategy, organizational structure and our internal reporting and review processes used by our chief operating decision maker to make decisions regarding allocation of resources, to assess operating performance and to make strategic decisions.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is a participant in the MISO markets. OTP's operations have been our primary business since 1907.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the western half of the United States and Canada.

Certain assets and costs are not allocated to our operating segments. Corporate operating costs include items such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment, rather it is added to operating segment totals to reconcile to consolidated amounts.

Information for each segment and our unallocated corporate costs for the years ended December 31, 2022, 2021 and 2020 are as follows:

(in thousands)	*2022*	*2021*	*2020*
Operating Revenue			
Electric	**$ 549,699**	$ 480,321	$ 446,088
Manufacturing	**397,983**	336,294	238,770
Plastics	**512,527**	380,229	205,249
Total	**1,460,209**	1,196,844	890,107
Depreciation and Amortization			
Electric	**72,050**	71,343	63,171
Manufacturing	**16,202**	15,436	14,933
Plastics	**4,205**	4,354	3,604
Corporate	**140**	225	329
Total	**92,597**	91,358	82,037
Operating Income (Loss)			
Electric	**113,138**	106,964	107,083
Manufacturing	**29,065**	24,114	16,103
Plastics	**264,578**	132,760	37,823
Corporate	**(16,342)**	(14,130)	(13,123)
Total	**390,439**	249,708	147,886
Interest Charges			
Electric	**31,950**	33,043	29,848
Manufacturing	**2,796**	2,239	2,215
Plastics	**585**	587	644
Corporate	**685**	1,902	1,740
Total	**36,016**	37,771	34,447
Income Tax Expense (Benefit)			
Electric	**5,065**	1,663	12,480
Manufacturing	**5,321**	4,704	2,939
Plastics	**68,688**	34,374	9,718
Corporate	**(5,723)**	(4,689)	(4,931)
Total	**73,351**	36,052	20,206
Net Income (Loss)			
Electric	**79,974**	72,458	66,778
Manufacturing	**20,950**	17,186	11,048
Plastics	**195,374**	97,823	27,582
Corporate	**(12,114)**	(10,698)	(9,557)
Total	**284,184**	176,769	95,851
Capital Expenditures			
Electric	**147,869**	140,031	356,581
Manufacturing	**17,954**	20,690	10,587
Plastics	**5,245**	11,040	4,322
Corporate	**66**	68	63
Total	**$ 171,134**	$ 171,829	$ 371,553

The following provides the identifiable assets by segment and corporate assets as of December 31, 2022 and 2021:

(in thousands)	*2022*	*2021*
Identifiable Assets		
Electric	**$ 2,351,961**	$ 2,283,776
Manufacturing	**245,869**	251,044
Plastics	**126,318**	162,565
Corporate	**177,513**	57,445
Total	**$ 2,901,661**	$ 2,754,830

Concentrations
Our Plastics segment businesses use PVC resin as a critical component within their PVC pipe manufacturing process. There are a limited number of PVC resin suppliers in the U.S., and in 2022, we sourced all of our PVC resin needs from two vendors. Although there are a limited number of PVC resin suppliers, we believe that other suppliers could provide PVC resin on comparable terms. Additionally, most U.S. resin production plants are located in the Gulf Coast region. These plants are subject to the risk of damage and production shutdowns because of exposure to hurricanes or other extreme weather events that occur in this region. The loss of a key vendor, or any interruption or delay in the supply of PVC resin could cause production delays, a possible loss of sales, or result in increased costs to secure resin, all of which would adversely affect our operating results.

Entity-Wide Information
No single customer accounted for over 10% of our consolidated operating revenues for the years ended December 31, 2022, 2021 and 2020. All of our long-lived assets are located within the United States and substantially all of our operating revenues are from customers located within the United States.

3. Revenue

We present our operating revenues from external customers, in total and by amounts arising from contracts with customers and ARP arrangements, disaggregated by revenue source and segment for the years ended December 31, 2022, 2021 and 2020:

(in thousands)	*2022*	*2021*	*2020*
Operating Revenues			
Electric Segment			
Retail: Residential	**$ 143,888**	$ 135,361	$ 127,260
Retail: Commercial and Industrial	**318,494**	262,408	254,951
Retail: Other	**7,918**	7,715	7,311
Total Retail	**470,300**	405,484	389,522
Transmission	**52,213**	48,835	44,001
Wholesale	**18,539**	17,936	4,857
Other	**8,647**	8,066	7,708
Total Electric Segment	**549,699**	480,321	446,088
Manufacturing Segment			
Metal Parts and Tooling	**338,865**	283,527	199,463
Plastic Products and Tooling	**49,080**	40,231	34,055
Scrap Metal	**10,038**	12,536	5,252
Total Manufacturing Segment	**397,983**	336,294	238,770
Plastics Segment			
PVC Pipe	**512,527**	380,229	205,249
Total Operating Revenue	**1,460,209**	1,196,844	890,107
Less: Noncontract Revenues Included Above		—	—
Electric Segment - ARP Revenues	**(9,266)**	(791)	6,936
Total Operating Revenues from Contracts with Customers	**$ 1,469,475**	$ 1,197,635	$ 883,171

4. Receivables

Receivables as of December 31, 2022 and 2021 are as follows:

(in thousands)	*2022*	*2021*
Receivables		
Trade	**$ 112,126**	$ 142,297
Other	**9,983**	10,591
Unbilled Receivables	**23,932**	23,901
Total Receivables	**146,041**	176,789
Less Allowance for Credit Losses	**1,648**	1,836
Receivables, net of allowance for credit losses	**$ 144,393**	$ 174,953

The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2022 and 2021:

(in thousands)		*2022*		*2021*
Beginning Balance	**$**	**1,836**	$	3,215
Additions Charged to Expense		**909**		93
Reductions for Amounts Written-Off, Net of Recoveries		**(1,097)**		(1,472)
Ending Balance	**$**	**1,648**	$	1,836

5. Regulatory Matters

Regulatory Assets and Liabilities

The following presents our current and long-term regulatory assets and liabilities as of December 31, 2022 and 2021 and the period we expect to recover or refund such amounts:

(in thousands)	*Period of Recovery/Refund*	*2022 Current*	*2022 Long-Term*	*2021 Current*	*2021 Long-Term*
Regulatory Assets					
Pension and Other Postretirement Benefit Plans[1]	See below	**$ —**	**$ 88,354**	$ 7,791	$ 114,961
Alternative Revenue Program Riders[2]	Up to 2 years	**5,679**	**2,508**	11,889	5,564
Asset Retirement Obligations[1]	Asset lives	**—**	**1,467**	—	742
ISO Cost Recovery Trackers[1]	Up to 2 years	**575**	**314**	—	1,342
Unrecovered Project Costs[1]	Up to 5 years	**320**	**990**	2,136	1,455
Deferred Rate Case Expenses[1]	Up to 2 years	**377**	**754**	607	1,131
Debt Reacquisition Premiums[1]	Up to 10 years	**25**	**216**	100	240
Fuel Clause Adjustments[1]	Up to 1 year	**10,893**	**—**	4,819	—
Derivative Instruments[1]	Up to 1 year	**7,130**	**—**	—	—
Other[1]	Various	**—**	**52**	—	73
Total Regulatory Assets		**24,999**	**94,655**	27,342	125,508
Regulatory Liabilities					
Deferred Income Taxes	Asset lives	**—**	**131,480**	—	129,437
Plant Removal Obligations	Asset lives	**8,509**	**105,733**	8,306	101,595
Fuel Clause Adjustments	Up to 1 year	**365**	**—**	1,554	—
Alternative Revenue Program Riders	Various	**2,504**	**7,136**	5,772	3,336
Pension and Other Postretirement Benefit Plans	Up to 1 year	**5,589**	**—**	2,603	—
Derivative Instruments	Up to 1 year	**—**	**—**	6,214	—
Other	Various	**333**	**148**	395	62
Total Regulatory Liabilities		**$ 17,300**	**$ 244,497**	$ 24,844	$ 234,430

[1]Costs subject to recovery without a rate of return.

[2]Amount eligible for recovery includes an incentive or rate of return.

Pension and Other Postretirement Benefit Plans represent benefit costs and actuarial losses and gains subject to recovery or refund through rates as they are expensed or amortized. These unrecognized benefit costs and actuarial losses and gains are eligible for treatment as regulatory assets or liabilities based on their probable inclusion in future electric rates.

Alternative Revenue Program Riders regulatory assets and liabilities are revenues not yet collected from customers or amounts subject to refund, respectively, primarily due to investments in qualifying transmission, conservation, renewable resource, environmental and other generation assets, and the impact of decoupling.

Asset Retirement Obligations represent the difference in timing of recognition of expense arising from these obligations and the amount recovered from customers.

Independent System Operator (ISO) Cost Recovery Trackers represent costs incurred to serve Minnesota customers for the under-collection of revenue based on expected versus actual construction costs on eligible projects.

Unrecovered Project Costs reflect costs incurred for abandoned generation and transmission assets and accelerated depreciation expense on a retired generation asset being recovered from customers.

Deferred Rate Case Expenses relate to costs incurred in conjunction with recent rate cases that are currently being recovered, or are expected to be recovered, from customers.

Debt Reacquisition Premiums represent costs to retire debt which are being recovered from customers over the remaining original lives of the reacquired debt.

Fuel Clause Adjustments represent the under- or over-collection of fuel costs to be collected from or returned to customers.

Deferred Income Taxes represent the revaluation of accumulated deferred income taxes arising from the change in the federal income tax rate in 2017. This amount is being refunded to customers over the estimated lives of the property assets from which the deferred income taxes originated.

Plant Removal Obligations represent amounts collected from customers to be used to cover actual removal costs as incurred.

Derivative Instruments represent unrealized gains and losses recognized on derivative instruments. On final settlement of such instruments, any realized gains or losses are paid to or recovered from customers.

Minnesota Rate Case

On November 2, 2020, OTP filed an initial request with the MPUC for an increase in revenue recoverable through base rates in Minnesota, and on December 3, 2020, the MPUC approved an interim annual rate increase of $6.9 million, or 3.2%, effective January 1, 2021.

On February 1, 2022, the MPUC issued its written order on final rates. The key provisions of the order included a revenue requirement of $209.0 million, based on a return on rate base of 7.18% and an allowed ROE of 9.48% on an equity ratio of 52.5%. The order also authorized recovery of our remaining Hoot Lake Plant net asset over a five-year period and approved the requested decoupling mechanism for most residential and commercial customer rate groups with a cap of 4% of annual base revenues.

On May 12, 2022, OTP's final rate case compliance filing was approved by the MPUC. The filing included final revenue calculations, rate design and resulting tariff revisions, along with a determination of the interim rate refund, which resulted in an increase in revenues during 2022 of $4.1 million. Final rates took effect on July 1, 2022, and interim rate refunds of $15.3 million were applied to customer accounts.

MISO Resource Planning Auction

In 2022, we offered excess capacity into the annual MISO planning resource auction for the period June 2022 through May 2023. As a result of a capacity shortage in the MISO region, capacity prices cleared the auction at maximum pricing. During the year ended December 31, 2022, OTP recorded approximately $5.3 million of excess capacity auction revenues. We anticipate the Minnesota allocated portion of net capacity auction revenues will be returned to customers through the FCA mechanism in the state, and a portion of the net capacity auction revenues allocated to our other jurisdictions will be used to mitigate customer rate increases or returned to customers through various mechanisms. At December 31, 2022, we recognized a reduction of a regulatory asset of $2.6 million and a refund liability of $1.8 million for net capacity auction revenues we anticipate will be refunded to customers.

6. Property, Plant and Equipment

Major classes of property, plant and equipment as of December 31, 2022 and 2021 include:

(in thousands)	*2022*	*2021*
Electric Plant in Service		
Production	**$ 1,343,097**	$ 1,332,067
Transmission	**756,848**	722,739
Distribution	**612,716**	574,488
General	**131,718**	129,151
Electric Plant in Service	**2,844,379**	2,758,445
Construction Work in Progress	**113,932**	74,926
Total Gross Electric Plant	**2,958,311**	2,833,371
Less Accumulated Depreciation and Amortization	**859,988**	817,302
Net Electric Plant	**2,098,323**	2,016,069
Nonelectric Property, Plant and Equipment		
Equipment	**218,770**	203,390
Buildings and Leasehold Improvements	**61,506**	56,908
Land	**13,652**	13,652
Nonelectric Property, Plant and Equipment	**293,928**	273,950
Construction Work in Progress	**15,170**	16,611
Total Gross Nonelectric Property, Plant and Equipment	**309,098**	290,561
Less Accumulated Depreciation and Amortization	**194,704**	182,025
Net Nonelectric Property, Plant and Equipment	**114,394**	108,536
Net Property, Plant and Equipment	**$ 2,212,717**	$ 2,124,605

Depreciation expense for the years ended December 31, 2022, 2021 and 2020 totaled $84.4 million, $85.8 million and $78.6 million.

The following table provides OTP's ownership percentages and amounts included in the December 31, 2022 and 2021 consolidated balance sheets for OTP's share of each of these jointly-owned facilities:

(dollars in thousands)	*Ownership Percentage*	*Electric Plant in Service*	*Construction Work in Progress*	*Accumulated Depreciation*	*Net Plant*
December 31, 2022					
Big Stone Plant	53.9 %	$ 338,411	$ 557	$ (118,044)	**$ 220,924**
Coyote Station	35.0 %	183,461	2,315	(111,666)	**74,110**
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(5,587)	**100,598**
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(10,095)	**68,089**
Big Stone South–Brookings 345 kV line	50.0 %	53,041	—	(4,406)	**48,635**
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,291	—	(3,211)	**23,080**
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,318)	**13,013**
December 31, 2021					
Big Stone Plant	53.9 %	$ 338,699	$ 260	$ (110,604)	$ 228,355
Coyote Station	35.0 %	182,610	1,110	(107,894)	75,826
Big Stone South–Ellendale 345 kV line	50.0 %	106,194	—	(4,052)	102,142
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(9,069)	69,115
Big Stone South–Brookings 345 kV line	50.0 %	52,975	—	(3,613)	49,362
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,291	—	(2,843)	23,448
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(2,995)	13,336

7. Intangible Assets

The following table summarizes our goodwill by segment as of December 31, 2022 and 2021:

(in thousands)	***2022***	***2021***
Manufacturing	**$ 18,270**	$ 18,270
Plastics	**19,302**	19,302
Total Goodwill	**$ 37,572**	$ 37,572

Our annual goodwill impairment testing, performed in the fourth quarters of 2022 and 2021, indicated no impairment existed as of the test date.

The following table summarizes the components of our intangible assets at December 31, 2022 and 2021:

(in thousands)	*Gross Amount*	*Accumulated Amortization*	*Net Carrying Amount*
December 31, 2022			
Customer Relationships	**$ 22,491**	**$ 14,568**	**$ 7,923**
Other	**26**	**6**	**20**
Total	**22,517**	**14,574**	**7,943**
December 31, 2021			
Customer Relationships	22,491	13,469	9,022
Other	26	4	22
Total	$ 22,517	$ 13,473	$ 9,044

Amortization expense for these intangible assets for each of the years ended December 31, 2022, 2021 and 2020 totaled $1.1 million.

Annual amortization expense for these intangible assets for the next five years is:

(in thousands)	***2023***	***2024***	***2025***	***2026***	***2027***
Amortization Expense	$ 1,100	$ 1,100	$ 1,100	$ 1,092	$ 1,090

8. Leases

We lease rail cars, warehouse and office space, land and certain office, manufacturing and material handling equipment under varying terms and conditions. All leases are classified as operating leases.

The components of lease cost and lease cash flows for the years ended December 31, 2022 and 2021 are as follows:

(in thousands)	**2022**	**2021**
Lease Cost		
Operating Lease Cost	**$ 5,606**	$ 5,298
Variable Lease Cost	**1,386**	1,020
Short-Term Lease Cost	**1,517**	1,465
Total Lease Cost	**8,509**	7,783
Lease Cash Flows		
Operating Cash Flows from Operating Leases	**$ 5,592**	$ 5,642

A summary of operating lease right-of-use lease assets and lease liabilities as of December 31, 2022 and 2021 is as follows:

(in thousands)	**2022**	**2021**
Right of Use Lease Assets[1]	**$ 18,610**	$ 19,133
Lease Liabilities		
Current[2]	**5,071**	4,168
Long-Term[3]	**13,876**	15,309
Total Lease Liabilities	**$ 18,947**	**$ 19,477**

[1]Included in Other Noncurrent Assets in the consolidated balance sheets.

[2]Included in Other Current Liabilities in the consolidated balance sheets.

[3]Included in Other Noncurrent Liabilities in the consolidated balance sheets.

Operating lease assets obtained in exchange for new operating liabilities amounted to $3.7 million and $2.1 million for the years ended December 31, 2022 and 2021.

Maturities of lease liabilities as of December 31, 2022 for each of the next five years and in the aggregate thereafter are as follows:

(in thousands)	***Operating Leases***
2023	**$ 5,802**
2024	**5,263**
2025	**4,355**
2026	**2,544**
2027	**1,722**
Thereafter	**1,163**
Total Lease Payments	**20,849**
Less: Interest	**1,902**
Present Value of Lease Liabilities	**$ 18,947**

The weighted-average remaining lease term and the weighted-average discount rate as of December 31, 2022 and 2021 are as follows:

	2022	**2021**
Weighted-Average Remaining Lease Term (in years)	**4.2**	4.9
Weighted-Average Discount Rate	**4.73 %**	5.09 %

9. Short-Term and Long-Term Borrowings

The following is a summary of our outstanding short- and long-term borrowings by borrower, OTC or OTP, as of December 31, 2022 and 2021:

	2022			2021		
(in thousands)	*OTC*	*OTP*	*Total*	*OTC*	*OTP*	*Total*
Short-Term Debt	**$ —**	**$ 8,204**	**$ 8,204**	$ 22,637	$ 68,526	$ 91,163
Current Maturities of Long-Term Debt	**—**	**—**	**—**	—	29,983	29,983
Long-Term Debt, net of current maturities	**79,798**	**744,023**	**823,821**	79,746	654,268	734,014
Total	**$ 79,798**	**$ 752,227**	**$ 832,025**	$ 102,383	$ 752,777	$ 855,160

Short-Term Debt

The following is a summary of our lines of credit as of December 31, 2022 and 2021:

		2022			2021
(in thousands)	*Line Limit*	*Amount Outstanding*	*Letters of Credit*	*Amount Available*	*Amount Available*
OTC Credit Agreement	$ 170,000	$ —	$ —	**$ 170,000**	$ 147,363
OTP Credit Agreement	170,000	8,204	9,573	**152,223**	88,315
Total	$ 340,000	$ 8,204	$ 9,573	**$ 322,223**	$ 235,678

On October 31, 2022, OTC entered into a Fifth Amended and Restated Credit Agreement and OTP entered into a Fourth Amended and Restated Credit Agreement, in each case amending and restating the previously existing credit agreements to extend the maturity date of each credit facility from September 30, 2026 to October 29, 2027, and to replace LIBOR as a benchmark interest rate with SOFR. The adoption of SOFR as a benchmark interest rate is in advance of the scheduled elimination of LIBOR as a benchmark interest rate on June 30, 2023. No other significant terms or conditions, including borrowing capacity, credit spreads or financial covenants, were modified under these amendments and restatements. The agreements both provide for $170.0 million unsecured revolving lines of credit to support operations, fund capital expenditures, refinance certain indebtedness and provide for the issuance of letters of credit in an aggregate amount not to exceed $40.0 million under the OTC Credit Agreement and $50.0 million under the OTP Credit Agreement. Each credit facility includes an accordion provision allowing the borrower to increase the borrowing capacity under the facility, subject to certain conditions, up to $290.0 million and $250.0 million under the OTC Credit Agreement and OTP Credit Agreement, respectively.

Borrowings under each credit facility are subject to a variable rate of interest on outstanding balances and a commitment fee is charged based on the average unused amount available to be drawn under the respective facility. The variable rate of interest to be charged is based on a benchmark interest rate, either SOFR or a Base Rate, as defined in the credit agreements, selected by the borrower at the time of an advance, subject to the conditions of each agreement, plus an applicable credit spread. The credit spread ranges from zero to 2.00%, depending on the benchmark interest rate selected and is subject to adjustment based on the credit ratings of the relevant borrower. The weighted-average interest rate on all outstanding borrowings as of December 31, 2022 and 2021 was 5.61% and 1.42%.

Each credit facility contains a number of restrictions on the borrower, including restrictions on the ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The agreements also require the borrower to maintain various financial covenants, as further described below.

Long-Term Debt

The following is a summary of outstanding long-term debt by borrower as of December 31, 2022 and 2021:

				(in thousands)	
Entity	*Debt Instrument*	*Rate*	*Maturity*	*2022*	*2021*
OTC	Guaranteed Senior Notes	3.55%	12/15/26	**$ 80,000**	$ 80,000
OTP	Series 2007B Senior Unsecured Notes	6.15%	08/20/22	**—**	30,000
OTP	Series 2007C Senior Unsecured Notes	6.37%	08/02/27	**42,000**	42,000
OTP	Series 2013A Senior Unsecured Notes	4.68%	02/27/29	**60,000**	60,000
OTP	Series 2019A Senior Unsecured Notes	3.07%	10/10/29	**10,000**	10,000
OTP	Series 2020A Senior Unsecured Notes	3.22%	02/25/30	**10,000**	10,000
OTP	Series 2020B Senior Unsecured Notes	3.22%	08/20/30	**40,000**	40,000
OTP	Series 2021A Senior Unsecured Notes	2.74%	11/29/31	**40,000**	40,000
OTP	Series 2007D Senior Unsecured Notes	6.47%	08/20/37	**50,000**	50,000
OTP	Series 2019B Senior Unsecured Notes	3.52%	10/10/39	**26,000**	26,000
OTP	Series 2020C Senior Unsecured Notes	3.62%	02/25/40	**10,000**	10,000
OTP	Series 2013B Senior Unsecured Notes	5.47%	02/27/44	**90,000**	90,000
OTP	Series 2018A Senior Unsecured Notes	4.07%	02/07/48	**100,000**	100,000
OTP	Series 2019C Senior Unsecured Notes	3.82%	10/10/49	**64,000**	64,000
OTP	Series 2020D Senior Unsecured Notes	3.92%	02/25/50	**15,000**	15,000
OTP	Series 2021B Senior Unsecured Notes	3.69%	11/29/51	**100,000**	100,000
OTP	Series 2022A Senior Unsecured Notes	3.77%	05/20/52	**90,000**	—
Total				**827,000**	767,000
Less: Current Maturities Net of Unamortized Debt Issuance Costs				**—**	29,983
Unamortized Long-Term Debt Issuance Costs				**3,179**	3,003
Total Long-Term Debt Net of Unamortized Debt Issuance Costs				**$ 823,821**	$ 734,014

On June 10, 2021, OTP entered into a Note Purchase Agreement pursuant to which OTP agreed to issue, in a private placement transaction, $230.0 million of senior unsecured notes consisting of (a) $40.0 million of 2.74% Series 2021A Senior Unsecured Notes due November 29, 2031, (b) $100.0 million of 3.69% Series 2021B Senior Unsecured Notes due November 29, 2051 and (c) $90.0 million of 3.77% Series 2022A Senior Unsecured Notes due May 20, 2052. During the year ended December 31, 2021, OTP issued its Series 2021A and Series 2021B notes for aggregate proceeds of $140.0 million, which were used to repay the Series 2011A notes. During the year ended December 31, 2022, OTP issued its Series 2022A notes for aggregate proceeds of $90.0 million, which were used to repay the Series 2007B notes, to repay short-term borrowings, to fund capital expenditures, and for other general corporate purposes.

Our guaranteed and unsecured notes require the borrower to maintain various financial covenants, as further described below. These notes provide for prepayment options allowing for a full or partial prepayment at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount, as defined. These notes also include restrictions on the borrowers, including its ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties.

Aggregate maturities of long-term debt obligations at December 31, 2022 for each of the next five years are as follows:

(in thousands)	*2023*	*2024*	*2025*	*2026*	*2027*
Debt Maturities	$ —	$ —	$ —	$ 80,000	$ 42,000

Financial Covenants

Certain of OTC's and OTP's short-term and long-term debt agreements require the borrower, whether OTC or OTP, to maintain certain financial covenants, including a maximum debt to total capitalization of 0.60 to 1.00, a minimum interest and dividend coverage ratio of 1.50 to 1.00, and a maximum level of priority indebtedness. As of December 31, 2022, OTC and OTP were in compliance with these financial covenants.

10. Employee Postretirement Benefits

Pension Plan and Other Postretirement Benefits

The Company sponsors a noncontributory funded pension plan (the Pension Plan), an unfunded, nonqualified Executive Survivor and Supplemental Retirement Plan (ESSRP), both accounted for as defined benefit pension plans, and a postretirement healthcare plan accounted for as an other postretirement benefit plan.

The Pension Plan, which previously covered substantially all corporate and OTP employees, was closed to new employees in 2013. The plan provides retirement compensation to all covered employees at age 65, with reduced compensation in cases of retirement prior to age 62.

Participants are fully vested after completing five years of vesting service. The plan assets consist of equity funds, fixed income funds, cash and cash equivalents and alternative investments. None of the plan assets are invested in common stock or debt securities of the Company.

The ESSRP, an unfunded plan, provides for defined benefit payments to executive officers and certain key management employees on their retirement for life, or to their beneficiaries on their death. The ESSRP was amended and restated in 2019 to i) freeze the participation in the restoration retirement benefit component of the plan and ii) freeze benefit accruals under the restoration retirement benefit component of the plan for all participants of the plan except any participants deemed to be grandfathered participants.

The postretirement healthcare plan, closed to new participants in 2010, provides a portion of health insurance benefits for retired and covered corporate and OTP employees. To be eligible for retiree health insurance benefits, the employee must be 55 years of age with a minimum of 10 years of service. The plan is an unfunded plan and accordingly holds no plan assets.

Pension Plan Assets. We have established a Retirement Plans Administration Committee to develop and monitor our investment strategy for our Pension Plan assets. Our investment strategy includes the following objectives:

- The assets of the plan will be invested in accordance with all applicable laws in a manner consistent with fiduciary standards including Employee Retirement Income Security Act standards of 1974 (ERISA) (if applicable). Specifically:
    - The safeguards and diversity that a prudent investor would adhere to must be present in the investment program.
    - All transactions undertaken on behalf of the Pension Plan must be in the best interest of plan participants and their beneficiaries.
- The primary objective is to provide a source of retirement income for its participants and beneficiaries.
- The near-term primary financial objective is to improve and protect the funded status of the plan.
- A secondary financial objective is to minimize pension funding and expense volatility where possible.

We have developed an asset allocation target, measured at investment market value, to provide guideline percentages of investment mix. This investment mix is intended to achieve the financial objectives of the plan. The permitted range is a guide and will at times not reflect the actual asset allocation due to market conditions, actions of our investment managers and required cash flows to and from the Pension Plan.

The following table presents our target asset allocation permitted range along with the actual asset allocation as of December 31, 2022 and 2021:

	Permitted	Actual Allocation	
Asset Class	***Range***	***2022***	***2021***
Return Enhancement	35 – 60%	**48 %**	47 %
Risk Management	40 – 80%	**51**	50
Alternatives	0 – 20%	**1**	3
Total		**100 %**	100 %

Return Enhancement investments are those that seek to provide equity-like, long-term capital appreciation. Examples include equity securities, including dynamic asset allocation funds, and higher yielding fixed income securities, such as high yield bonds and emerging market debt.

Risk Management investments seek to decrease downside risk or act as a hedge against plan liabilities. Examples are cash and fixed income instruments.

Alternative investments seek to either provide return enhancement through long-term appreciation or risk management through decreased downside risk. The defining characteristic of these asset types is uncorrelated source of returns, less liquidity and private market access. Examples include investments in the SEI Energy Debt Collective Fund.

The following presents the fair value inputs classified within the fair value hierarchy used to measure Pension Plan assets at December 31, 2022 and 2021 and assets measured using the net asset value (NAV) practical expedient:

(in thousands)	*Level 1*	*Level 2*	*Level 3*	*NAV*	*Total*
December 31, 2022					
Equity Funds	**$ 124,327**	**$ —**	**$ —**	**$ —**	**$ 124,327**
Fixed Income Funds	**156,424**	**—**	**—**	**—**	**156,424**
Hybrid Funds	**9,756**	**—**	**—**	**—**	**9,756**
U.S. Treasury Securities	**19,588**	**—**	**—**	**—**	**19,588**
SEI Energy Debt Collective Fund	**—**	**—**	**—**	**3,703**	**3,703**
Total	**310,095**	**—**	**—**	**3,703**	**313,798**
December 31, 2021					
Equity Funds	149,479	—	—	—	149,479
Fixed Income Funds	184,987	—	—	—	184,987
Hybrid Funds	11,776	—	—	—	11,776
U.S. Treasury Securities	28,173	—	—	—	28,173
SEI Energy Debt Collective Fund	—	—	—	12,797	12,797
Total	$ 374,415	$ —	$ —	$ 12,797	$ 387,212

The investments held by the SEI Energy Debt Collective Fund on December 31, 2022 and 2021 consist mainly of below investment grade high yield bonds and loans of U.S. energy companies which trade at a discount to fair value. Redemptions are allowed semi-annually with a 95-day notice period, subject to fund director consent and certain gate, holdback and suspension restrictions. Subscriptions are allowed monthly with a three-year lock up on subscriptions. The fund's assets are valued in accordance with valuations reported by the fund's sub-advisor or the fund's underlying investments or other independent third-party sources, although SEI in its discretion may use other valuation methods, subject to compliance with ERISA, as applicable. On an annual basis, as determined by the investment manager in its sole discretion, an independent valuation agent is retained to provide a valuation of the illiquid assets of the fund and of any other asset of the fund.

Funded Status. The following table provides a reconciliation of the changes in the fair value of plan assets and the actuarially computed benefit obligation for the years ended December 31, 2022 and 2021 and the funded status of the plans as of December 31, 2022 and 2021:

	Pension Benefits (Pension Plan)		*Pension Benefits (ESSRP)*		*Postretirement Benefits*	
(in thousands)	*2022*	*2021*	*2022*	*2021*	*2022*	*2021*
Change in Fair Value of Plan Assets:						
Fair Value of Plan Assets at January 1	**$ 387,212**	$ 360,678	**$ —**	$ —	**$ —**	$ —
Actual Return on Plan Assets	**(76,485)**	32,816	**—**	—	**—**	—
Company Contributions	**20,000**	10,000	**2,205**	1,562	**2,294**	2,695
Benefit Payments	**(16,930)**	(16,282)	**(2,205)**	(1,562)	**(8,173)**	(8,385)
Participant Premium Payments	**—**	—	**—**	—	**5,879**	5,690
Fair Value of Plan Assets at December 31	**313,797**	387,212	**—**	—	**—**	—
Change in Benefit Obligation:						
Benefit Obligation at January 1	**416,697**	428,396	**46,840**	47,894	**69,311**	70,185
Service Cost	**6,576**	7,462	**195**	187	**1,338**	1,722
Interest Cost	**12,344**	11,660	**1,341**	1,228	**2,041**	1,891
Benefit Payments	**(16,930)**	(16,282)	**(2,205)**	(1,562)	**(8,172)**	(8,385)
Participant Premium Payments	**—**	—	**—**	—	**5,879**	5,690
Plan Amendments	**—**	—	**—**	—	**—**	—
Actuarial Loss	**(110,632)**	(14,539)	**(10,547)**	(907)	**(20,450)**	(1,792)
Benefit Obligation at December 31	**308,055**	416,697	**35,624**	46,840	**49,947**	69,311
Funded Status	**$ 5,742**	$ (29,485)	**$ (35,624)**	$ (46,840)	**$ (49,947)**	$ (69,311)
Amounts Recognized in Consolidated Balance Sheet at December 31:						
Noncurrent Assets	**$ 5,742**	$ —	**$ —**	$ —	**$ —**	$ —
Current Liabilities	**—**	—	**(2,414)**	(2,352)	**(2,970)**	(2,830)
Noncurrent Liabilities and Deferred Credits	**—**	(29,485)	**(33,210)**	(44,488)	**(46,977)**	(66,481)
Net Asset (Liability)	**$ 5,742**	$ (29,485)	**$ (35,624)**	$ (46,840)	**$ (49,947)**	$ (69,311)

The accumulated benefit obligation of our Pension Plan was $283.2 million and $378.3 million as of December 31, 2022 and 2021. The accumulated benefit obligation of our ESSRP was $35.6 million and $46.8 million as of December 31, 2022 and 2021.

The following assumptions were used to determine benefit obligations as of December 31, 2022 and 2021:

	Pension Benefits (Pension Plan)		*Pension Benefits (ESSRP)*		*Postretirement Benefits*	
	2022	***2021***	***2022***	***2021***	***2022***	***2021***
Discount Rate	**5.51 %**	3.03 %	**5.51 %**	2.93 %	**5.52 %**	3.01 %
Long-Term Rate of Compensation Increase[(1)]	**n/a**	n/a	**3.00 %**	3.00 %	**n/a**	n/a
Participants to Age 39[(1)]	**4.50 %**	4.50 %	**n/a**	n/a	**n/a**	n/a
Participants Ages 40 to 49[(1)]	**3.50 %**	3.50 %	**n/a**	n/a	**n/a**	n/a
Participants Age 50 and Older[(1)]	**2.75 %**	2.75 %	**n/a**	n/a	**n/a**	n/a
Healthcare Cost Immediate Trend Rate	**n/a**	n/a	**n/a**	n/a	**7.50 %**	6.16 %
Healthcare Cost Ultimate Trend Rate	**n/a**	n/a	**n/a**	n/a	**4.00 %**	4.50 %
Year the Rate Reaches the Ultimate Trend Rate	**n/a**	n/a	**n/a**	n/a	**2048**	2038

[(1)] The estimated rate of compensation increase for 2023 and 2024, as estimated as of December 31, 2022, is equal to 4.00% for all participants, reflecting higher anticipated compensation changes during these years.

The measurement of the plan asset or benefit obligation recognized for our Pension Plan, ESSRP and postretirement healthcare benefit plan included the following significant actuarial adjustments:

- For the Pension Plan, an increase in the discount rate in 2022 and 2021 reduced our obligation by $117.1 million and $15.7 million. A short-term increase in expected future compensation increased the benefit obligation in 2022 by $6.8 million. The difference between actual and expected returns on Pension Plan assets also impacted our obligation in 2022 and 2021.
- For the ESSRP, an increase in the discount rate in 2022 and 2021 reduced our obligation by $10.2 million and $1.7 million.
- For the postretirement healthcare plan, an increase in the discount rate in 2022 and 2021 reduced our obligation by $17.9 million and $2.6 million. Revised estimates of healthcare cost trends and participant contribution assumptions decreased the benefit obligation by $2.4 million in 2022.

Net Periodic Benefit Cost. A portion of service cost may be capitalized as a cost of self-constructed property, plant and equipment. When recognized in the consolidated statements of income, service cost is recognized within one of the components of operating expenses. Nonservice cost components of net periodic benefit cost may be deferred and recognized as a regulatory asset under the accounting guidance for regulated operations. When recognized in the consolidated statements of income, nonservice cost components are recognized as nonservice cost components of postretirement benefits.

The following table lists the components of net periodic benefit cost of our defined benefit pension plans and other postretirement benefits for the years ended December 31, 2022, 2021 and 2020:

	Pension Benefits (Pension Plan)			*Pension Benefits (ESSRP)*			*Postretirement Benefits*		
(in thousands)	***2022***	***2021***	***2020***	***2022***	***2021***	***2020***	***2022***	***2021***	***2020***
Service Cost	**$ 6,576**	$ 7,462	$ 6,621	**$ 195**	$ 187	$ 179	**$ 1,338**	$ 1,722	$ 1,847
Interest Cost	**12,344**	11,660	13,053	**1,341**	1,228	1,449	**2,041**	1,891	2,393
Expected Return on Assets	**(23,684)**	(22,359)	(22,021)	**—**	—	—	**—**	—	—
Amortization of Prior Service Cost	**—**	—	—	**—**	—	—	**(5,733)**	(5,733)	(4,792)
Amortization of Net Actuarial Loss	**7,865**	10,914	9,144	**567**	620	434	**3,063**	3,774	4,310
Net Periodic Benefit Cost	**$ 3,101**	$ 7,677	$ 6,797	**$ 2,103**	$ 2,035	$ 2,062	**$ 709**	$ 1,654	$ 3,758

The following table includes the impact of regulation on the recognition of periodic benefit cost arising from pension and other postretirement benefits for the years ended December 31, 2022, 2021 and 2020:

(in thousands)	***2022***	***2021***	***2020***
Net Periodic Benefit Cost	**$ 5,913**	$ 11,366	$ 12,617
Net Amount Amortized (Deferred) Due to the Effect of Regulation	**1,121**	21	(533)
Net Periodic Benefit Cost Recognized	**$ 7,034**	$ 11,387	$ 12,084

The following assumptions were used to determine net periodic benefit cost for the years ended December 31, 2022, 2021 and 2020:

	Pension Benefits (Pension Plan)			Pension Benefits (ESSRP)			Postretirement Benefits		
	2022	**2021**	**2020**	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
Discount Rate	**3.03 %**	2.78 %	3.47 %	**2.93 %**	2.61 %	3.36 %	**3.01 %**	2.75 %	3.43 %
Long-Term Rate of Return on Plan Assets	**6.30 %**	6.51 %	6.88 %	**n/a**	n/a	n/a	**n/a**	n/a	n/a
Long-Term Rate of Compensation Increase	**n/a**	n/a	n/a	**3.00 %**	3.00 %	3.50 %	**n/a**	n/a	n/a
Participants to Age 39	**4.50 %**	4.50 %	4.50 %	**n/a**	n/a	n/a	**n/a**	n/a	n/a
Participants Ages 40 to 49	**3.50 %**	3.50 %	3.50 %	**n/a**	n/a	n/a	**n/a**	n/a	n/a
Participants Age 50 and Older	**2.75 %**	2.75 %	2.75 %	**n/a**	n/a	n/a	**n/a**	n/a	n/a

We develop our estimated discount rate through the use of a hypothetical bond portfolio method. This method derives the discount rate from the average yield of a collection of high credit quality bonds which produce cash flows similar to our anticipated future benefit payments. We estimate the assumed long-term rate of return on plan assets based primarily on asset category studies using historical market return and volatility data with forward-looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically.

The following table presents the amounts not yet recognized as components of net periodic benefit cost as of December 31, 2022 and 2021:

	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
(in thousands)	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**
Regulatory Assets (Liabilities):						
Unrecognized Prior Service Cost	**$ —**	$ —	**$ —**	$ —	**$ (8,400)**	$ (13,989)
Unrecognized Actuarial Loss	**85,367**	102,737	**979**	2,525	**3,993**	26,852
Net Regulatory Assets (Liabilities)	**85,367**	102,737	**979**	2,525	**(4,407)**	12,863
Accumulated Other Comprehensive Income (Loss):						
Unrecognized Prior Service Cost	**—**	—	**—**	—	**(99)**	(242)
Unrecognized Actuarial (Gain) Loss	**(1,978)**	(1,020)	**1,093**	10,660	**(818)**	(160)
Total Accumulated Other Comprehensive Income (Loss)	**$ (1,978)**	$ (1,020)	**$ 1,093**	$ 10,660	**$ (917)**	$ (402)

Cash Flows. We made discretionary contributions to our Pension Plan of $20.0 million, $10.0 million and $11.2 million in 2022, 2021 and 2020. As of December 31, 2022, we had no minimum funding requirements for our Pension Plan. Contributions to our ESSRP and postretirement healthcare plan are equal to the benefits paid to plan participants.

The following reflects anticipated benefit payments to be paid in each of the next five years and in the aggregate for the five year period thereafter under our pension plans and postretirement healthcare plan:

(in thousands)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028-2032**
Projected Pension Plan Benefit Payments	$ 18,023	$ 18,556	$ 19,073	$ 19,565	$ 20,015	$ 106,067
Projected ESSRP Benefit Payments	2,475	2,764	2,702	2,821	2,987	14,507
Projected Postretirement Benefit Payments	2,970	3,090	3,297	3,451	3,495	17,804
Total	$ 23,468	$ 24,410	$ 25,072	$ 25,837	$ 26,497	$ 138,378

401K Plan

We sponsor a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans totaled $6.7 million for 2022, $6.5 million for 2021 and $5.3 million for 2020.

11. Asset Retirement Obligations

We have recognized Asset Retirement Obligations (AROs) related to our coal-fired generation plants, natural gas combustion turbines and wind turbines. The cost of AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. We have other legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. We have no assets legally restricted for the settlement of any AROs.

A reconciliation of the carrying amounts of AROs for the years ended December 31, 2022 and 2021 is as follows:

(in thousands)		*2022*		*2021*
Beginning Balance	**$**	**24,191**	$	23,821
Adjustments Due to Revisions in Cash Flow Estimates		**—**		(568)
Accrued Accretion		**991**		938
Ending Balance	**$**	**25,182**	$	24,191

12. Income Taxes

Income before income taxes for the years ended December 31, 2022, 2021 and 2020 consists entirely of domestic earnings.

The provision for income taxes charged to income for the years ended December 31, 2022, 2021 and 2020 consisted of the following:

(in thousands)		*2022*		*2021*		*2020*
Current						
Federal Income Taxes	**$**	**31,949**	$	6,806	$	3,631
State Income Taxes		**9,568**		939		2,415
Deferred						
Federal Income Taxes		**22,480**		18,180		11,450
State Income Taxes		**9,943**		10,716		3,751
Tax Credits						
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		**(586)**		(586)		(1,033)
Investment Tax Credit Amortization		**(3)**		(3)		(8)
Total	**$**	**73,351**	$	36,052	$	20,206

The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2022, 2021 and 2020 is as follows:

		2022			*2021*			*2020*	
Income Taxes at Federal Statutory Rate	**$**	**75,082**	**21.0 %**	$	44,692	21.0 %	$	24,372	21.0 %
Increases (Decreases) in Tax from:									
State Taxes on Income, Net of Federal Tax		**15,049**	**4.2**		9,962	4.7		4,597	4.0
Production Tax Credits (PTCs)		**(14,985)**	**(4.2)**		(12,503)	(5.9)		(1,250)	(1.1)
Amortization of Excess Deferred Income Taxes		**(1,625)**	**(0.5)**		(4,262)	(2.0)		(4,167)	(3.6)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		**(586)**	**(0.2)**		(586)	(0.3)		(1,033)	(0.9)
Allowance for Equity Funds Used During Construction		**(440)**	**(0.1)**		(214)	(0.1)		(796)	(0.7)
Other, Net		**856**	**0.3**		(1,037)	(0.5)		(1,517)	(1.3)
Income Taxes at Effective Tax Rate	**$**	**73,351**	**20.5 %**	$	36,052	16.9 %	$	20,206	17.4 %

We began to generate PTCs from our Merricourt wind farm in the fourth quarter of 2020, once the asset was placed in service and commenced operations.

Deferred tax assets and liabilities were composed of the following on December 31, 2022 and 2021:

(in thousands)		*2022*		*2021*
Deferred Tax Assets				
Employee Benefits	**$**	**39,216**	$	41,842
Regulatory Liabilities		**57,353**		75,293
Tax Credit Carryforwards, net of federal impact		**20,209**		27,965
Cost of Removal		**37,360**		26,512
Net Operating Loss Carryforward, net of federal impact		**1,853**		1,323
Other		**12,107**		11,067
Total Deferred Tax Assets		**168,098**		184,002
Deferred Tax Liabilities				
Differences Related to Property		**(334,201)**		(297,981)
Retirement Benefits Regulatory Asset		**(22,789)**		(40,766)
Pension Expense		**(24,269)**		(24,578)
Other		**(8,141)**		(8,945)
Total Deferred Tax Liabilities		**(389,400)**		(372,270)
Deferred Income Taxes	**$**	**(221,302)**	$	(188,268)

The following is a schedule of tax credits and tax net operating losses available as of December 31, 2022 and the respective periods of expiration:

(in thousands)		*Amount*		*2023-2029*		*2030-2037*		*2038-2043*
State Net Operating Losses	**$**	**2,348**	$	—	$	2,348	$	—
State Tax Credits		**25,578**		—		—		25,578

The following table summarizes the activity for unrecognized tax benefits for the years ended December 31, 2022, 2021 and 2020:

(in thousands)		*2022*		*2021*		*2020*
Balance on January 1	**$**	**827**	$	771	$	1,488
Increases (decreases) for tax positions taken during a prior period		**44**		11		(178)
Increases for tax positions taken during the current period		**260**		189		175
Decreases due to settlements with taxing authorities		**—**		—		(575)
Decreases as a result of a lapse of applicable statutes of limitations		**(208)**		(144)		(139)
Balance on December 31	**$**	**923**	$	827	$	771

The balance of unrecognized tax benefits as of December 31, 2022 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2022 is not expected to change significantly within the next 12 months. We classify interest and penalties on tax uncertainties as components of the provision for income taxes in the consolidated statements of income.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2022, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2019 for federal and North Dakota income taxes and prior to 2018 for Minnesota state income taxes.

13. Commitments and Contingencies

Commitments

Ashtabula III Purchase. Since 2013, OTP had purchased the wind-generated electricity from the Ashtabula III, a 62.4-megawatt wind farm located in eastern North Dakota, pursuant to a power purchase agreement. That agreement granted OTP the option to purchase the wind farm, and in June 2022, OTP exercised its option. On January 3, 2023, OTP acquired Ashtabula III for $50.6 million.

Construction and Other Commitments. As of December 31, 2022, OTP had commitments under contracts for construction project materials, plant maintenance, and other services extending into 2046 which totaled approximately $21.5 million.

Electric Utility Capacity and Energy Requirements. OTP has commitments for the purchase of capacity and energy requirements under contractual agreements, including wind power purchase agreements extending into 2033. Generally, the terms of OTP's wind power purchase agreements require OTP to purchase all of the electricity generated by a particular wind farm and do not include fixed or minimum payments. The required payments are variable and the amounts due are determined based upon the amount of electricity generated. Capacity and energy requirement costs under these agreements totaled $13.1 million, $11.5 million and $11.3 million for the years ended December 31, 2022, 2021 and 2020.

Coal Purchase Commitments. OTP has contracts providing for the purchase and delivery of its coal requirements. OTP's current coal purchase agreement with CCMC for Coyote Station expires December 31, 2040. All of Coyote Station's coal requirements for the period covered must be purchased under this agreement. The agreement is structured so that the price of the coal covers all of CCMC's operating, financing, and future mine reclamation costs. In the table below we have estimated the future payments to be made under the terms of the agreement until its maturity. OTP has an agreement for the purchase of Big Stone Plant's coal requirements through December 31, 2024. There is no fixed minimum purchase requirement under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement. Coal purchase costs under these agreements totaled $45.1 million, $40.4 million and $37.9 million for the years ended December 31, 2022, 2021 and 2020.

Land Easement Payments. OTP has commitments to make payments for land easements not classified as leases, extending into 2050 of approximately $33.1 million. Land easement costs under these agreements totaled $1.4 million, $1.3 million and $1.3 million for the years ended December 31, 2022, 2021 and 2020.

Our future commitments as of December 31, 2022 were as follows:

(in thousands)	*Construction Program and Other Commitments*	*Capacity and Energy Requirements*	*Coal Purchase Commitments*	*Land Easement Payments*
2023	$ 12,423	$ 298	$ 23,955	$ 1,388
2024	934	272	24,369	1,412
2025	472	228	25,103	1,437
2026	479	197	25,716	1,432
2027	487	197	25,804	1,457
Beyond 2027	6,660	3,939	402,500	26,004
Total	$ 21,455	$ 5,131	$ 527,447	$ 33,130

Contingencies

FERC ROE. In November 2013 and February 2015, customers filed complaints with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO tariff rate. FERC's most recent order, issued on November 19, 2020, adopted a revised ROE methodology and set the base ROE at 10.02% (10.52% with an adder) effective for the fifteen-month period from November 2013 to February 2015 and on a prospective basis beginning in September 2016. The order also dismissed any complaints covering the period from February 2015 to May 2016. On August 9, 2022, the U.S. Court of Appeals for the District of Columbia Circuit vacated the FERC order citing a lack of reasoned explanation by FERC in its adoption of its revised ROE methodology as outlined in its November 2020 order. The U.S. Court of Appeals remanded the matter to FERC to reopen the proceedings.

Significant uncertainty exists as to how FERC will proceed on remand and there is no prescribed timeline under which FERC must act. We have deferred recognition and recorded a refund liability of $2.6 million as of December 31, 2022. This refund liability reflects our best estimate of amounts previously collected from customers under the MISO tariff rate that may be required to be refunded to customers once all regulatory and judicial proceedings are complete and a final ROE is established for the periods outlined above.

Regional Haze Rule (RHR). The RHR was adopted in an effort to improve visibility in national parks and wilderness areas. The RHR requires states, in coordination with the Environmental Protection Agency and other governmental agencies, to develop and implement plans to achieve natural visibility conditions. The second RHR implementation period covers the years 2018-2028. States are required to submit a state implementation plan to assess reasonable progress with the RHR and determine what additional emission reductions are appropriate, if any.

Coyote Station, OTP's jointly-owned coal-fired power plant in North Dakota, is subject to assessment in the second implementation period under the North Dakota state implementation plan. The NDDEQ submitted its state implementation plan to the EPA for approval in August 2022. In its plan, the NDDEQ concluded it is not reasonable to require additional emission controls during this planning period. The EPA has previously expressed disagreement with the NDDEQ's recommendation to forgo additional emission controls and has indicated that such a plan is not likely to be accepted.

We cannot predict with certainty the impact the state implementation plan may have on our business until the state implementation plan has been approved or otherwise acted on by the EPA. However, significant emission control investments could be required and the recovery of such costs from customers would require regulatory approval. Alternatively, investments in emission control equipment may prove to be uneconomic and result in the early retirement of or the sale of our interest in Coyote Station, subject to regulatory approval. We cannot estimate the ultimate financial effects such a retirement or sale may have on our consolidated operating results, financial position or cash flows, but such amounts could be material and the recovery of such costs in rates would be subject to regulatory approval.

Self-Funding of Transmission Upgrades. The FERC has granted transmission owners within MISO the unilateral authority to determine the funding mechanism for interconnection transmission upgrades that are necessary to accommodate new generation facilities connecting to the electrical grid. Under existing FERC orders, transmission owners can unilaterally determine whether the generator pays the transmission owner in advance for the transmission upgrade or, alternatively, the transmission owner can elect to fund the upgrade and recover over time from the generator the cost of and a return on the upgrade investment (a self-funding). FERC's orders granting transmission owners this unilateral funding authority has been judicially contested on the basis that transmission owners may be motivated to discriminate among generators in making funding determinations. In the most recent judicial hearing, the petitioners argued to the U.S. Court of Appeals for the District of Columbia that FERC did not comply with a previous judicial order to fully develop a record regarding the risk of discrimination and the financial risk absorbed by transmission owners for generator-funded upgrades. On December 2, 2022, the Court of Appeals ruled in favor of the petitioners remanding the matter to FERC, instructing the agency to adequately explain the basis of its orders. The Court of Appeals decision did not vacate transmission owners' unilateral funding authority.

OTP, as a transmission owner in MISO, has exercised its authority and elected to self-fund previous transmission upgrades necessary to accommodate new system generation. Under such an election, OTP is recovering the cost of the transmission upgrade and a return on that investment from the generator over a contractual period of time. Should FERC, on remand from the Court of Appeals, eliminate transmission owners' unilateral funding authority, on either a prospective or retrospective basis, our financial results would be impacted. We cannot at this time reasonably predict the outcome of this matter given the uncertainty as to how and when FERC may respond to the judicial remand.

Other Contingencies. We are party to litigation and regulatory enforcement matters arising in the normal course of business. We regularly analyze relevant information and, as necessary, estimate and record accrued liabilities for matters in which a loss is probable of occurring and can be reasonably estimated. We believe the effect on our consolidated operating results, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2022 will not be material.

14. Stockholders' Equity

Capital Structure
In addition to authorized and outstanding common stock, the Company has 1,500,000 authorized no par value cumulative preferred shares and 1,000,000 authorized no par value cumulative preference shares. No cumulative preferred or cumulative preference shares were outstanding at December 31, 2022 or 2021.

Shelf Registrations
On May 3, 2021, upon the expiration of a prior shelf registration, we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. The registration statement expires in May 2024. No shares were issued pursuant to the shelf registration in 2022.

On May 3, 2021, upon the expiration of a second prior shelf registration, we filed a second registration statement with the SEC for the issuance of up to 1,500,000 common shares under an Automatic Dividend Reinvestment and Share Purchase Plan, which provides shareholders, retail customers of OTP and other interested investors a method of purchasing our common shares by reinvesting their dividends and/or making optional cash investments. Shares purchased under the plan may be new issue common shares or common shares purchased on the open market. In 2022, we issued 133,827 common shares under this program and no proceeds were received, as all shares issued were purchased on the open market. As of December 31, 2022, 1,250,993 shares remain available for purchase or issuance under the Plan. The shelf registration for the plan expires in May 2024.

Dividend Restrictions
OTC is a holding company with no significant operations of its own. The primary source of funds for payments of dividends to our shareholders is from dividends paid or distributions made by OTC's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by OTC's subsidiaries. Both the OTC Credit Agreement and OTP Credit Agreement contain restrictions on the payment of cash dividends upon a default or event of default, including failure to maintain certain financial covenants. As of December 31, 2022, we were in compliance with these financial covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act and the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as i) the source of the dividends is clearly disclosed, ii) the dividend is not excessive and iii) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to OTC by requiring an equity-to-total-capitalization ratio between 47.5% and 58.0%, with total capitalization not to exceed $1.8 billion based on OTP's capital structure requirements as of December 31, 2022. As of December 31, 2022, OTP's equity-to-total-capitalization ratio including short-term debt was 54.7% and its net assets restricted from distribution totaled approximately $737.4 million.

15. Accumulated Other Comprehensive Income (Loss)

The Company's other comprehensive income consists of unamortized actuarial losses and prior service costs related to pension and other postretirement benefits and unrealized gains and losses on marketable securities classified as available-for-sale. The income tax expense or benefit associated with amounts reclassified from accumulated other comprehensive income (loss) and reflected in the consolidated statement of income are recognized in the same period as the amounts are reclassified.

The following table shows the changes in accumulated other comprehensive Income (loss) for the years ended December 31, 2022, 2021 and 2020:

(in thousands)	*Pension and Other Postretirement Benefits*	*Net Unrealized Gain (Losses) on Available-for-Sale Securities*	*Total*
Balance, December 31, 2019	$ (6,491)	$ 54	$ (6,437)
Other Comprehensive Income Before Reclassifications, net of tax	418	145	563
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(2,643) (1)	10 (2)	(2,633)
Total Other Comprehensive Income (Loss)	(2,225)	155	(2,070)
Balance, December 31, 2020	(8,716)	209	(8,507)
Other Comprehensive Income (Loss) Before Reclassifications, net of tax	1,638	(132)	1,506
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	541 (1)	(64) (2)	477
Total Other Comprehensive Income (Loss)	2,179	(196)	1,983
Balance, December 31, 2021	(6,537)	13	(6,524)
Other Comprehensive Income (Loss) Before Reclassifications, net of tax	7,331	(433)	6,898
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	540 (1)	1 (2)	541
Total Other Comprehensive Income (Loss)	7,871	(432)	7,439
Balance, December 31, 2022	**$ 1,334**	**$ (419)**	**$ 915**

(1) *Included in the computation of net periodic pension and other postretirement benefit costs. See Note 10 for further information.*

(2) *Included in other income (expense), net on the accompanying consolidated statements of income.*

16. Share-Based Payments

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan authorizes the issuance of 1,400,000 common shares, allowing eligible employees to purchase our common shares through payroll withholding at a discount of up to 15% off the market price at the end of each six-month purchase period. Employee withholding amounts may not be less than $10 or more than $2,000 per month, subject to certain limitations, as described in the plan. A plan participant may cease making payroll deductions at any time. A participant may not purchase more than 2,000 shares in a given six month purchase period under the plan and may not purchase more than $25,000 (fair market value) of common shares under the plan and all other purchase plans (if any) in a calendar year. A participant may withdraw from the plan at any time and elect to receive the balance of their contributions to the plan that have not yet been used to purchase shares in cash. Shares purchased under the plan are automatically enrolled in the Company's dividend reinvestment plan. Shares purchased under the plan may not be assigned, transferred, pledged, or otherwise disposed, except for certain situations allowed by the plan, such as upon death, for a period of 18 months after purchase. At our discretion, shares purchased under the plan can be either new issue shares or shares purchased in the open market. The plan shall automatically terminate when all of the shares authorized under the plan have been issued.

We recognize the 15% discount to the fair market value of the purchased shares as stock-based compensation expense, which amounted to $0.3 million, $0.2 million and $0.2 million for the years ended December 31, 2022, 2021, and 2020. For the years ended December 31, 2022, 2021, and 2020 the amount of shares issued under the plan amounted to 26,420, 27,975 and 31,661 shares. As of December 31, 2022, there were 263,706 shares available for purchase under the plan.

Share-Based Compensation Plan

The 2014 Stock Incentive Plan, which was approved by our shareholders in April 2014, authorizes the issuance of 1,900,000 common shares for the granting of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards and other stock and stock-based awards. As of December 31, 2022, 587,211 shares were available for issuance under the plan. The plan terminates on December 31, 2023.

We grant restricted stock awards to our employees and members of our Board of Directors and stock performance awards to our executive officers and certain other key employees as part of our long-term compensation and retention program. Stock-based compensation cost, recognized within operating expenses in the consolidated statements of income, amounted to $6.6 million, $6.7 million and $6.1 million for the years ended December 31, 2022, 2021 and 2020. The related income tax benefit recognized for these periods amounted to $1.7 million, $1.8 million and $2.1 million.

Restricted Stock Awards. Restricted stock awards are granted to executive officers and other key employees and members of the Company's Board of Directors. The awards vest, depending on award recipient, either ratably over a period of three to four years or cliff vest after four years. Vesting is accelerated in certain circumstances, including upon retirement. Awards granted to members of the Board of Directors are issued and outstanding upon grant and carry the same voting and dividend rights of unrestricted outstanding common stock. Awards granted to executive officers and other key employees are eligible to receive dividend equivalent payments during the vesting period, subject to forfeiture under the terms of the agreement, but such awards are not issued or outstanding upon grant and do not provide for voting rights.

The grant-date fair value of each restricted stock award is determined based on the market price of the Company's common stock on the date of grant adjusted to exclude the value of dividends for those awards that do not receive dividend or dividend equivalent payments during the vesting period.

The following is a summary of restricted stock award activity for the year ended December 31, 2022:

	Shares	*Weighted-Average Grant-Date Fair Value*
Nonvested, Beginning of Year	138,093	$ 44.48
Granted	51,600	59.95
Vested	(48,142)	45.35
Forfeited	—	—
Nonvested, End of Year	141,551	$ 49.83

The weighted-average grant-date fair value of granted awards was $59.95, $43.55 and $45.97 during the years ended December 31, 2022, 2021 and 2020. The fair value of vested awards was $3.0 million, $2.1 million and $2.8 million during the years ended December 31, 2022, 2021 and 2020. As of December 31, 2022, there was $2.9 million of unrecognized compensation costs for unvested restricted stock awards to be recognized over a weighted-average period of 1.84 years.

Stock Performance Awards. Stock performance awards are granted to executive officers and certain other key employees. The awards vest at the end of a three-year performance period. The number of common shares awarded, if any, at the end of the performance period ranges from zero to 150% of the target amount based on two performance measures: i) total shareholder return relative to a peer group (TSR component) and ii) return on equity (ROE component). The awards have no voting or dividend rights during the vesting period. Vesting of the awards is accelerated in certain circumstances, including upon retirement. The amount of common shares awarded on an accelerated vesting is based either on actual performance at the end of the performance period or the amount of common shares earned at target.

The grant-date fair value of the ROE component of the stock performance awards granted during the years ended December 31, 2022, 2021 and 2020 was determined using the grant date stock price and a discounted cash flow analysis to adjust for expected unearned dividends during the vesting period. The grant-date fair value of the TSR component of the stock performance awards granted during the years ended December 31, 2022, 2021 and 2020 was determined using a Monte Carlo fair value simulation model incorporating the following assumptions:

	2022	***2021***	***2020***
Risk-free interest rate	**1.52 %**	0.18 %	1.42 %
Expected term (in years)	**3.00**	3.00	3.00
Expected volatility	**32.00 %**	32.00 %	19.00 %
Dividend yield	**2.90 %**	3.60 %	2.80 %

The risk-free interest rate was derived from yields on U.S. government bonds of a similar term. The expected term of the award is equal to the three-year performance period. Expected volatility was estimated based on actual historical volatility of our common stock over a three- or five-year period. Dividend yield was estimated based on historic and future yield estimates.

The following is a summary of stock performance award activity for the year ended December 31, 2022 (share amounts reflect awards at target):

	Shares	*Weighted-Average Grant-Date Fair Value*
Nonvested, Beginning of Year	189,600	$ 42.54
Granted	55,800	54.91
Vested	(55,600)	43.30
Forfeited	—	—
Nonvested, End of Year	189,800	$ 45.95

The weighted-average grant-date fair value of granted awards was $54.91, $38.34 and $47.79 during the years ended December 31, 2022, 2021 and 2020. The fair value of vested awards was $5.1 million, $2.5 million and $3.4 million during the years ended December 31, 2022, 2021 and 2020. As of December 31, 2022, there was $0.4 million of unrecognized compensation costs of unvested stock performance awards to be recognized over a weighted-average period of 0.91 years.

17. Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per share is net income. The denominator used in the calculation of basic earnings per share is the weighted-average number of shares outstanding during the period. The denominator used in the calculation of diluted earnings per share is derived by adjusting basic shares outstanding for the dilutive effect of potential shares outstanding, which consist of time and performance based stock awards and employee stock purchase plan shares.

The following includes the computation of the denominator for basic and diluted weighted-average shares outstanding for the years ended December 31, 2022, 2021 and 2020:

(in thousands)	*2022*	*2021*	*2020*
Weighted Average Common Shares Outstanding – Basic	**41,586**	41,491	40,710
Effect of Dilutive Securities:			
Stock Performance Awards	**248**	226	116
Restricted Stock Awards	**95**	87	63
Employee Stock Purchase Plan Shares and Other	**2**	14	16
Dilutive Effect of Potential Common Shares	**345**	327	195
Weighted Average Common Shares Outstanding – Diluted	**41,931**	41,818	40,905

The amount of shares excluded from diluted weighted-average common shares outstanding because such shares were anti-dilutive was not material for the years ended December 31, 2022, 2021 and 2020.

18. Derivative Instruments

OTP enters into derivative instruments to manage its exposure to future commodity price variability and reduce volatility in prices for our retail electric customers. These derivative instruments are not designated as qualifying hedging transactions but provide for an economic hedge against future price variability. The instruments are recorded at fair value on the consolidated balance sheets, with changes in fair value recorded in the consolidated statements of income. However, in accordance with rate-making and cost recovery processes, we recognize a regulatory asset or liability to defer losses or gains from derivative activity until settlement of the associated derivative instrument.

As of December 31, 2022 and 2021, OTP had outstanding pay-fixed, receive-variable swap agreements with an aggregate notional amount of 295,000 and 263,400 megawatt-hours of electricity. The contracts outstanding as of December 31, 2022 had various settlement dates throughout 2023. As of December 31, 2022 and 2021, the fair value of these derivative instruments was $7.1 million, which is included in other current liabilities, and 6.2 million, which is included in other current assets, on the consolidated balance sheets. During the years ended December 31, 2022 and 2021, contracts matured and were settled in an aggregate amount of $1.0 million and $3.1 million.

19. Fair Value Measurements

The following tables present our assets measured at fair value on a recurring basis as of December 31, 2022 and 2021 classified by the input method used to measure fair value:

	Level 1	***Level 2***	***Level 3***
December 31, 2022			
Assets			
Investments:			
Money Market Funds	**$ 1,560**	**$ —**	**$ —**
Mutual Funds	**5,503**	**—**	**—**
Corporate Debt Securities	**—**	**1,434**	**—**
Government-Backed and Government-Sponsored Enterprises' Debt Securities	**—**	**7,327**	**—**
Total Assets	**7,063**	**8,761**	**—**
Liabilities			
Derivative Instruments	**—**	**7,130**	**—**
Total Liabilities	**$ —**	**$ 7,130**	**$ —**
December 31, 2021			
Assets			
Investments:			
Money Market Funds	$ 949	$ —	$ —
Mutual Funds	5,432	—	—
Corporate Debt Securities	—	1,333	—
Government-Backed and Government-Sponsored Enterprises' Debt Securities	—	7,869	—
Derivative Instruments	—	6,214	—
Total Assets	$ 6,381	$ 15,416	$ —

The level 2 fair value measurements for government-backed and government-sponsored enterprises' and corporate debt securities are determined on the basis of valuations provided by a third-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service may be based on broker quotes.

The level 2 fair value measurements for derivative instruments are determined by using inputs such as forward electric commodity prices, adjusted for location differences. These inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

In addition to assets recorded at fair value on a recurring basis, we also hold financial instruments that are not recorded at fair value in the consolidated balance sheets but for which disclosure of the fair value of these financial instruments is provided. The following reflects the carrying value and estimated fair value of these assets and liabilities as of December 31, 2022 and 2021:

	December 31, 2022		***December 31, 2021***	
(in thousands)	***Carrying Amount***	***Fair Value***	***Carrying Amount***	***Fair Value***
Assets:				
Cash and Cash Equivalents	**$ 118,996**	**$ 118,996**	$ 1,537	$ 1,537
Total	**118,996**	**118,996**	1,537	1,537
Liabilities:				
Short-Term Debt	**8,204**	**8,204**	91,163	91,163
Long-Term Debt	**823,821**	**681,615**	763,997	878,272
Total	**$ 832,025**	**$ 689,819**	$ 855,160	$ 969,435

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash Equivalents: The carrying amount approximates fair value because of the short-term maturity of these instruments.

Short-Term Debt: The carrying amount approximates fair value because the debt obligations are short-term in nature and balances outstanding are subject to variable rates of interest which reset frequently, a Level 2 fair value input.

Long-Term Debt: The fair value of long-term debt is estimated based on current market indications for borrowings of similar maturities with similar terms, a Level 2 fair value input.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosures Controls and Procedures. Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2022, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2022.

Changes in Internal Control over Financial Reporting. There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report Regarding Internal Control Over Financial Reporting. Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this report on Form 10-K. The consolidated financial statements of the Company have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). These internal controls are designed only to provide reasonable assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition.

Management has completed its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework* (*2013*) to conduct the required assessment of the effectiveness of the Company's internal control over financial reporting. Based on this assessment, management concluded that, as of December 31, 2022, the Company's internal control over financial reporting was effective based on those criteria. The Company's independent registered public accounting firm, Deloitte & Touche LLP, has audited the Company's consolidated financial statements included in this report on Form 10-K and issued an attestation report on the Company's internal control over financial reporting.

Attestation Report of Independent Registered Public Accounting Firm. The attestation report of Deloitte & Touche LLP, the Company's independent registered public accounting firm, regarding the Company's internal control over financial reporting is provided in Item 8 of this report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under “Election of Directors” in the Company's definitive Proxy Statement for the 2023 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A of this report on Form 10-K. The information required by this Item regarding the Company’s procedures for recommending nominees to the board of directors is incorporated by reference to the information under “Corporate Governance – Director Nomination Process” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting. The information required by this Item regarding the Audit Committee and the Company’s Audit Committee financial experts is incorporated by reference to the information under “Committees of the Board of Directors – Audit Committee” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

The Company has adopted a code of business ethics that applies to all of its directors, officers (including its principal executive officer, principal financial officer, and its principal accounting officer or controller or person performing similar functions) and employees. The Company’s code of business ethics is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of business ethics by posting such information on its website at the address specified above. Information on the Company’s website is not deemed to be incorporated by reference into this report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under “Compensation Discussion and Analysis”, “Report of Compensation and Human Capital Management Committee”, “Executive Compensation”, “Pay Ratio Disclosure” and “Director Compensation” in the Company's definitive Proxy Statement for the 2023 Annual Meeting.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item regarding the Company’s equity compensation plans is incorporated by reference to the information under “Equity Compensation Plan Information” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting. The information required by this Item regarding security ownership is incorporated by reference to the information under “Security Ownership of Certain Beneficial Owners” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information under “Policy and Procedures Regarding Transactions with Related Persons”, “Election of Directors” and “Committees of the Board of Directors” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under “Ratification of Independent Registered Public Accounting Firm – Fees” and “Ratification of Independent Registered Public Accounting Firm – Pre-Approval of Audit/Non-Audit Services Policy” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. Financial Statements

2. Financial Statement Schedules

Schedule I - Condensed Financial Information of Registrant

Schedule II - Valuation and Qualifying Accounts and Reserves

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
OTTER TAIL CORPORATION (PARENT COMPANY)
CONDENSED BALANCE SHEETS

	December 31,	
(in thousands)	***2022***	***2021***
Assets		
Current Assets		
Cash and Cash Equivalents	**$ 119,246**	$ 3
Accounts Receivable	**—**	25
Accounts Receivable from Subsidiaries	**3,278**	2,817
Interest Receivable from Subsidiaries	**117**	117
Notes Receivable from Subsidiaries	**—**	6,767
Other	**1,045**	1,410
Total Current Assets	**123,686**	11,139
Investments in Subsidiaries	**1,463,998**	1,184,564
Notes Receivable from Subsidiaries	**78,900**	78,900
Deferred Income Taxes	**64,802**	29,619
Other Assets	**43,779**	44,749
Total Assets	**$ 1,775,165**	$ 1,348,971
Liabilities and Stockholders' Equity		
Current Liabilities		
Short-Term Debt	**$ —**	$ 22,637
Accounts Payable to Subsidiaries	**7**	181
Notes Payable to Subsidiaries	**420,363**	190,204
Other	**15,994**	14,526
Total Current Liabilities	**436,364**	227,548
Other Noncurrent Liabilities	**41,686**	50,900
Commitments and Contingencies		
Capitalization		
Long-Term Debt, Net of Current Maturities	**79,798**	79,746
Common Stockholders' Equity	**1,217,317**	990,777
Total Capitalization	**1,297,115**	1,070,523
Total Liabilities and Stockholders' Equity	**$ 1,775,165**	$ 1,348,971

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
CONDENSED STATEMENTS OF INCOME

(in thousands)	*Years Ended December 31,* 2022	2021	2020
Income			
Equity Income in Earnings of Subsidiaries	**$ 296,833**	$ 188,375	$ 106,379
Interest Income from Subsidiaries	**3,382**	2,826	2,859
Other Income	**466**	1,290	1,317
Total Income	**300,681**	192,491	110,555
Expense			
Operating Expenses	**17,269**	14,825	14,007
Interest Charges	**4,066**	4,727	4,599
Interest Charges from Subsidiaries	**5**	3	136
Nonservice Cost Components of Postretirement Benefits	**1,023**	1,097	1,150
Total Expense	**22,363**	20,652	19,892
Income Before Income Taxes	**278,318**	171,839	90,663
Income Tax Benefit	**5,866**	4,930	5,188
Net Income	**$ 284,184**	$ 176,769	$ 95,851

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
CONDENSED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
(in thousands)	*2022*	*2021*	*2020*
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	**$ 28,807**	$ 60,695	$ 54,027
Cash Flows from Investing Activities			
Investment in Subsidiaries	**(50,000)**	—	(150,000)
Debt Repaid by Subsidiaries	**—**	169	182
Other, net	**(1,695)**	(884)	(2,419)
Net Cash Used in Investing Activities	**(51,695)**	(715)	(152,237)
Cash Flows from Financing Activities			
Net (Repayments) Borrowings on Short-Term Debt	**(22,637)**	(42,529)	59,166
Borrowings from Subsidiaries	**236,926**	49,085	44,741
Proceeds from Issuance of Common Stock	**—**	696	52,432
Payments for Shares Withheld for Employee Tax Obligations	**(2,942)**	(1,507)	(2,069)
Payments for Retirement of Long-Term Debt	**—**	(169)	(182)
Dividends Paid	**(68,755)**	(64,864)	(60,314)
Other, net	**(461)**	(689)	(523)
Net Cash Provided by (Used in) Financing Activities	**142,131**	(59,977)	93,251
Net Change in Cash and Cash Equivalents	**119,243**	3	(4,959)
Cash and Cash Equivalents at Beginning of Period	**3**	—	4,959
Cash and Cash Equivalents at End of Period	**$ 119,246**	$ 3	$ —

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by Reference

OTC's consolidated statements of comprehensive income and common shareholders' equity in Part II, Item 8 are incorporated by reference.

Basis of Presentation

The condensed financial information of OTC is presented to comply with Rule 12-04 of Regulation S-X. The unconsolidated condensed financial statements do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read with the consolidated financial statements and related notes included in this report on Form 10-K.

OTC'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 income in earnings of subsidiaries.

Related Party Transactions

Outstanding receivables from and payables to OTC's subsidiaries as of December 31, 2022 and 2021 are as follows:

(in thousands)	*Accounts Receivable*	*Interest Receivable*	*Current Notes Receivable*	*Long-Term Notes Receivable*	*Accounts Payable*	*Current Notes Payable*
December 31, 2022						
Otter Tail Power Company	**$ 3,016**	**$ —**	**$ —**	**$ —**	**$ 7**	**$ —**
Northern Pipe Products, Inc.	**—**	**7**	**—**	**5,000**	**—**	**77,182**
Vinyltech Corporation	**—**	**18**	**—**	**11,500**	**—**	**90,425**
BTD Manufacturing, Inc.	**—**	**77**	**—**	**52,000**	**—**	**693**
T.O. Plastics, Inc.	**20**	**15**	**—**	**10,400**	**—**	**5,855**
Varistar Corporation	**—**	**—**	**—**	**—**	**—**	**246,208**
Otter Tail Assurance Limited	**242**	**—**	**—**	**—**	**—**	**—**
	$ 3,278	**$ 117**	**$ —**	**$ 78,900**	**$ 7**	**$ 420,363**
December 31, 2021						
Otter Tail Power Company	$ 2,503	$ —	$ —	$ —	$ 7	$ —
Northern Pipe Products, Inc.	—	7	—	5,000	4	32,057
Vinyltech Corporation	13	18	—	11,500	—	34,881
BTD Manufacturing, Inc.	—	77	6,767	52,000	170	—
T.O. Plastics, Inc.	20	15	—	10,400	—	5,995
Varistar Corporation	—	—	—	—	—	117,271
Otter Tail Assurance Limited	281	—	—	—	—	—
	$ 2,817	$ 117	$ 6,767	$ 78,900	$ 181	$ 190,204

Dividends

Dividends paid to OTC (the Parent) from its subsidiaries were as follows:

(in thousands)	***2022***	***2021***	***2020***
Cash Dividends Paid to Parent by Subsidiaries	**$ 68,680**	$ 64,790	$ 55,614

See OTC's notes to consolidated financial statements in Part II, Item 8 for other disclosures.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
OTTER TAIL CORPORATION

Below is a summary of activity within valuation and qualifying accounts for the years ended December 31, 2022, 2021 and 2020:

(in thousands)	*Balance, January 1*	*Charged to Cost and Expenses*	*Deductions [1, 2]*	*Balance, December 31*
Allowance for Credit Losses				
2022	$ 1,836	$ 909	$ (1,097)	$ 1,648
2021	3,215	93	(1,472)	1,836
2020	1,339	3,138	(1,262)	3,215
Deferred Tax Asset Valuation Allowance				
2022	$ —	$ —	$ —	$ —
2021	800	—	(800)	—
2020	800	—	—	800

[1]*Amounts under Allowance for Credit Losses reflect deductions to the allowance for amounts written-off, net of recoveries.*

[2]*Amounts under Deferred Tax Asset Valuation Allowance reflect a release of a valuation allowance based on current expectations of the realizability of the associated deferred tax asset.*

3. Exhibits

The following Exhibits are filed as part of, or incorporated by reference into, this report.

No.	Description
3.1	Third Restated Articles of Incorporation, dated April 12, 2021.
3.2	Restated Bylaws, dated April 12, 2021.
4.1	Description of Securities
10.1.0	Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
10.1.1	First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
10.1.2	Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
10.1.3	Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
10.2	Note Purchase Agreement dated as of August 14, 2013 between Otter Tail Power Company and the Purchasers named therein.
10.3	Note Purchase Agreement dated as of September 23, 2016 between Otter Tail Corporation and the Purchasers named therein.
10.4	Note Purchase Agreement dated as of November 14, 2017 between Otter Tail Power Company and the Purchasers named therein.
10.5	Note Purchase Agreement dated as of September 12, 2019 between Otter Tail Power Company and the Purchasers named therein.
10.6	Note Purchase Agreement dated as of June 10, 2021 between Otter Tail Power Company and the Purchasers named therein.
10.7	Fifth Amended and Restated Credit Agreement, dated as of October 31, 2022, by and between Otter Tail Corporation, as Borrower, and the banks named therein, with U.S. Bank National Association, as Administrative Agent.
10.8	Fourth Amended and Restated Credit Agreement, dated as of October 31, 2022, by and between Otter Tail Power Company, as Borrower, and the banks named therein, with U.S. Bank Nation Association, as Administration Agent.
10.9.0	Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970). Previously filed as Exhibit 10-F in Form 10-K for the year ended December 31, 1989.
10.9.1	Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984). Previously filed as Exhibit 10-F-1 in Form 10-K for the year ended December 31, 1989.
10.9.2	Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983). Previously filed as Exhibit 10-F-2 in Form 10-K for the year ended December 31, 1991.
10.9.3	Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985). Previously filed as Exhibit 10-F-3 in Form 10-K for the year ended December 31, 1991.
10.9.4	Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986). Previously filed as Exhibit 10-F-4 in Form 10-K for the year ended December 31, 1991.
10.9.5	Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10.9.6	Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant. Previously filed as Exhibit 10-F-5 in Form 10-K for the year ended December 31, 1992.
10.10	Big Stone South–Ellendale Project Ownership Agreement dated as of June 12, 2015 between Otter Tail Power Company, a wholly owned subsidiary of Otter Tail Corporation, and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.**
10.11.0	Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company and Minnesota Power & Light Company (dated as of July 1, 1977). Previously filed as Exhibit 5-H in filing 2-61043.
10.11.1	Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1. Previously filed as Exhibit 10-H-1 in Form 10-K for the year ended December 31, 1989.
10.11.2	Supplemental Agreement No. Two, dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement. Previously filed as Exhibit 10-H-2 in Form 10-K for the year ended December 31, 1989.
10.11.3	Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1. Previously filed as Exhibit 10-H-3 in Form 10-K for the year ended December 31, 1989.
10.11.4	Agreement, dated as of September 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No. 1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978. Previously filed as Exhibit 10-H-4 in Form 10-K for the year ended December 31, 1992.
10.11.5	Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10.11.6	Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10.12.0	Lignite Sales Agreement between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., Northwestern Corporation, dated as of October 10, 2012.**
10.12.1	First Amendment to Lignite Sales Agreement dated as of January 30, 2014 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.
10.12.2	Second Amendment to Lignite Sales Agreement dated as of March 16, 2015 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.
10.13	Wind Energy Purchase Agreement dated May 9, 2013 between Otter Tail Power Company and Ashtabula Wind III, LLC.**

No.	Description
10.14.0	Deferred Compensation Plan for Directors (2003 Restatement).*
10.14.1	First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as Amended.*
10.14.2	Second Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as Amended.*
10.15	Executive Survivor and Supplemental Retirement Plan (2020 Restatement).*
10.16	Nonqualified Retirement Plan (2011 Restatement).*
10.17	1999 Employee Stock Purchase Plan, As Amended (2016).
10.18	1999 Stock Incentive Plan, As Amended (2006).*
10.19	2014 Executive Annual Incentive Plan.*
10.20	Otter Tail Corporation 2014 Stock Incentive Plan.*
10.21	Form of 2015 Restricted Stock Unit Award Agreement (Executives).*
10.22	Form of 2015 Restricted Stock Unit Award Agreement (Legacy).*
10.23	Form of 2015 Restricted Stock Award Agreement for Directors.*
10.24	Otter Tail Corporation Executive Restoration Plus Plan, 2020 Restatement.*
10.25	Form of 2018 Performance Award Agreement (Executives).*
10.26	Form of 2018 Performance Award Agreement (Legacy).*
10.27	Form of 2018 Restricted Stock Award Agreement for Directors.*
10.28	Summary of Non-Employee Director Compensation (2022).*
10.29	Executive Employment Agreement, Kevin Moug, as Amended [effective January 1, 2013].*
10.30	Change in Control Severance Agreement, Kevin G. Moug, dated July 1, 2009.*
10.31	Change in Control Severance Agreement, Chuck MacFarlane, dated February 24, 2012.*
10.32	Change in Control Severance Agreement, Timothy Rogelstad, dated April 14, 2014.*
10.33	Change in Control Severance Agreement, Paul Knutson, dated December 17, 2012.*
10.34	Change in Control Severance Agreement, John Abbott, dated April 13, 2015.*
10.35	Change in Control Severance Agreement, Jennifer Smestad, dated January 1, 2018.*
10.36	Form of Change in Control Severance Agreement (2023)*
10.37	Otter Tail Corporation Executive Severance Plan (2015).*
21	Subsidiaries of Registrant.
23	Consent of Deloitte & Touche LLP.
24	Power of Attorney.
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

**Management contract, compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.*

***Confidential information has been omitted from this Exhibit and filed separately with the Securities and Exchange Commission pursuant to a confidential treatment request under Rule 24b-2.*

The Company hereby undertakes to furnish copies of any of the omitted schedules and exhibits to the Securities and Exchange Commission upon request.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

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 report to be signed on its behalf by the undersigned, thereunto duly authorized.

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Senior Vice President
(authorized officer and principal financial officer)

Dated: February 15, 2023

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 and on the dates indicated:

Signature and Title

Charles S. MacFarlane President and Chief Executive Officer (principal executive officer) and Director	)	
Kevin G. Moug Chief Financial Officer and Senior Vice President (principal financial and accounting officer)	)	By /s/ Charles S. MacFarlane
Nathan I. Partain Chairman of the Board and Director	)	Charles S. MacFarlane Pro Se and Attorney-in-Fact Dated: February 15, 2023
Karen M. Bohn, Director	)	
John D. Erickson, Director	)	
Steven L. Fritze, Director	)	
Kathryn O. Johnson, Director	)	
Michael E. LeBeau, Director	)	
James B. Stake, Director	)	
Thomas J. Webb, Director	)	

Jeanne H. Crain, Director**

Mary E. Ludford, Director**

**Director was appointed to the Otter Tail Corporation Board of Directors effective, January 1, 2023, and has not signed the Annual Report on Form 10-K herein.

SHAREHOLDER SERVICES

OTTER TAIL CORPORATION STOCK LISTING

Otter Tail Corporation common stock trades on the Nasdaq Global Select Market. Our ticker symbol is OTTR. You can find our daily stock price on our website, www.ottertail.com. Shareholders who sign up for online account access can view their account information online.

DIVIDENDS

Otter Tail Corporation has paid dividends on our common shares each quarter since 1938 without interruption or reduction. 2022 dividends were $1.65 per share, and the year-end dividend yield was 2.8 percent. Total shareholder return grew at a compounded average annual rate of 12.7 percent over the past ten years.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Our Dividend Reinvestment and Share Purchase Plan provides shareowners of record with a convenient method for purchasing shares of Otter Tail Corporation common stock. Approximately 84 percent of eligible shareholders holding approximately 9 percent of our common shares are enrolled. Through this plan, participants may have their dividends automatically reinvested in additional shares without paying any brokerage fees or service charges. Shareholders also may contribute a minimum of $10 and a maximum of $120,000 annually to purchase shares of our common stock. Automatic withdrawal from a checking or savings account is available for this service. Shareholders also may sell shares through the plan. Existing Otter Tail shareholders and new investors can enroll online through shareowneronline.com. For the first purchase, the minimum investment is $250. For more information, contact Shareholder Services.

ELECTRONIC DIVIDEND DEPOSIT

You can arrange for electronic deposit of your dividends directly to your checking or savings accounts. For authorization materials, contact Shareholder Services.

STOCK CERTIFICATES AND DIRECT REGISTRATION SYSTEM (DRS)

Replacing missing certificates is a costly and time-consuming process so you should keep a separate record of the certificate number, purchase date, date of issue, price paid, and exact registration name. If you are enrolled in the Dividend Reinvestment and Share Purchase Plan, you have the option of depositing your common certificates into your plan account. We also offer DRS as a method of holding your shares in book-entry form, which eliminates the need to hold stock certificates.

2023 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 17, 2023 • 10:30 a.m., Central Daylight Time / Meeting Format: Virtual-only

2023 COMMON DIVIDEND DATES

Ex-Dividend	Record	Payment
February 13	February 14	March 10
May 12	May 15	June 9
August 14	August 15	September 8
November 14	November 15	December 8

KEY STATISTICS

Nasdaq	OTTR
Year-end stock price	$58.71
Year-end market-to-book ratio	2.01
Annual dividend yield	2.8%
Shares outstanding (as of December 31, 2022)	41.6 million
Market capitalization (as of December 31, 2022)	$2.4 billion
2022 average daily trading volume	160,876
Institutional holdings (shares as of December 31, 2022)	24.2 million

2022 CREDIT RATINGS

Otter Tail Corporation:	Moody's	Fitch	S&P
Issuer Default Rating	Baa2	BBB-	BBB
Senior Unsecured Debt	n/a	BBB-	n/a
Outlook	Stable	Stable	Stable

Otter Tail Power Company:	Moody's	Fitch	S&P
Issuer Default Rating	A3	BBB	BBB+
Senior Unsecured Debt	n/a	BBB+	BBB+
Outlook	Stable	Stable	Stable

TRANSFER AGENT

Equiniti Shareowner Services
P.O. Box 64856, St. Paul, MN 55164-0856
Phone: 800-468-9716 or 651-450-4064

SHAREHOLDER SERVICES

Otter Tail Corporation	Phone: 800-664-1259
215 South Cascade Street	or 218-739-8479
P.O. Box 496	Email: sharesvc@ottertail.com
Fergus Falls, MN 56538-0596	Fax: 218-998-3165

OTTER TAIL
CORPORATION

SHAREHOLDER SERVICES

215 S. Cascade St., P.O. Box 496
Fergus Falls, MN 56538-0496
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Email: sharesvc@ottertail.com
www.ottertail.com / Nasdaq: OTTR

OTTER TAIL POWER COMPANY **Case No. PU-23-342**
Electric Utility - State of North Dakota **Supplemental Exhibit__(CLP-1), Schedule F-2**
DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR **Financial Information**

Definition: The incremental amount of gross revenue required to generate an additional dollar of operating income. Gross earnings fees included.

Line No.	Description				Test Year 2024 % of Incremental Gross Revenues
1	Federal Income Taxes				20.09%
2	State Income Taxes				4.31%
3	Total Tax Percentage				24.40%
4	Operating Income %	= 100% -	24.40%	=	75.60%
5	Gross Revenue	=	100.00% / 75.60%	=	1.322837