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Fergus Falls, Minnesota 56538-0496
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July 31, 2024

Steve Kahl
Executive Secretary/Director of Administration
North Dakota Public Service Commission
State Capitol - 600 East Boulevard
Bismarck, ND 58505-0480

RE: Otter Tail Power Company's 2023 Annual Report

Dear Mr. Kahl:

Enclosed is Otter Tail Power Company's (Otter Tail's) 2023 Annual Report for North Dakota. As in past years, I am enclosing a copy of Otter Tail Corporation's 2023 Annual Report to Shareholders and SEC Form 10-K for Otter Tail Corporation and Otter Tail's 2023 FERC FORM No. 1. I am also forwarding an electronic copy of the North Dakota Annual Report in .PDF format by email to you at ndpsc@nd.gov.

Pages 1-3 reflect operating statement, rate base, and capital structure values which include Otter Tail's current base rate recoveries as well as recoveries through Otter Tail's renewable, transmission, and generation cost recovery riders on an actual, un-normalized basis. Pages 4-6 reflect the same information on a normalized basis to adjust for the impacts of anomalous items, including weather. Otter Tail's actual 2023 earnings reflected a return on equity (ROE) of 9.24 percent. As shown on page 5 of the attached report, Otter Tail's normalized 2023 results reflected an 8.29 percent ROE.

Additionally enclosed are reports on smart metering, the Trade Secret assessment of the annual impact from the Super Large General Service Tariff Electric Rate Schedule Section 10.06 (SLGS) customer for calendar year 2023 and a Trade Secret report on the Economic Development Rider Rate Schedule Section 14.13 (EDR) for the calendar year 2023. The reports on the SLGS and EDR customers are pursuant to discussions with both the North Dakota Public Service Commission and Commission staff at the time the SLGS tariff was established and approved by the Commission. In accordance with N.D. Admin. Code § 69-02-09-02, an Application for Trade Secret Protection is being provided along with a single copy of the trade secret version of the Application and supporting testimony in a sealed envelope marked **PROTECTED INFORMATION – PRIVATE**.

Mr. Kahl
July 28, 2024
Page 2

If you have questions on the information provided, do not hesitate to contact me at (218) 739-8282 or cbyrnes@otpc.com.

Sincerely,

/s/ CHRIS BYRNES
Chris Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics

vjm
Enclosures
By electronic service and First Class mail

ANNUAL REPORT
OF
OTTER TAIL POWER COMPANY
TO THE
PUBLIC SERVICE COMMISSION OF NORTH DAKOTA
FOR THE
YEAR ENDED DECEMBER 31, 2023

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Otter Tail Power Company
2023 North Dakota Annual Report

Operating Statement - With All Riders, Un-Normalized

	(A)	(B)	(C)	(D)	(E)	
Line No.	2023 Total Company	2023 North Dakota	ND Percent (B / A)	2022 North Dakota	Annual Change (B-D / D)	
	Operating Revenues:					
1	Residential	137,254,803	64,277,169	46.83%	66,972,964	-4.03%
2	Small Commercial and Industrial	99,892,742	50,493,353	50.55%	51,999,326	-2.90%
3	Large Commercial and Industrial	212,321,594	71,815,944	33.82%	68,862,349	4.29%
4	Other Retail	7,529,789	3,195,321	42.44%	3,356,711	-4.81%
5	Total Retail Revenue	456,998,928	189,781,787	41.53%	191,191,350	-0.74%
6	Other Electric Revenue	74,907,477	16,203,943	21.63%	18,158,019	-10.76%
7	Total Revenue	531,906,406	205,985,730	38.73%	209,349,368	-1.61%
	Operating Expenses:					
8	Production Expenses	176,191,347	74,680,891	42.39%	82,768,999	-9.77%
9	Transmission Expenses	36,748,767	13,604,159	37.02%	14,387,811	-5.45%
10	Distribution Expenses	20,135,961	9,017,670	44.78%	7,838,847	15.04%
11	Customer Accounting Expenses	14,668,292	6,459,624	44.04%	6,186,536	4.41%
12	Customer Service and Information Expenses	10,971,526	1,190,260	10.85%	1,168,276	1.88%
13	Sales Expenses	380,951	83,182	21.84%	41,797	99.01%
14	Administration and General Expenses	49,694,670	19,432,122	39.10%	20,082,182	-3.24%
15	Charitable Contributions	0	0	N/A	0	N/A
16	Depreciation Expense	73,281,429	28,654,558	39.10%	26,709,167	7.28%
17	General Taxes	16,604,736	6,053,596	36.46%	6,464,014	-6.35%
18	Total Operating Expenses	398,677,679	159,176,062	39.93%	165,647,629	-3.91%
19	Net Operating Income Before Income Taxes	133,228,727	46,809,668	35.13%	43,701,739	7.11%
	Income Tax Expense:					
20	Investment Tax Credit	(5,974,915)	(2,231,288)	37.34%	(2,295,960)	-2.82%
21	Deferred Income Taxes	15,581,356	5,017,141	32.20%	8,674,492	-42.16%
22	Income Taxes	5,950,409	2,345,029	39.41%	0	100.00%
23	Total Income Tax Expense	15,556,850	5,130,882	32.98%	6,378,532	-19.56%
24	Net Regulated Earnings	117,671,877	41,678,786	35.42%	37,323,207	11.67%

Otter Tail Power Company
2023 North Dakota Annual Report

Rate Base - With All Riders, Un-Normalized

	(A)	(B)	(C)	(D)	(E)	
Line No.	2023 Total Company	2023 North Dakota	ND % (B / A)	2022 North Dakota	Annual Change (B-D / D)	
1	Plant in Service	2,886,262,619	1,084,654,218	37.58%	1,041,850,025	4.11%
2	Net Capitalized Items - Big Stone Plant			0.00%		0.00%
3	Accumulated Depreciation	(998,090,585)	(406,873,524)	40.77%	(391,231,179)	4.00%
4	Net Plant in Service	1,888,172,034	677,780,694	35.90%	650,618,846	4.17%
5	Plant Held for Future Use	12,038	4,698	39.03%	12,897	-63.57%
6	Construction Work in Progress	9,006,430	3,835,086	42.58%	7,674,957	-50.03%
7	Materials and Supplies	36,951,483	15,252,169	41.28%	12,184,922	25.17%
8	Fuel Stocks	11,570,190	4,747,612	41.03%	4,092,023	16.02%
9	Prepayments	57,617,620	20,682,496	35.90%	9,181,902	125.25%
10	Customer Advances	(1,809,207)	(649,435)	35.90%	(572,270)	13.48%
11	Cash Working Capital	2,656,409	2,240,644	84.35%	2,654,567	-15.59%
12	Accumulated Deferred Income Taxes	(283,445,204)	(106,785,515)	37.67%	(128,524,052)	-16.91%
13	Total Average Rate Base	<u>1,720,731,793</u>	<u>617,108,449</u>	35.86%	<u>557,323,792</u>	10.73%
ACTUAL						
14	Rate of Return on Average Rate Base (page 1, Line 24 /line 13)	6.84%	6.75%			
15	Less: Weighted Cost of Ltd (Page 3, line 1 (D))	2.06%	2.06%			
16	Weighted Cost of Pref. Stock (Page 3 line 2 (D))	<u>0.00%</u>	<u>0.00%</u>			
17	Weighted Return on Equity	4.78%	4.70%			
18	% of Equity to Capital Structure (Page 3, line 3 (B))	<u>54.29%</u>	<u>54.29%</u>			
19	Return on Equity (Page 3, line 3 (C))	<u>8.80%</u>	<u>8.65%</u>			

Otter Tail Power Company
2023 North Dakota Annual Report

Average Weighted Cost of Capital - With All Riders, Un-Normalized

		(A)	(B)	(C)	(D)
Line No.	Description	2023 Total	Ratio	Cost	Weighted Cost
1	Long Term Debt	794,477,513	45.71%	4.50%	2.06%
2	Preferred Equity	0	0.00%	0.00%	0.00%
3	Common Equity	943,746,541	54.29%	8.65%	4.70%
4	Total	1,738,224,054	100.00%		6.75%

Otter Tail Power Company
2023 North Dakota Annual Report

Operating Statement - With All Riders, Normalized

	(A)	(B)	(C)	(D)	(E)	
Line No.	2023 Total Company Description	2023 North Dakota	N. D. % (B / A)	2022 North Dakota	Annual Change (B-D / D)	
	Operating Revenues:					
1	Residential	136,022,028	63,262,759	46.51%	64,462,698	-1.86%
2	Small Commercial and Industrial	99,766,161	50,164,073	50.28%	50,176,769	-0.03%
3	Large Commercial and Industrial	212,014,979	71,683,668	33.81%	68,573,006	4.54%
4	Other Retail	7,515,264	3,185,370	42.39%	3,337,009	-4.54%
5	Total Retail Revenue	455,318,431	188,295,871	41.35%	186,549,483	0.94%
6	Other Electric Revenue	69,357,036	16,203,943	23.36%	18,158,019	-10.76%
7	Total Revenue	524,675,468	204,499,814	38.98%	204,707,501	-0.10%
	Operating Expenses:					
8	Production Expenses	176,383,895	74,764,271	42.39%	80,952,165	-7.64%
9	Transmission Expenses	36,748,767	13,604,159	37.02%	14,387,811	-5.45%
10	Distribution Expenses	20,135,961	9,017,670	44.78%	7,838,847	15.04%
11	Customer Accounting Expenses	14,668,292	6,459,624	44.04%	6,186,536	4.41%
12	Customer Service and Information Expenses	10,971,526	1,190,260	10.85%	1,168,276	1.88%
13	Sales Expenses	380,951	83,182	21.84%	41,797	99.01%
14	Administration and General Expenses	49,694,670	19,432,122	39.10%	20,082,182	-3.24%
15	Charitable Contributions	0	0	N/A	0	N/A
16	Depreciation Expense	73,281,429	28,654,558	39.10%	26,709,167	7.28%
17	General Taxes	16,604,736	6,053,596	36.46%	6,464,014	-6.35%
18	Total Operating Expenses	398,870,227	159,259,442	39.93%	163,830,794	-2.79%
19	Net Operating Income Before Income Taxes	125,805,241	45,240,372	35.96%	40,876,707	10.68%
	Income Tax Expense:					
20	Investment Tax Credit	(5,974,915)	(2,231,288)	37.34%	(2,295,960)	-2.82%
21	Deferred Income Taxes	15,581,356	5,017,141	32.20%	7,985,656	-37.17%
22	Income Taxes	5,518,732	1,961,365	35.54%	0	100.00%
23	Total Income Tax Expense	15,125,173	4,747,218	31.39%	5,689,696	-16.56%
24	Net Regulated Earnings	110,680,068	40,493,154	36.59%	35,187,011	15.08%

Otter Tail Power Company
2023 North Dakota Annual Report

Rate Base - With All Riders, Normalized

	(A)	(B)	(C)	(D)	(E)	
Line No.	2023 Total Company	2023 North Dakota	N. D. % (B / A)	2022 North Dakota	Annual Change (B-D / D)	
1	Plant in Service	2,886,262,619	1,084,654,218	37.58%	1,041,850,025	4.11%
2	Net Capitalized Items - Big Stone Plant			0.00%		0.00%
3	Accumulated Depreciation	<u>(998,090,585)</u>	<u>(406,873,524)</u>	40.77%	<u>(391,231,179)</u>	4.00%
4	Net Plant in Service	1,888,172,034	677,780,694	35.90%	650,618,846	4.17%
5	Plant Held for Future Use	12,038	4,698	39.03%	12,897	-63.57%
6	Construction Work in Progress	9,006,430	3,835,086	42.58%	7,674,957	-50.03%
7	Materials and Supplies	36,951,483	15,252,169	41.28%	12,184,922	25.17%
8	Fuel Stocks	11,570,190	4,747,612	41.03%	4,092,023	16.02%
9	Prepayments	57,617,620	20,682,496	35.90%	9,181,902	125.25%
10	Customer Advances	<u>(1,809,207)</u>	<u>(649,435)</u>	35.90%	<u>(572,270)</u>	13.48%
11	Cash Working Capital	2,805,364	2,375,299	84.67%	2,530,836	-6.15%
12	Accumulated Deferred Income Taxes	<u>(283,445,204)</u>	<u>(106,785,515)</u>	37.67%	<u>(128,524,052)</u>	-16.91%
13	Total Average Rate Base	<u>1,720,880,748</u>	<u>617,243,104</u>	35.87%	<u>557,200,061</u>	10.78%
ACTUAL						
14	Rate of Return on Average Rate Base (page 4, Line 24 /line 13)	6.43%	6.56%			
15	Less: Weighted Cost of Ltd (Page 6, line 1 (D))	2.06%	2.06%			
16	Weighted Cost of Pref. Stock (Page 6 line 2 (D))	<u>0.00%</u>	<u>0.00%</u>			
17	Weighted Return on Equity	4.37%	4.50%			
18	% of Equity to Capital Structure (Page 6, line 3 (B))	<u>54.29%</u>	<u>54.29%</u>			
19	Return on Equity (Page 6, line 3 (C))	<u>8.05%</u>	<u>8.29%</u>			

Otter Tail Power Company
2023 North Dakota Annual Report

Average Weighted Cost of Capital - With All Riders, Normalized

		(A)	(B)	(C)	(D)
Line No.	Description	2023 Total	Ratio	Cost	Weighted Cost
1	Long Term Debt	794,477,513	45.71%	4.50%	2.06%
2	Preferred Equity	0	0.00%	0.00%	0.00%
3	Common Equity	943,746,541	54.29%	8.29%	4.50%
4	Total	1,738,224,054	100.00%		6.56%

Otter Tail Power Company
2023 North Dakota Annual Report

Miscellaneous

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line No.	Total Description	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
	Customer Related (ND):										
	Year End # of Customers (1)										
1	Residential	45,431	45,535	45,584	45,614	45,620	45,862	45,882	45,743	45,689	45,379
2	Commercial	12,481	12,448	12,481	12,430	12,395	11,465	11,439	11,385	11,333	11,286
3	Industrial	289	285	283	278	277	980	979	978	984	947
4	Other	882	885	888	890	889	497	499	503	509	504
5	Total Customers	59,083	59,153	59,236	59,212	59,181	58,804	58,799	58,609	58,515	58,116
	KWH's Sold										
6	Residential	606,546,947	628,366,462	582,626,650	602,784,894	629,175,343	630,555,383	591,880,809	580,345,390	609,253,548	669,563,374
7	Commercial	512,686,586	518,102,686	470,598,314	511,173,319	517,757,884	309,037,831	300,470,972	291,700,647	296,940,142	339,108,033
8	Industrial	1,365,347,468	1,122,524,727	607,703,011	596,367,789	653,782,339	861,510,082	854,040,398	856,544,193	852,769,327	899,948,129
9	Other	25,335,667	27,194,689	26,994,553	29,522,372	29,278,133	29,467,197	29,625,196	29,262,956	29,829,127	30,127,525
10	Subtotal	2,509,916,669	2,296,188,564	1,687,922,528	1,739,848,374	1,829,993,699	1,830,570,493	1,776,017,375	1,757,853,186	1,788,792,144	1,938,747,061
11	Unbilled sales	(28,187,360)	21,527,683	4,732,945	(1,967,352)	(9,672,097)	3,250,372	11,845,290	5,681,679	(9,116,877)	(5,251,688)
12	Total kWh	2,481,729,309	2,317,716,247	1,692,655,473	1,737,881,022	1,820,321,602	1,833,820,865	1,787,862,665	1,763,534,865	1,779,675,267	1,933,495,373
	System Wide Reliability Indices										
13	SAIDI (total minutes)	110.8	118.6	79.0	91.3	128.2	85.3	86.5	110.5	100.6	74.2
14	SAIFI (frequency)	1.5	1.6	1.2	1.3	1.5	1.3	1.4	1.7	1.7	1.2
15	CAIDI (duration)	75.4	73.2	66.89	69.1	88.7	64.9	61.5	65.7	58.4	59.9

(1) Otter Tail implemented its new customer information system in February 2019. During this conversion, total customer counts by class were updated resulting in the change from 2018 to 2019.

**BEFORE THE
NORTH DAKOTA PUBLIC SERVICE
COMMISSION**

Case No. PU-24-213

**Otter Tail Power Company's
Report on Status of Smart Metering
and Smart Grid Technologies**

July 31, 2024

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Otter Tail Power Company 2023 Annual Report to North Dakota

Report on Status of Smart Metering

In its Order dated August 8, 2007, Case No. PU-06-290, the North Dakota Public Service Commission, at ordering paragraph no. 2, required that:

"Each jurisdictional electric utility shall include in its annual reports to the Commission, beginning with reports filed for 2007, a discussion of progress towards the feasibility of making smart metering available for all customers."

References to smart grid and smart metering have been used interchangeably as the utility industry moves to adopt changes that make sense for each of the utilities' service areas. We've used technology to improve employee productivity and customer service for many years. Smart grid investments occur in many aspects of our work and our mission, which is:

To produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the area in which we do business.

The following lists some of the smart grid-type applications that we discussed in past filings and are still in place today. However, this filing does not go into detail for each of these areas:

- Peak-shaving technologies
- Energy storage systems
- Time-varying rates
- Electricity metering
- Power Profiler
- Bill Analyzer
- Interruption Monitoring System
- Customer Information System

This update focuses on updates to our:

- Customer Experience Platform
- Advanced Metering Infrastructure
- Demand Response
- Outage Management System

In addition, we provide high-level information related to technologies that encompass smart metering in our Innovation 2030 (I2030) initiative.

Customer Experience Platform (CEP)

Otter Tail Power continues to remain focused on providing the best possible experience for our customers. As part of this effort, we have contracted with Accelerated Innovations to develop an online platform that will provide customers enhanced functionality in the areas of bill payment, usage information, and outage communications. A preference center allows customers to choose the communications they want to receive and the method by which they would like to receive them. A mobile application allows customers to access account information on the go. This platform is expected to fully integrate with our Outage Management System, Customer Information System, Paymentus payment provider portal, as well as MDM/AMI and provides the most comprehensive information to the customer when these other systems are in place.

Implementation began in April 2022 and the project went live in August 2023. This platform continues to be evaluated for further improvements to enhance the customer experience.

Advanced Metering Infrastructure (AMI)

Otter Tail Power continues to move forward with our AMI project as part of our Smart Grid initiative. The original implementation plan for the AMI project anticipated business process development, system integration, and initial deployment from late 2021 to the fourth quarter of 2022, with full deployment from late 2022 to the third quarter 2024. The deployment schedule has been delayed due to the integration requirements of the software systems. The AMI pilot of 500 meters occurred in December 2023. Full meter deployment started in mid-February 2024 and will continue throughout the year. While it is anticipated that most AMI meters will be installed by the end of 2024, there will be some AMI meter installations occurring in the first quarter of 2025. Allegiant Utility Services, Otter Tail's meter installation contractor, plans to complete the contracted portion of the installations in 2024, which represents approximately 91 percent of the total meter installations. The remaining meters, which represent meters associated with complex rates, complexity of metering configurations, and heightened impact to customer processes will be installed by Otter Tail employees. Allowing Otter Tail staff to manage these meter exchanges will reduce delays for Allegiant Utility Services and allow for a more coordinated exchange process for the customer group, which includes larger commercial and industrial load.

Demand Response (DR)

The DR Replacement project began development in early 2021. In the Fall of 2021, Otter Tail retained Katama Technologies as a consultant. The Company and the consultant attended industry conferences, during which meetings with top vendors of DR programs were scheduled and their products reviewed. Investigation continued through interviews with nine utilities of interest from across the United States.

Otter Tail's complete Request for Proposals was released in the Fall of 2022. Six responses were received from major vendors in the DR industry. After a rigorous and extensive evaluation, two strategic partners were selected: Landis+Gyr (L+G) and Open Access Technology International (OATI).

Otter Tail expects DR implementation to begin in the fourth quarter of 2024. The project is projected to be completed in 2027.

Otter Tail was also invited to submit a full application for grant opportunities related to the 2021 Infrastructure Investment and Jobs Act. An award through this act would reduce overall project costs. An application was submitted by the deadline and Otter Tail awaits the final decision.

Outage Management System (OMS)

Otter Tail's OMS offers many operational and customer benefits related to outage response as well as a foundation that will be beneficial in future grid modernization plans. The OMS allows Otter Tail to identify outages more rapidly and deploy crews more efficiently to reduce the number and length of outages. It also allows Otter Tail to better communicate with customers before, during, and after outage events, by sending outage notifications, updates on estimated time of restoration, and restoration notices. Outage notifications were enhanced with the implementation of the Customer Experience Portal (CEP) in August 2023 and for those customers who have signed up to receive additional notifications. OMS system modeling improvements, as part of the GIS portion of the project, were completed in May 2024 and will improve outage and restoration information and communications to our customers.

Once the AMI implementation is complete, the speed in which the OMS receives outage information will be enhanced, improving restoration times even further. The individual meters will provide power-off and power-on notifications to be utilized by the OMS.

Otter Tail is currently working with the vendors as part of the AMI project to complete the necessary integrations and anticipates completion by late 2024 or early 2025.

Innovation 2030 Initiative (I2030)

As part of our Smart Grid initiatives, our I2030 Portfolio includes projects that support our objectives of increased customer engagement, increased safety and reliability, and increased business efficiency through technology and process opportunities. Each of the prior discussed projects are part of the larger I2030 program. I2030, a company initiative that began in 2016, continues in the planning, development, and execution stages of several technologies. In addition to the prior projects discussed, the Company has completed the deployment of a new Staking system, Enterprise Service Bus, and Financial Information System.. Another area under consideration as part of I2030 is a Work Management System. We continue to review our evaluation and business case justifications for all projects within the portfolio.

2023



Annual Report





ELECTRIC PLATFORM

Otter Tail Power Company

Electric utility
Headquarters: Fergus Falls, MN
Founded 1907
President, Tim Rogelstad
790 full-time employees
www.otpc.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

MANUFACTURING PLATFORM

BTD Manufacturing, Inc.

Metal fabricator
Headquarters: Detroit Lakes, MN
Acquired 1995
President, Paul Gintner
1,458 full-time employees
www.btdmfg.com



T.O. Plastics, Inc.

Custom plastic parts manufacturer
Headquarters: Clearwater, MN
Acquired 2001
President, Paul Meschke
192 full-time employees
www.toplastics.com



Northern Pipe Products, Inc.

PVC pipe manufacturer
Headquarters: Fargo, ND
Acquired 1995
President, Terry Mitzel
98 full-time employees
www.northernpipe.com



Vinyltech Corporation

PVC pipe manufacturer
Headquarters: Phoenix, AZ
Acquired 2000
President, Terry Mitzel
80 full-time employees
www.vtpipe.com



	2023	2022	PERCENT CHANGE
CONSOLIDATED OPERATIONS (\$ in thousands, except per share amounts)			
Operating Revenues	\$ 1,349,166	\$ 1,460,209	(7.6)
Net Income	\$ 294,191	\$ 284,184	3.5
Diluted Earnings per Share	\$ 7.00	\$ 6.78	3.2
Dividends per Common Share	\$ 1.75	\$ 1.65	6.1
Return on Average Common Equity	22.1%	25.6%	(13.6)
Book Value per Common Share	\$ 34.60	\$ 29.24	18.3
Cash Flow from Operating Activities	\$ 404,499	\$ 389,309	3.9
Number of Common Shares Outstanding	41,710,521	41,631,113	0.2
Number of Common Shareholders	10,650	11,748	(9.3)
Closing Stock Price	\$ 84.97	\$ 58.71	44.7
Total Return (share price appreciation plus dividends)	47.7%	(15.5)%	n/m
Total Market Value of Common Stock	\$ 3,544,143	\$ 2,444,163	45.0
ELECTRIC PLATFORM (\$ in thousands)			
Operating Revenues	\$ 528,359	\$ 549,699	(3.9)
Total Retail Electric Sales (MWH)	5,772,215	5,592,368	3.2
Operating Income	\$ 106,521	\$ 113,138	(5.8)
Net Income	\$ 84,424	\$ 79,974	5.6
Customers	133,747	133,414	0.2
Total Assets	\$ 2,533,831	\$ 2,351,961	7.7
Capital Expenditures	\$ 240,695	\$ 147,869	62.8
MANUFACTURING PLATFORM (\$ in thousands)			
Operating Revenues	\$ 820,807	\$ 910,510	(9.9)
Operating Income	\$ 283,542	\$ 293,643	(3.4)
Net Income	\$ 209,202	\$ 216,324	(3.3)
Total Assets	\$ 415,522	\$ 372,187	11.6
Capital Expenditures	\$ 46,313	\$ 23,199	99.6

To our shareholders

CHARLES S. MACFARLANE
PRESIDENT AND CEO



Otter Tail Corporation and its companies continue to build strong electric utility and manufacturing platforms. Our 2023 financial results reflect the organization's overall health and demonstrate commitment to our mission of delivering value for our shareholders, customers, and employees.

Thank you to our employees for the ways in which you implement our values and your commitment to our customers and shareholders. Thank you to our customers and shareholders for your certainty in our ongoing success.

EXCEEDING FINANCIAL PERFORMANCE

Through our companies' combined efforts in 2023, we achieved record financial results. Our diversified business model produced consolidated net income and diluted earnings per share of \$294.2 million and \$7.00 respectively, compared with \$284.2 million and \$6.78 in 2022. Our return on equity in 2023 was 22.1 percent on an equity layer of 61.4 percent.

We have paid dividends on our common stock for 85 years, or 341 consecutive quarters. The dividend yield at December 31, 2023 was 2.0 percent. Our total shareholder return over the five-year period ending December 31, 2023 was 97.1 percent. Our annual indicated dividend per share for 2024 is \$1.87, a 6.9 percent increase over our 2023 dividend rate.

For a third consecutive year, Otter Tail Corporation received the Edison Electric Institute (EEI) Index Award for the top performing small-capitalization utility with a total shareholder return of 83 percent over the five-year period ending September 30, 2023. 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.

Day-to-day operational excellence is the base of our success, and we will continue to build our top-performing companies by focusing on our mission.

DELIVERING ON STRATEGY

ELECTRIC PLATFORM HIGHLIGHTS

Otter Tail Power Company, our regulated electric utility, produced \$84.4 million of earnings in 2023, up 6 percent from 2022. Earnings increased primarily due to higher commercial and industrial sales, lower pension costs, and the recovery of rate base investments. Otter Tail Power grew average rate base by 7.3 percent in 2023, largely through capital investments in renewable energy generation. We continue to make system investments to deliver on customers' expectations, manage operating and maintenance costs, transition to a cleaner energy future, and improve reliability and safety.

In January, we purchased the Ashtabula III Wind Energy Center, located in eastern North Dakota. We had purchased wind-generated electricity from Ashtabula III since 2013 through a power purchase agreement, but owning the facility provides a lower-cost alternative for our customers than maintaining the purchased power arrangement. The 39-turbine site added 62.4 megawatts (MW) of nameplate capacity to our owned generation assets.

We also began plans and received site permits to upgrade and refurbish wind turbines at our Ashtabula, Ashtabula III, Langdon, and Luverne Wind Energy Centers in 2024 and 2025. The costs associated with this project will be offset by tax credits and replacing higher fuel cost generation with zero fuel cost renewables, which is expected to lower customer bills. Once complete, we expect this

wind repowering to provide approximately 164 gigawatt hours of additional energy—the equivalent of a new 40-MW facility.

In August, our 49-MW Hoot Lake Solar facility became fully operational. Hoot Lake Solar was constructed on and near the retired coal-fired Hoot Lake Plant property in Fergus Falls, Minnesota, allowing us the opportunity to utilize existing transmission rights, land, and substation assets. It is the least-cost and third-largest operating solar site based on generation capacity in the state of Minnesota. With the completion of Hoot Lake Solar, nearly 40 percent of our owned and contracted energy generation comes from renewable resources.

We began public outreach and planning in the spring of 2023 for two new 345-kilovolt (kV) transmission lines, which are part of the Midcontinent Independent System Operator (MISO) Long-Range Transmission Planning Tranche 1 projects. We will co-own an approximately 95-mile transmission line between Jamestown and Ellendale, North Dakota, and an approximately 100-mile transmission line between Big Stone, South Dakota, and Alexandria, Minnesota; we are leading development and construction on both. We are also working with the other project owners of the Fargo to Monticello 345-kV transmission line to add a second circuit and additional upgrades to an existing line from Alexandria to a new Big Oaks substation in southeast Minnesota. We estimate our total capital investment in these projects to be approximately \$420 million.

We filed a request to increase our rates with the North Dakota Public Service Commission in November. The request was largely driven by increases in our operating costs over the six years since our last rate case filing. We requested to increase net revenues by approximately \$17 million, or 8.4 percent. Even with this increase, we will continue to have some of the lowest rates in the country.

In December, we submitted an additional supplemental Integrated Resource Plan in Minnesota. Our plan includes the addition of new renewable resources to meet the energy needs of our Minnesota customers. We also requested the authorization to limit the Minnesota share of output of Coyote Station to limited emergency situations, which is expected to reduce the greenhouse gas emissions of the facility while preserving reliability. Finally, we proposed a modified method of resource planning to provide additional flexibility in adding new generation resources that best meet the needs of our customers in each jurisdiction we serve.

Advanced Metering Infrastructure is a technology upgrade that lays the groundwork for us to better meet customers' needs for reliable service while reducing costs. When combined with systems we have in place today, customers will have more visibility into their energy use (helping them save energy and money) and we will be able to respond to outages faster and more precisely. We began installing advanced meters in late 2023 and plan to finish upgrading approximately 174,000 electric meters by early 2025.

MANUFACTURING PLATFORM HIGHLIGHTS

Northern Pipe Products and Vinyltech, our PVC pipe manufacturing companies that comprise our Plastics Segment, produced \$187.7 million of earnings in 2023, down 4 percent

from the segment's record-setting earnings in 2022. Earnings declined due to a decrease in total sales volumes as customers worked through the inventory they amassed during 2022 defensive buying efforts. Despite the slight decrease in earnings, the Plastics Segment employees continue to capitalize on favorable industry conditions and produce strong financial results compared to historic levels.

In 2022, we commenced work on a facility expansion and site improvement plan at our Vinyltech facility in Phoenix, Arizona. This project will provide organic growth opportunities for our business, including adding increased raw material storage and handling capabilities, as well as additional manufacturing capacity at this location. We expect to bring the additional capacity online in the second half of 2024.

Our Manufacturing Segment, which is comprised of BTD Manufacturing, our contract metal fabricator, and T.O. Plastics, our plastics thermoforming manufacturer, produced \$21.5 million of earnings in 2023, a modest increase from 2022.

BTD Manufacturing sales volumes increased in 2023 compared to 2022 as existing customers continue to look to us for additional work and to add value. We added, in a challenging labor market, approximately 200 new employees in 2023 in response to customer demand. We have now shifted our focus from hiring to retaining and training so we are best able to serve our customers going forward. We also commenced an expansion project at our Dawsonville, Georgia, facility and expect to bring the additional capacity online in the first quarter of 2025. This expansion project will help us to better serve our customers and will allow for organic growth opportunities in our Southeast market.

T.O. Plastics sales volumes of horticulture products decreased in 2023 as lead times for these products began to normalize after unique supply-and-demand dynamics experienced last year. As a result, customers are reducing their inventory levels and returning to normal seasonal buying patterns. T.O. Plastics focused on operational and facility improvements in 2023 to expand and optimize manufacturing capacity to better serve our customers and strive for commercial excellence.

A significant reduction in our corporate costs also drove 2023 earnings as we benefited from returns earned on our short-term investments funded by the significant cash flows our businesses—and more specifically, our manufacturing platform—have generated over the last three years.

TARGETING GROWTH

Our long-term focus has not changed. We will continue to grow our businesses and strive for operational, commercial, and talent excellence—strengthening our position in the markets we serve. It is a responsibility we do not take for granted.

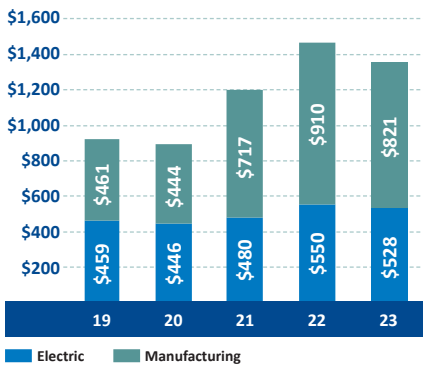
Thank you, again, to our employees for your incredible work and to our customers and shareholders for your confidence in Otter Tail Corporation and our companies.



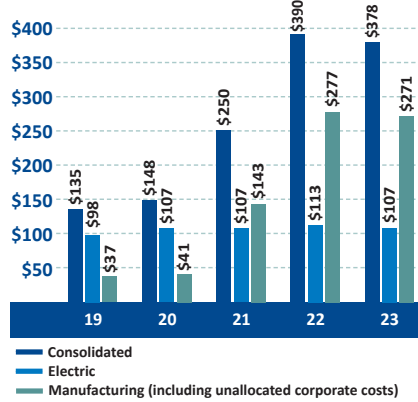
Charles S. MacFarlane
President and Chief Executive Officer



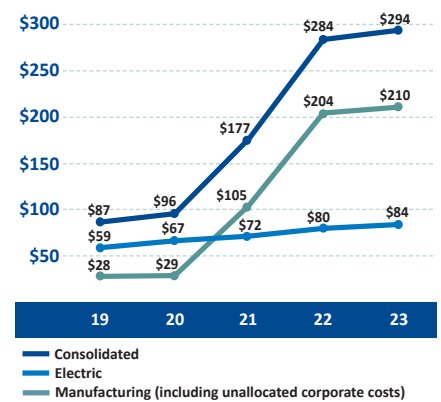
Revenue by platform (millions)



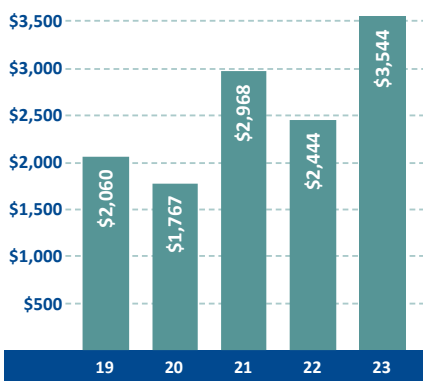
Operating income by platform (millions)



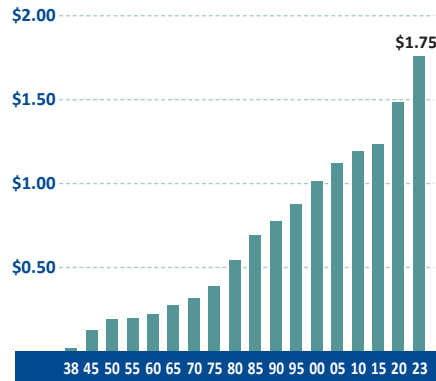
Net income by platform (millions)



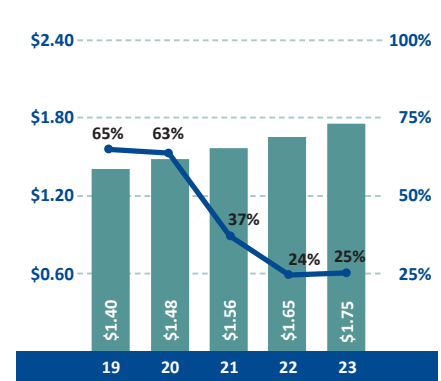
Market capitalization (millions)



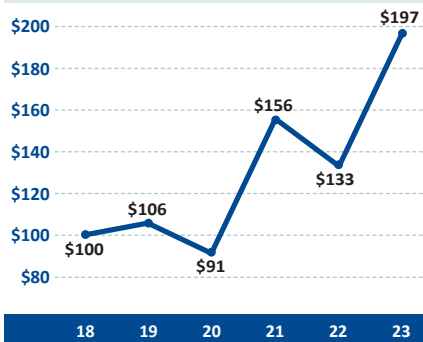
Dividend payment history



Dividend payout ratio



Growth of \$100 investment in Otter Tail Common Stock made December 31, 2018 (with dividends reinvested)



Total shareholder return has grown at a compounded annual rate of 14.5 percent over the past five years. We have paid dividends on common stock for 85 consecutive years.

Selected Common Share Data	2023	2022	2021	2020	2019	2018
Market Price:						
High	\$ 92.74	\$ 82.46	\$ 71.71	\$ 56.90	\$ 57.74	\$ 51.88
Low	\$ 57.29	\$ 52.60	\$ 39.35	\$ 30.95	\$ 45.94	\$ 39.00
Common Price/Earnings Ratio:						
High	13.2	12.2	17.0	24.3	26.6	25.2
Low	8.2	7.8	9.3	13.2	21.2	18.9
Book Value Per Common Share	\$ 34.60	\$ 29.24	\$ 23.84	\$ 21.00	\$ 19.46	\$ 18.38
Selected Data and Ratios	2023	2022	2021	2020	2019	2018
Interest Coverage Before Taxes	8.4x	10.8x	6.5x	4.1x	4.1x	4.0x
Effective Income Tax Rate (percent)	19	21	17	17	17	15
Return on Capitalization Including Short-Term Debt (percent)	10.9	15.6	11.6	7.6	8.0	8.4
Return on Average Common Equity (percent) ¹	22.1	25.6	19.2	11.6	11.6	11.5
Dividend Payout Ratio (percent)	25	24	37	63	65	65
Cash Realization ²	1.37	1.37	1.31	2.21	2.13	1.74
Capital Ratio (percent):						
Short Term and Long-Term Debt	38.6	40.6	46.3	49.3	47.1	45.5
Common Equity	61.4	59.4	53.7	50.7	52.9	54.5
	100.0	100.0	100.0	100.0	100.0	100.0
Selected Electric Operating Data	2023	2022	2021	2020	2019	2018
Revenues (thousands)						
Residential	\$ 135,570	\$ 143,888	\$ 135,361	\$ 127,260	\$ 131,988	\$ 125,045
Commercial and Industrial	312,551	318,494	262,408	254,951	267,125	256,331
Other Retail	7,719	7,918	7,715	7,311	7,365	6,875
Total Retail	455,840	470,300	405,484	389,522	406,478	388,251
Sales for Resale	12,459	18,539	17,936	4,857	5,007	7,735
Other Electric	60,060	60,860	56,901	51,751	47,612	54,269
Total Electric	\$ 528,359	\$ 549,699	\$ 480,321	\$ 446,130	\$ 459,097	\$ 450,255
Kilowatt-hours Sold (thousands)						
Residential	1,252,627	1,309,249	1,241,951	1,266,232	1,303,317	1,321,132
Commercial and Industrial	4,450,183	4,224,190	3,489,342	3,446,743	3,598,002	3,590,651
Other	69,404	58,928	58,586	63,712	67,770	65,177
Total Retail	5,772,215	5,592,368	4,789,879	4,776,687	4,969,089	4,976,960
Sales for Resale	351,729	267,184	420,044	236,528	198,569	271,840
Total	6,123,944	5,859,552	5,209,923	5,013,215	5,167,658	5,248,800
Annual Retail Kilowatt-hour Sales Growth (percent)	3.2	16.8	0.3	(3.9)	(0.2)	3.4
Heating Degree Days ³	6,259	7,122	5,794	6,174	7,240	6,904
Cooling Degree Days ⁴	590	531	704	534	392	567
Average Revenue Per Kilowatt-hour						
Residential	10.82¢	10.99¢	10.90¢	10.05¢	10.13¢	9.46¢
Commercial and Industrial	7.02¢	7.54¢	7.52¢	7.40¢	7.42¢	7.14¢
All Retail	7.90¢	8.41¢	8.47¢	8.15¢	8.18¢	7.80¢
Customers						
Residential	104,151	103,950	103,835	103,658	103,328	104,242
Commercial and Industrial	27,709	27,578	27,582	27,468	27,348	27,223
Other	1,887	1,886	1,887	1,906	1,911	993
Total Electric Customers	133,747	133,414	133,304	133,032	132,587	132,458
Peak Demand and Net Generating Capability						
Peak Demand (kilowatts)	961,210	987,628	865,120	844,929	923,962	911,726
Net Generating Capability (kilowatts): ⁵						
Steam	405,300	406,200	406,800	548,100	548,700	548,500
Wind	350,400	288,000	288,000	288,000	138,000	138,000
Combustion Turbines	352,500	343,700	352,500	107,900	105,100	106,200
Solar	49,900	—	—	—	—	—
Hydro	2,600	2,500	2,600	2,500	2,800	2,900
Total Owned Generating Capability	1,160,700	1,040,400	1,049,900	946,500	794,600	795,600

Notes:

(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.

(3) Based on 55 degrees Fahrenheit base and average method.

(4) Based on 65 degrees Fahrenheit base and average method.

(5) Measurement of net dependable capacity.

Executive Leadership

CHARLES S. MACFARLANE

President and Chief Executive Officer

TODD R. WAHLUND

Chief Financial Officer and Vice President

JENNIFER O. SMESTAD

Vice President
General Counsel and Corporate Secretary

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

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)

THOMAS J. WEBB

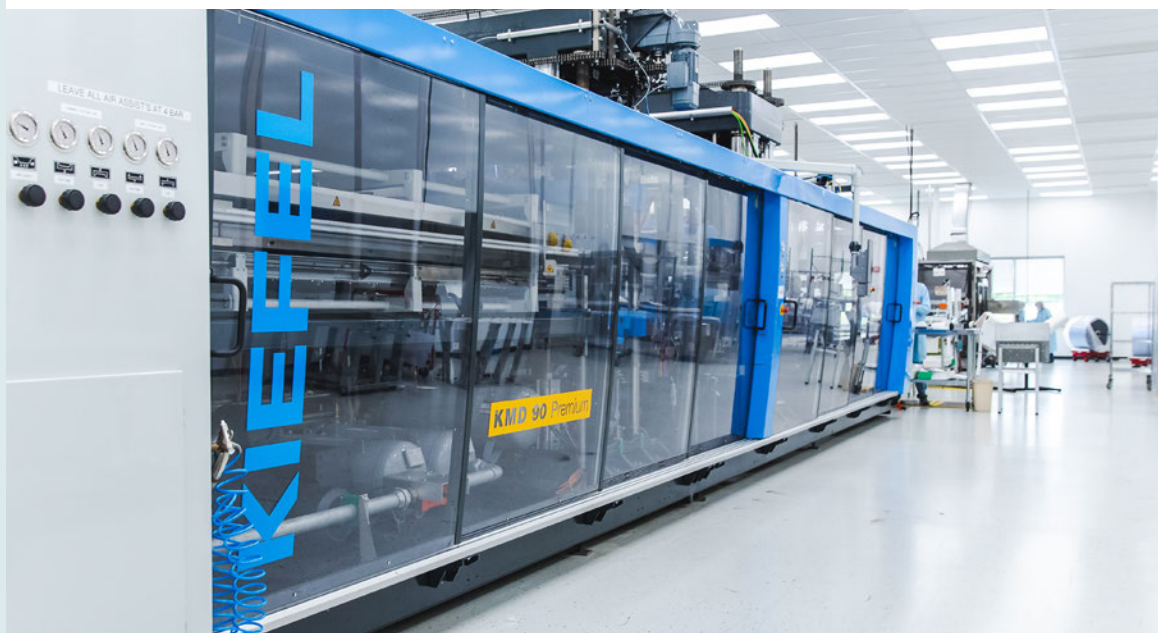
A/C
Richland, Michigan
Advisor, Retired Vice President and Chief Financial Officer
CMS Energy Corporation
(gas and electric utility)

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, 2023 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

(State or other jurisdiction of incorporation or organization)

27-0383995

(I.R.S. Employer Identification No.)

215 South Cascade Street, Box 496, Fergus Falls, Minnesota

(Address of principal executive offices)

56538-0496

(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.

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

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

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

As of June 30, 2023, the aggregate market value of common stock held by non-affiliates was **\$3,646,181,401**.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **41,710,521 Common Shares (\$5 par value) as of January 31, 2024**.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive Proxy Statement for its 2024 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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DEFINITIONS

The following abbreviations or acronyms are used in the text.

AFUDC	Allowance for Funds Used During Construction	kwh	kilowatt-hour
AME	Available Maximum Energy	LSA	Lignite Sales Agreement
ARO	Asset Retirement Obligation	MDT	Metering and Distribution Technology
ARP	Alternative Revenue Program	MISO	Midcontinent Independent System Operator
ASC	Accounting Standards Codification	MW	Megawatt
BTD	BTD Manufacturing, Inc.	MPUC	Minnesota Public Utilities Commission
CCMC	Coyote Creek Mining Company, L.L.C.	NAV	Net Asset Value
CCS	Carbon Capture and Sequestration	NDDEQ	North Dakota Department of Environmental Quality
CDD	Cooling Degree Day	NDPSC	North Dakota Public Service Commission
CIS	Critical Security Controls	NERC	North American Electric Reliability Corporation
CO ₂	Carbon dioxide	Northern Pipe	Northern Pipe Products, Inc.
COSO	Committee of Sponsoring Organizations of the Treadway Commission	OTC	Otter Tail Corporation
ECO	Energy Conservation and Optimization Rider	OTP	Otter Tail Power Company
EEL	Edison Electric Institute	Paris	United Nations Framework Convention on Climate Change Agreement
EEP	Energy Efficiency Plan	PFAS	Polyfluoroalkyl substances
EGU	Electric Generating Unit	PIR	Phase-in Rider
EPA	Environmental Protection Agency	PSLRA	Private Securities Litigation Reform Act of 1995
ERISA	Employee Retirement Income Security Act of 1974	PTCs	Production tax credits
ESSRP	Executive Survivor and Supplemental Retirement Plan	PVC	Polyvinyl chloride
EUIC	Electric Utility Infrastructure Costs Rider	RHR	Regional Haze Rule
FASB	Financial Accounting Standards Board	ROE	Return on equity
FCA	Fuel Clause Adjustment	REC	Renewable Energy Certificate
FERC	Federal Energy Regulatory Commission	RRR	Renewable Resource Rider
FOB	Free on Board	SDPUC	South Dakota Public Utilities Commission
GCR	Generation Cost Recovery Rider	SEC	Securities and Exchange Commission
GHG	Greenhouse Gas	SIP	State implementation plan
HDD	Heating Degree Day	SOFR	Secured Overnight Financing Rate
ICSP	Information and Cybersecurity Program	T.O. Plastics	T.O. Plastics, Inc.
IRP	Integrated Resource Plan	TCR	Transmission Cost Recovery Rider
ITCs	Investment Tax Credits	TSR	Total Shareholder Return
kV	kiloVolt	VIE	Variable Interest Entity
kW	kiloWatt	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," "can," "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. Otter Tail Power (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 engaged 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 and growing earnings stream, support quality credit ratings, and provide for 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. Our long-term financial objectives include achieving a compounded annual growth rate in earnings per share in the range of 5 - 7%, with a long-term earnings mix of approximately 65% from our Electric segment and 35% from our manufacturing platform. We also are targeting an annual increase in our dividend to be in the range of 5 - 7%. We expect our earnings growth and cash flow generation to be driven by rate base investments in our Electric segment and from existing capacities and planned investments within our Manufacturing and Plastics segments.

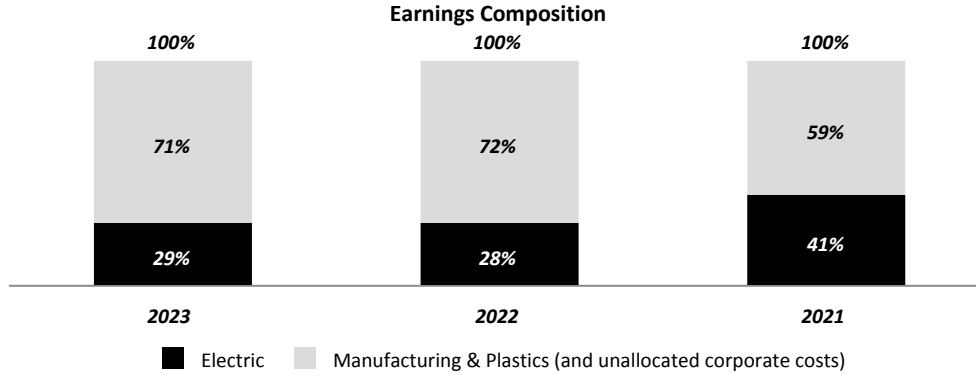
Over the past three years, we delivered earnings growth well in excess of our 5 - 7% target due to unique industry conditions within the PVC pipe industry, which led to extraordinary revenue, earnings and cash flow growth in our Plastics Segment. We expect these industry conditions to gradually normalize over the course of 2024 and into 2025. As they do, we expect earnings and cash flow generation within our Plastics segment to moderate from current levels. Once these industry conditions have normalized, we expect to achieve our long-term financial objectives as outlined above.

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 of 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, 2023, 2022 and 2021 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, and our executive annual incentive plan reflects those commitments. We monitor 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 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 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 2023 Total Recordable Incident Rate was 1.70, compared to 2.08 in 2022 and our Lost Time Incident Rate was 0.53 in 2023, compared to 0.49 in 2022.

Employee and Leadership Development, Succession Planning and Training Programs - We invest in training and professional development for various levels of employees, management and leaders throughout the Company to ensure all have the necessary training and skills to perform their work well, and 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.

Human Rights - We are committed to the protection of our employee’s freedom of expression and freedom of organization and assembly.

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 slates of interview candidates.

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, 2023, we employed 2,655 full-time employees as shown in the table below:

<i>Segment/Organization</i>	<i>Employees</i>
Electric Segment	
OTP ⁽¹⁾	790
Manufacturing Segment	
BTD	1,458
T.O. Plastics	192
Segment Total	1,650
Plastics Segment	
Northern Pipe	98
Vinyltech	80
Segment Total	178
Corporate	37
Total	2,655

⁽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, 2023, 378 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, 2026 and October 31, 2026. 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, 2023 was as follows:

	<i>% Female</i>	<i>% Racially and Ethnically Diverse</i>
Board of Directors	36 %	9 %
CEO Direct Reports	33 %	— %
Management	21 %	4 %
Non-Management Employees	15 %	15 %

ELECTRIC

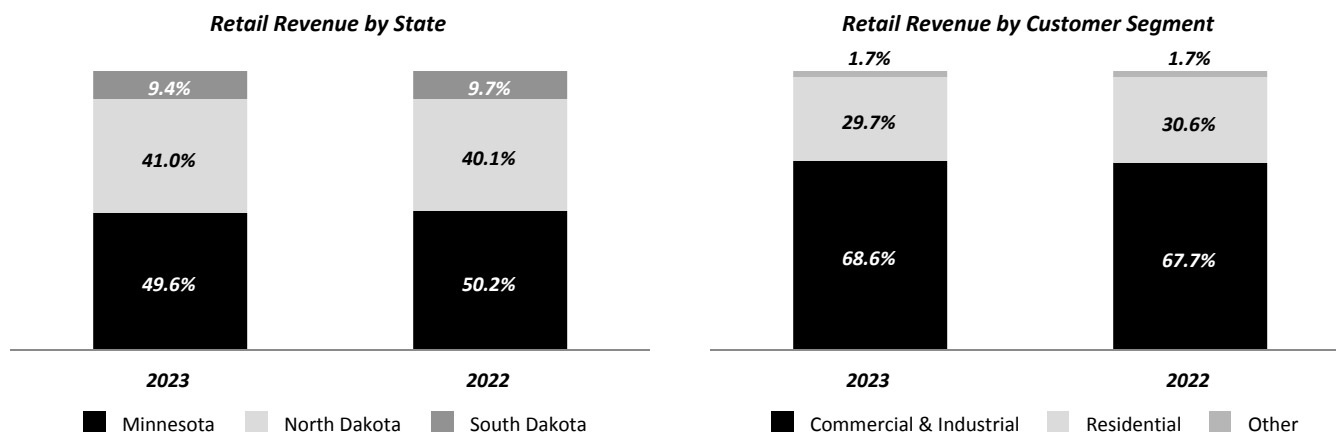
Contribution to Operating Revenues: 39% (2023), 38% (2022), 40% (2021)

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 two customers accounting for 21% of segment operating revenues for the year ended December 31, 2023 and 16% for the year ended December 31, 2022.

The following charts summarize our retail electric revenues by state and by customer segment for the years ended December 31, 2023 and 2022:



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, 2023 and 2022:

<i>Revenue per kwh</i>	2023	2022
Residential	10.82 ¢	10.99 ¢
Commercial & Industrial	7.02 ¢	7.54 ¢
Total Retail	7.90 ¢	8.41 ¢

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 under federal regulation. Certain states have laws which provide the incumbent transmission owner the right of first refusal to construct and own new transmission facilities.

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.

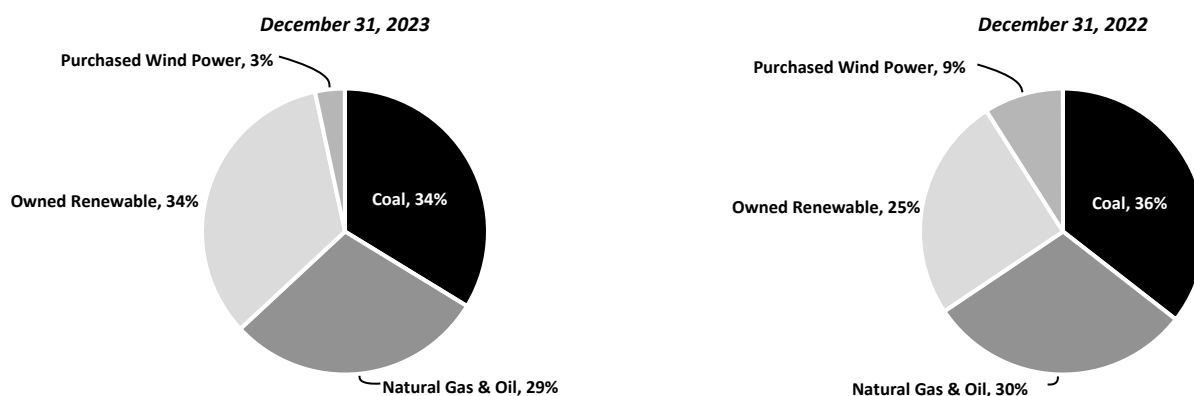
As of December 31, 2023, OTP’s wholly or jointly owned plants and facilities, as well as in place power purchase agreements, and their dependable kilowatt (kW) capacity were:

	<i>Capacity / Purchased Power in kW</i>
Owned Generation:	
Baseload Plants	
Big Stone Plant ⁽¹⁾	256,900
Coyote Station ⁽²⁾	148,400
Total Baseload Plants	405,300
Combustion Turbine and Small Diesel Units	
Astoria Station	249,700
All Other	102,800
Total Combustion Turbine and Small Diesel Units	352,500
Owned Wind Facilities (rated at nameplate)	
Merricourt	150,000
Ashtabula III	62,400
Luverne	49,500
Ashtabula	48,000
Langdon	40,500
Total Owned Wind Facilities	350,400
Hoot Lake Solar	49,900
Hydroelectric Facilities	2,600
Total Owned Generation Capacity	1,160,700
Power Purchase Agreements:	
Purchased Wind Power (rated at nameplate and greater than 2,000 kW)	
Edgeley	21,000
Langdon	19,500
Total Purchased Wind	40,500
Total Generating Capacity	1,201,200

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

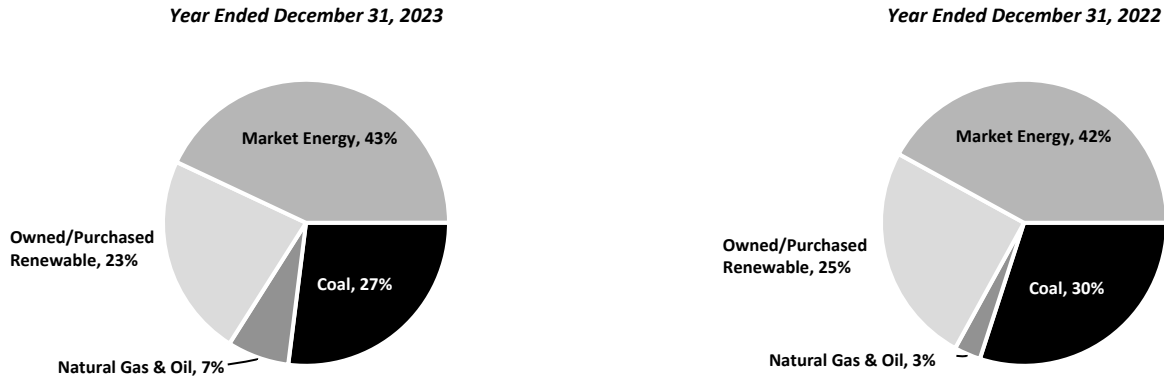
⁽²⁾ Reflects OTP’s 35.0% ownership percentage of jointly owned facility.

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, 2023 and 2022:



Under Midcontinent Independent System Operator (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. MISO operates under a seasonal resource adequacy construct in which generation resources are accredited and planning reserve margin requirements are implemented on a seasonal basis. Current 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, 2023 and 2022:



Capacity Additions

As part of our investment plan to meet our future energy needs, the following projects have been recently undertaken, completed, or acquired:

Ashtabula III Wind Farm is a 62-megawatt (MW) 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.

Hoot Lake Solar is a 49-MW solar farm constructed on and around our Hoot Lake Plant property in Fergus Falls, Minnesota, with a total cost of approximately \$60 million. The facility was placed into commercial operation in August 2023.

Wind Energy Facility Upgrades consisting of the replacement and upgrade of hubs, gearboxes, blades, generators and other components of our Ashtabula, Ashtabula III, Langdon and Luverne wind facilities at a total cost of approximately \$230 million. Once complete, we expect the increased energy production from these facilities will be equivalent to an additional 40-MW of generation. We anticipate the repowering of our Langdon facility will be completed in 2024 and the remaining facilities to be completed in 2025. Once complete, the energy production from each of these facilities is eligible for production tax credits (PTCs) over a ten-year period. We expect these projects will lower customer costs through a combination of fuel savings and the tax credit benefits afforded to our customers.

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:

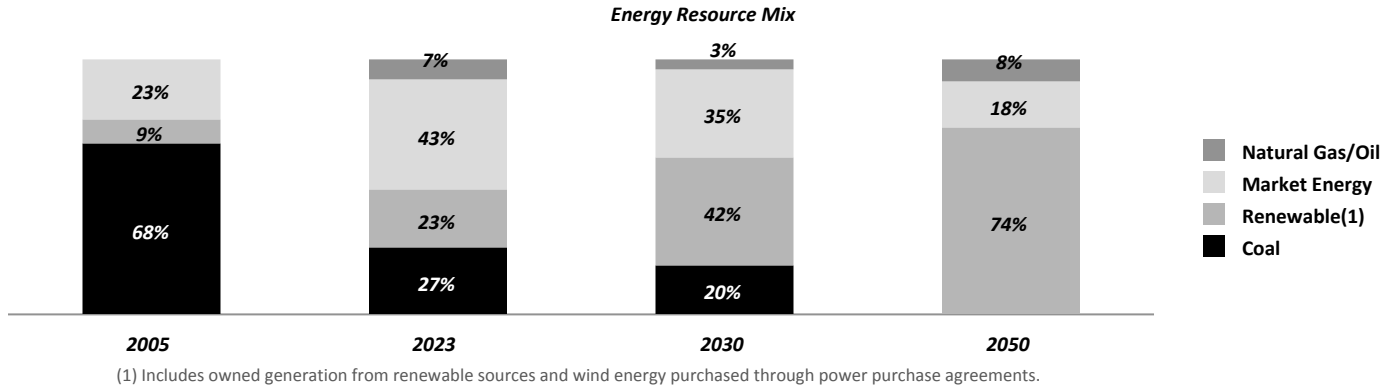
- Own or purchase energy generation that is **55% renewable by 2030**.
- Reduce carbon emissions** from owned generation resources **50% by 2030** from 2005 levels.
- Reduce carbon emissions** from owned generation resources **97% by 2050** from 2005 levels.

We have based these goals on our December 2023 supplemental Integrated Resource Plan (IRP) filing in Minnesota. While modified from our previously published goals, they reflect current market conditions, including the impact of higher natural gas prices, and higher than originally forecasted dispatch levels of our co-owned, coal-fired power plants.

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 recent initiatives include retiring the 140-MW coal-fired Hoot Lake Plant, adding the 150-MW Merricourt Wind Energy Center and the 49-MW Hoot Lake Solar facility to our resource mix and sponsoring energy conservation programs. We anticipate our Minnesota retail sales will be 80% carbon free by 2030, in compliance with Minnesota clean energy requirements.

From 2005 through 2023, we have reduced our carbon dioxide (CO₂) emissions approximately 39% and increased the amount of renewable generation resources we own or purchase through power purchase agreements by approximately 420-MW. We currently own or contract energy generation that is 37% renewable.

The following chart depicts our energy resource mix, which is the electricity we used to serve our customers in 2005 and 2023, 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:



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, respectively.

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 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, 2023, we were the sole or joint owner of approximately 14,000 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.

Transmission Additions

In 2022, MISO approved several projects within the first tranche of its long-range transmission plan, which includes two new 345 kV transmission projects. OTP will have a varying level of ownership interest in these projects, which will be completed over several years and are at various stages of planning and development:

Jamestown-Ellendale includes the construction of a new 345 kV transmission line in southeastern North Dakota spanning approximately 95 miles from Jamestown, North Dakota to Ellendale, North Dakota. This project is in the initial stages of planning and development. This jointly owned project is expected to be completed in 2028 and our capital investment is estimated to be approximately \$230 million.

Big Stone South-Alexandria-Big Oaks includes the construction of a new 345 kV transmission line in eastern South Dakota and western Minnesota and the addition of a second circuit to an existing 345 kV line in central Minnesota. The new transmission line will span approximately 100 miles between Big Stone, South Dakota and Alexandria, Minnesota. A second circuit will be added to the existing transmission line spanning from Alexandria, Minnesota to Big Oaks, Minnesota. This project is in the initial stages of planning and development. This jointly owned project is expected to be completed in 2031 and our capital investment is estimated to be approximately \$190 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 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 our capital investments 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. In Minnesota, fuel and purchased power costs are estimated on an annual basis and the accumulated difference between actual and estimated cost per kwh is 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.
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.
Energy Conservation and Optimization Rider (ECO)	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 ECO 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.
Metering and Distribution Technology Cost Recovery Rider (MDT)	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.

Resource Planning

Under Minnesota law, utilities are required to submit for approval by the Minnesota Public Utilities Commission (MPUC) a 15-year advance Integrated Resource Plan (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.

In 2021, the North Dakota Legislative Assembly enacted a provision requiring investor-owned electric utilities to submit an IRP to the North Dakota Public Service Commission (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 a 15-year advance IRP every three years.

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 August 29, 2023, allows for an equity-to-total-capitalization ratio between 48.3% and 59.1%, with total capitalization not to exceed \$1.958 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. We met the current solar requirement with a combination of owned solar generation and solar renewable energy certificate (REC) purchases. We plan to comply with the requirements of this standard in the future through a combination of our existing and projected renewable generation fleet and the purchase of RECs.

Minnesota Clean Energy Bill

In February 2023, 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 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. We expect to meet these requirements based on our existing and projected renewable generation fleet and the purchase of RECs.

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.

Financial Impacts

For the five-year period ended December 31, 2023, OTP invested approximately \$6.6 million in environmental control facilities, including \$1.4 million in 2023. Our construction budget for the next five years includes approximately \$7.5 million of capital investments in environmental control equipment. The timing and amount of our expenditures may change as the regulatory environment changes.

Emerging Regulation

The Environmental Protection Agency (EPA) adopted the Regional Haze Rule (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) that work towards achieving natural visibility conditions by the year 2064; to set goals to ensure reasonable progress is being made; and 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.

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 RHR 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. See Note 13 to our consolidated financial statements for additional information. At this time we are unable to predict the ultimate impact, however, there could be a cost of compliance which could have a material impact on our operating results, financial condition and liquidity.

In April 2023, the EPA released a proposal to tighten aspects of the Mercury and Air Toxics Standards, including the reduction of emissions limits for filterable particulate matter, and requiring the use of continuous emissions monitoring systems to demonstrate compliance. Until the EPA takes final action on this rulemaking, we are unable to predict the ultimate impact, however, there could be a cost of compliance which could have a material impact on our operating results, financial condition and liquidity.

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 CO₂ 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 set goals of reducing GHG emissions by 50% to 52% from 2005 levels in 2030 and reaching 100% carbon pollution-free electricity by 2035 as part of the U.S. plan to achieve the goals under the Paris Agreement.

In February 2023, 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 May 2023, the EPA proposed new regulations under Section 111 of the Clean Air Act to regulate GHG emissions from existing and new fossil fuel-based electric generating units (EGU). The proposal provides requirements for different types of fossil fuel-based EGUs with various compliance dates.

- For existing coal-fired steam generating units that were in operation before January 8, 2014 and that plan to operate past December 31, 2039, the proposal would (subject to certain exceptions) set emissions standards that reflect the use of carbon capture and sequestration (CCS) with 90% capture of CO₂ emissions beginning in 2030.
- For existing coal-fired steam generating units that are scheduled to be retired between January 1, 2032 and December 31, 2039, the proposed rule would, in general, set emissions standards that reflect the use of co-firing 40% natural gas with coal beginning in 2030.
- For existing coal-fired steam generating units that will either (a) retire by January 1, 2032, or (b) retire between 2032 and December 21, 2034 and will operate at a 20% annual capacity factor limit in the meantime, the proposed rule would simply require routine maintenance and no increase in emission rate.

The proposal also includes emission standards for existing large (greater than 300 mega-watt), frequently used (those that operate at a capacity factor over 50%) natural gas combustion turbines, including which emission standard would reflect the use of CCS by 2035 or co-firing with low-GHG hydrogen at incremental portions in 2032 (30% of volume) and 2038 (96% of volume). Under the proposed rule, each state must submit a plan to the EPA to implement standards that are at least as stringent as the EPA's emission guidelines, unless states demonstrate that due to remaining useful life and other factors, a facility cannot reasonably achieve the standards. The EPA is proposing to require states to submit their plans within 24 months of the effective date of the final regulation. This proposed rule has the potential to impact the emissions controls needed at OTP's coal-fired power plants, which could have an impact on our operating results, financial condition and liquidity.

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: 30% (2023), 27% (2022), 28% (2021)

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 facilities in Detroit Lakes and Lakeville, Minnesota, Washington, Illinois and Dawsonville, Georgia, provides metal fabrication services for custom machine parts and metal components through metal stamping, tool and die, machining, tube bending, welding and assembly.

T.O. Plastics, Inc. (T.O. Plastics), with facilities in Otsego and Clearwater, Minnesota, manufactures thermoformed plastics products, including its own line of horticulture containers and custom packaging products for the medical and industrial product markets.

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 2023. However, two customers combined to account for 30% of segment operating revenues for the year ended December 31, 2023 and 40% for the year ended December 31, 2022.

COMPETITIVE CONDITIONS

We compete in a highly fragmented market with competition from both domestic and international entities. Our competitors vary in size, ranging from small companies focused on certain end markets or geographical area, to large companies with broad manufacturing capabilities and geographical reach. Competition can be geographically regionalized as customers procure products locally to manage cost and minimize logistical complexities. Certain competitors may have broader product lines, more manufacturing capacity, and greater distribution capabilities than we do.

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 quality 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: 31% (2023), 35% (2022), 32% (2021)

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 an extrusion process, during which 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 2023. However, two customers, both of which are distributors of PVC pipe, combined to account for 36% of segment operating revenues for the year ended December 31, 2023 and 46% for the year ended December 31, 2022.

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, including our responsiveness and reliability.

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 2023 we sourced all of our PVC resin from three 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.

OPERATIONAL RISKS

Our strategy includes large capital investments, which are subject to risks.

Our business strategy includes major capital investments at our operating companies. These capital projects are planned years in advance of their in-service dates and are subject to various risks including: adverse changes in regulatory treatment or public policy; changes in commodity pricing or construction costs; delivery of critical materials; obtaining necessary permits and licenses; and other adverse conditions. Capital investments in our Electric segment require regulatory approval and are subject to the risks of not being granted timely approval or allowed to be fully recovered. In addition, our ability to construct and own utility assets may be impacted by regulatory requirements to competitively bid such investments, which could impact the amount and timing of our capital investments. A lack of direct ownership, or the inability to complete capital projects on budget and in a timely manner could impact our ability to achieve our strategic financial goals and could adversely impact our operating results and financial condition.

Weather impacts, including seasonal fluctuations, could adversely affect our operating results.

Our Electric segment business is seasonal and weather patterns have had an impact on our financial performance in the past and may again in the future. 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. Our Plastics segment businesses can be affected by seasonal 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 and could have an adverse effect on our financial condition, operating results and liquidity.

We are subject to physical and transition risks associated with climate change and extreme weather events.

Longer term shifts in climate patterns may impact our customers' demand for electricity, interrupt our business operations and damage our facilities; reduce the availability of natural resources, such as water; and cause disruptions in our supply chains.

Climate change may increase the frequency and severity of extreme weather events, such as prolonged periods of extreme cold or heat, and natural disasters, such as severe snow and ice storms, tornadoes, flooding and wildfires. These acute events could result in the interruption of our business operations 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 reduced operating revenues and repair or replacement costs, due to downed wires and poles or damage to other operating equipment.

In the past, severe weather events in the Gulf Coast region of the U.S. have disrupted the supply of PVC resin, the primary material input of our Plastics segment businesses. As most U.S. PVC resin production plants are located in the Gulf Coast region, an area 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, which could impact our Plastics segment businesses.

Increased risk of natural disasters, such as wildfires, could have financial consequences, including limiting our ability to secure sufficient insurance coverage, or lead to increased insurance cost. While we carry liability insurance, given an extreme event, if we were found to be liable for damages, amounts that exceed our coverage limit could negatively impact our financial condition, operating results and liquidity.

These risks may also negatively impact our credit ratings, which may limit our access to capital markets and increase our borrowing costs. In addition, 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.

We may experience transition risks in moving towards low carbon generation and manufacturing. For example, we may face challenges with the adoption of new technologies, meeting changing customer expectations and committing to voluntary GHG emissions reduction goals, as well as complying with evolving local, state or federal regulatory requirements intended to reduce GHG emissions.

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 2023, two customers accounted for 21% of Electric segment revenues, two customers combined to account for 30% of Manufacturing segment operating revenues and two customers combined to account for 36% 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.

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. New laws or regulations or changes to existing laws and regulations in the future may result in disruptions to our business, changes in customer preferences, or changes in customer demand, which could adversely impact our financial condition, operating results and liquidity.

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. Regulators have recently proposed additional chemicals be designated as hazardous substances, including a proposal to designate perfluorooctanesulfonic acid and perfluorooctanoic acid, 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, as well as that of third-party service providers and vendors we use 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. Cyber-attacks or other security breaches may also be perpetrated through the use of artificial intelligence, which could introduce additional complexity to such an attack or breach. 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 disclosure laws and 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.

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.

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 2023, 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 (ITCs), or the ability to transfer or sell these 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.

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. Diverging public policy priorities across the jurisdictions we serve, and a lack of inter-jurisdictional consensus, may impact our ability to recover the cost of, and return on, our capital investments and our operating costs; it may impact our future capital investment opportunities; and may result in inefficiencies which could negatively impact our financial position, operating results and liquidity.

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 or any prolonged delay in rendering a decision in a rate or other proceeding could adversely impact our financial condition, operating results and liquidity.

Inflationary cost pressures have increased the cost of constructing our utility assets and operating our utility business. There can be no assurance that our state regulatory commissions will authorize recovery of rising costs. Regulatory commissions may also limit future capital investments or the rate of return allowed on such investments in response to inflationary cost pressures and customer bill impacts. Such limitations could negatively impact our financial position, 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 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 potentially expose us 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.

Our IRP, as revised in two supplemental filings in 2023, outlined our plan to withdraw from our 35% ownership interest in Coyote Station, a jointly owned coal-fired generation plant, in the event we are required to make a major, non-routine capital investment in the plant. In the event we were to withdraw from our ownership, we will seek to recover all costs related to the withdrawal from Coyote Station; however, there is a risk we may not be granted recovery of such costs. A full or partial denial of recovery of the costs of withdrawal could significantly impact our operating results, financial condition 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.

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 RHR 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 or the sale of, or withdrawal from, 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 CO₂ emission levels, taxes on CO₂ 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% from 2005 levels by 2030. In addition, the Administration set a goal to reach 100% carbon pollution-free electricity by 2035. As a part of achieving these targets, the EPA proposed new regulations in May 2023 under Section 111 of the Clean Air Act to regulate GHG emissions from existing and new fossil fuel-based EGUs. As detailed above, this proposal would require states to implement stringent emissions standards for most coal-fired steam generating units and certain larger natural gas combustion plants. Until the EPA takes final action on this rulemaking, we are unable to evaluate the precise impacts; however, the proposed rule has the potential to impact the emissions controls needed at OTP's coal-fired power plants, which could have an impact on our operating results, financial condition and liquidity. The EPA may implement additional new regulations targeting power plants to

support its aforementioned economy-wide GHG reduction goals, which 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.

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 North American Electric Reliability Corporation (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 generation, transmission, and distribution facilities are subject to operational risks which include circumstances that could result in injuries, loss of life, property damage, and fires.

The operation of our generation, transmission, and distribution facilities involves many risks including equipment failures, accidents and workforce safety matters, environmental damage, property damage, operator error, and the occurrence of catastrophic events such as fires, explosions and floods. Diminished availability or performance of those facilities could result in facility shutdowns, reduced customer satisfaction, reputational harm, and regulatory inquiries and fines.

Accidents, fires, explosions, catastrophic failures, general system damage or dysfunction, intentional acts of destruction, and other unplanned events related to our infrastructure would increase repair costs and may expose us to liability for personal injury, loss of life, and property damage. Fires alleged to have been caused by our transmission, distribution, or generation infrastructure, or that allegedly result from our contractors' operating or maintenance practices, could also expose us to claims for fire suppression and clean-up costs, evacuation costs, fines and penalties, and liability for economic damages, personal injury, loss of life, property damage, and environmental pollution, whether based on claims of negligence, trespass, or otherwise. We maintain insurance coverage for such operating and event risks, but insurance coverage is subject to the terms and limitations of the available policies and may not be sufficient in amount to cover our ultimate liability. We may be unable to fully recover costs in excess of insurance through customer rates or regulatory mechanisms. If the amount of insurance is insufficient or otherwise unavailable, and if we are unable to fully recover in rates the costs of uninsured losses, our financial condition, operating results and liquidity could be materially affected.

We are subject to risks associated with the procurement and transportation of fuel to our coal and natural gas powered generation facilities.

We rely on a limited number of suppliers to provide coal and a limited number of service providers to transport coal and natural gas to our facilities. A counterparty's failure to perform their obligations 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. A prolonged failure to perform by one or more of our current suppliers or service providers could lead to increased costs or other consequences which could negatively 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 domestic and foreign manufacturers could affect the revenues and earnings of our manufacturing businesses.

Our manufacturing businesses are subject to intense competition from domestic and foreign 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

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 demand for our products and sales prices impacting our 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; and
- funding shortages for municipal water and wastewater projects.

Extraordinary industry supply and demand dynamics beginning in 2021 and continuing through 2023 led to a rapid and significant increase in sales prices for PVC pipe and led to a significant expansion in our operating margins. As industry conditions normalize, sales prices for PVC pipe are expected to moderate from current levels resulting in decreased operating margins prospectively. The pace and magnitude of the decline in product pricing could materially impact our operating results.

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.

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 businesses. In 2023, we sourced all of our PVC resin needs from three 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.

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 effects of a major public health crisis, such as an epidemic or pandemic, and measures taken to reduce and slow the spread of the disease could adversely impact our business.

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 1C. CYBERSECURITY

CYBERSECURITY RISK

The operation of our businesses is dependent on the secure functioning of our computer infrastructure and digital information 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 service providers to electronically process certain of our business transactions and perform certain cyber-related functions, such as system monitoring and critical infrastructure protection and maintenance. The confidentiality, integrity, and availability of information systems, both ours and those of our third-party service providers, 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 other business partners. As part of our utility operations, we own electric generation, transmission and distribution facilities that are part of an interconnected regional grid, the operation of which is dependent on information technology systems. Parties who wish to disrupt the U.S. bulk power system or our utility operations could view our computer systems, software or networks as attractive targets for cyber-attack. Although we have not historically experienced material cyber incidents, we and other utilities are subject to cyber-attacks of increasing frequency and sophistication, and any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches, could adversely affect our business and our financial condition, operating results and liquidity.

RISK MANAGEMENT AND STRATEGY

Our cybersecurity policies and practices, which are based on the Center for Information Security (CIS) Critical Security Controls, are governed by our information and cybersecurity governance program. The CIS Critical Security Controls are a set of 18 cybersecurity-related controls which aid companies in designing an effective control environment and are viewed as best practices by organizations worldwide. A significant number of our cybersecurity policies and practices associated with our electric utility operations are also subject to regulation by multiple governmental and other agencies.

Our information and cybersecurity governance program is the foundation of our cybersecurity risk management strategy. The program includes policies which authorize and guide the development of procedures, standards, and guidelines for personnel activities, incident prevention and reporting, and compliance monitoring. Cybersecurity policies, procedures and controls are reviewed and approved by our Information and Cybersecurity Program (ICSP) group annually, with amendments made as deemed necessary for any updates for regulatory compliance and best practices, legal privacy protection and information protection, or to reflect current technology or new methods for ensuring secure business procedures.

We perform a corporate risk assessment annually, which includes specific consideration and assessment of cybersecurity risk. As part of our risk assessment process, we incorporate results from procedures performed by third-party consultants. We utilize third-party consultants to complete risk quantification analysis and perform penetration and vulnerability testing and monitoring, as well as overall cybersecurity control testing. Potential risks associated with the use of third-party service providers are monitored and managed through an established service provider management policy. Service providers must meet certain security requirements such as security incident or data breach notification and response protocols, data encryption requirements, and data disposal commitments.

In managing cybersecurity risk, we employ a defense-in-depth strategy and regularly monitor our cyber environment for potential new threats. Our strategy includes employee training and awareness on cybersecurity risks and related best practices, required password complexity, the use of multi-factor authentication, information security protocols, anti-virus and anti-ransomware software, a patch management program, the execution of tabletop exercises on a periodic basis, established policies and protocols for cyber incident response planning and reporting, and ongoing internal cybersecurity testing.

GOVERNANCE

At the management level, our cyber program is managed by our ICSP group. The ICSP group consists of Information Technology (IT) managers, IT security subject matter experts, and internal audit personnel and is led by our Vice President of IT who has more than 25 years of experience in IT, enterprise security, and cyber risk management, a Bachelor's degree of Science, CIS, Information Technology and Master's of Business, Information Systems, and holds Certified Information Systems Security Professional, Certified Information Security Manager, and Certified Data Privacy Solution Engineer designations. The ICSP group is in charge of developing, maintaining, and measuring compliance with the information and cybersecurity governance program, as well as monitoring cyber incidents and implementing mitigation measures as part of an evolving, dynamic external environment. Our approach to cybersecurity incident reporting and response planning is governed by our incident response plans established for

each of our business units. The plans outline the processes related to detecting, assessing, investigating, mitigating, and remediating cyber incidents, as well the communication and reporting plan and the required personnel to be included in the process and communications.

Our cybersecurity risk management is integrated into our overall risk management system through our internal business risk management process. Our business risk management group works closely with our ICSP group to regularly assess and identify possible material risks from cybersecurity threats, including, but not limited to, financial, operations, reputational and regulatory impact to the Company, as well as impacts on our employees and customers. Their risk assessment results are reported to the Executive Risk Committee on a quarterly basis. The Executive Risk Committee, which is comprised of our executive officers, meets quarterly to identify and assess short-, medium- and long-term risks, and to ensure adequate mitigation strategies are implemented. During these meetings, the Executive Risk Committee reviews significant and emerging risks, including cybersecurity risks, and assesses the Company’s plans to mitigate or otherwise manage and monitor those risks.

Our Board of Directors provides oversight of our cybersecurity program through quarterly and annual risk review and cybersecurity reporting. On a quarterly basis, cybersecurity risk and mitigation strategies are reviewed as part of our business risk management group's reporting to the Board of Directors, which includes the reporting of significant business risks, including cybersecurity mitigation strategies employed to manage these risks, and a review of any emerging risks. Annually, our Vice President of IT provides an overview of our cybersecurity program to the Board of Directors, including a review of key strategies, emerging risks and a summary of key performance indicators. In addition, annually the Board of Directors reviews the results of our penetration and vulnerability testing.

ITEM 2. PROPERTIES

The following provides a summary of our properties which are material to our operations, by segment, as of December 31, 2023.

ELECTRIC SEGMENT

The following reflects our wholly or jointly owned material electric generation facilities as of December 31, 2023:

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 Turbines	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 Energy Center	Cavalier County, ND	2007	Wind	40,500
Ashtabula Wind Energy Center	Barnes County, ND	2008	Wind	48,000
Luverne Wind Energy Center	Griggs and Steele Counties, ND	2009	Wind	49,500
Merricourt Wind Energy Center	McIntosh and Dickey Counties, ND	2020	Wind	150,000
Ashtabula III Wind Energy Center	Barnes County, ND	2023 ⁽³⁾	Wind	62,400
Hoot Lake Solar	Otter Tail County, MN	2023	Solar	49,900

⁽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.

⁽³⁾ Originally placed in service in 2010 and owned by an unrelated third party. OTP acquired this facility in 2023.

In addition to our generation facilities, we wholly or jointly own transmission and distribution lines as of December 31, 2023 as follows:

	Miles
Transmission	
345 kV ⁽³⁾	891
230 kV ⁽⁴⁾	496
115 kV	961
Less than 115 kV	4,005
Distribution	
Less than 115 kV	7,998

⁽³⁾ As of December 31, 2023, 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, 2023, 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, 2023:

<i>Segment/Location</i>	<i>Owned/Leased</i>	<i>Facility Type/Use</i>	<i>Approximate Square Feet</i>
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
Phoenix, AZ	Owned	Office/Manufacturing/Warehouse	87,336

We are currently undertaking an expansion project at our Georgia location which will add approximately 162,000 square feet of manufacturing and warehouse space, and will replace the warehouse facility that is currently being leased. We anticipate the project will be completed in 2025. We are also undertaking an expansion project at our Arizona location which will add approximately 65,000 square feet of manufacturing, warehouse, and office space. We anticipate the project will be completed in 2024.

We believe the facilities described above, along with the planned expansions, 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.

<i>Name and Age</i>	<i>Date Elected to Office</i>	<i>Current Position</i>
Charles S. MacFarlane (59)	04/13/15	President and Chief Executive Officer
Todd R. Wahlund (53)	01/01/24	Vice President, Chief Financial Officer
Timothy J. Rogelstad (57)	04/14/14	Senior Vice President, Electric Platform
John S. Abbott (65)	02/11/15	Senior Vice President, Manufacturing Platform
Jennifer O. Smestad (53)	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.

Todd Wahlund was appointed to succeed Kevin Moug, Chief Financial Officer and Senior Vice President, subsequent to Mr. Moug's retirement on December 31, 2023. Mr. Wahlund has served as Chief Financial Officer and Vice President since January 1, 2024, and previously served as Chief Financial Officer and Vice President, Finance for OTP from May 1, 2018 to December 31, 2023.

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 11, 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

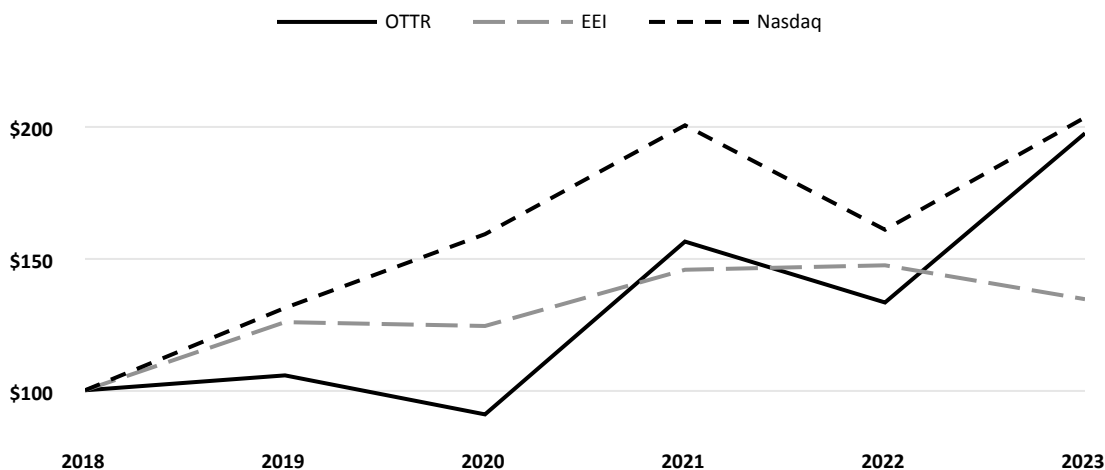
ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the Nasdaq Global Select Market under the Nasdaq symbol "OTTR". As of December 31, 2023, there were 10,650 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 quarter ended December 31, 2023.

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, 2018, and reinvestment of all dividends).



		2018		2019		2020		2021		2022		2023
OTTR	\$	100.00	\$	105.64	\$	90.88	\$	156.27	\$	133.22	\$	197.24
EEI	\$	100.00	\$	125.79	\$	124.33	\$	145.61	\$	147.29	\$	134.47
Nasdaq	\$	100.00	\$	131.17	\$	159.07	\$	200.26	\$	160.75	\$	203.23

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 long-term targeted annual growth in earnings per share of 5 - 7%.

2023 FINANCIAL RESULTS

In 2023, our diversified business model generated record financial results, producing net income of \$294.2 million, or \$7.00 per diluted share, an increase of 4% from \$284.2 million, or \$6.78 per diluted share, in 2022. Our financial results for the year were driven by earnings growth in our Electric and Manufacturing segments, as well as lower corporate costs, as we benefited from returns on our short-term investments funded by the significant cash flows our businesses have generated over the last three years. Our Plastics segment again produced extraordinary financial results as we continued to capitalize on favorable industry dynamics; however, earnings in this segment did decline modestly from the record level achieved in 2022. In 2023, we paid an annual dividend of \$1.75 per share, or \$73.1 million, completing our 85th consecutive year of dividend payments to our shareholders.

Our Electric segment produced earnings growth of 6% in 2023, from \$80.0 million in 2022 to \$84.4 million in 2023, primarily due to increased rider revenue, increased commercial and industrial sales, and lower pension and other postretirement benefit costs, partially offset by increased operating and maintenance expenses and the impact of unfavorable weather.

Our Manufacturing segment produced earnings growth of 2% in 2023, from \$21.0 million in 2022 to \$21.5 million in 2023, primarily due to increased sales volumes at our metal fabrication business driven by strong end market demand across several markets we serve, and incremental volumes from additional work with existing customers. Increased sales volumes at our metal fabrication business were partially offset by increased labor and overhead costs, as well as decreased horticulture product sales volumes at our plastic thermoforming business.

Our Plastics segment earnings declined 4%, from \$195.4 million in 2022 to \$187.7 million in 2023. We experienced an unprecedented level of earnings in 2022, resulting from extraordinary industry supply and demand dynamics. Industry dynamics have begun to moderate, but at a modest pace, as further described below. Our Plastics segment businesses continued to capitalize on these industry conditions in 2023, producing earnings significantly in excess of pre-2021 levels.

Our earnings mix in 2023 was 29% from our Electric segment and 71% from the combination of our Manufacturing and Plastics segments excluding 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 occurring in the plastics industry.

PVC PIPE SUPPLY AND DEMAND CONDITIONS

Extraordinary supply and demand conditions in the PVC industry beginning in 2021 have led to a significant expansion in operating margins and elevated earnings in our Plastics segment over the past three years. Periodic disruptions in the supply of resin, the primary material input used in the manufacturing of PVC pipe, coupled with robust demand for resin, led to a significant increase in the cost of resin beginning in 2021. Low industry volumes of PVC pipe and robust end market demand for the product led to a rapid and significant increase in sales prices for PVC pipe, significantly outpacing the increase in resin input costs, leading to increased operating margins within our Plastics segment.

Demand for PVC pipe began to soften in the second half of 2022, as distributors and contractors reduced purchase volumes in response to uncertain and competitive market conditions. Softening demand continued through the first half of 2023, but sales volumes in the second half of the year exceeded those in the previous year. Resin prices have declined from the previous year and although sales prices for PVC pipe have also declined, they have declined at a slower pace than resin prices, continuing to produce expanded operating margins from those experienced in 2022.

The unique market dynamics impacting our Plastics segment resulted in a significant increase in earnings in the last three years compared to historical levels. We expect these market conditions to gradually normalize over the course of 2024 and into 2025. The marketplace dynamics impacting our Plastics segments are fluid and subject to change and 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, construction work in progress, deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and, in some cases, accumulated deferred ITCs. 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 2022 to 2021, 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, 2022, filed with the SEC on February 15, 2023.

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, 2023 and 2022:

<i>(in thousands)</i>	2023		2022		\$ change	% change
Operating Revenues	\$	1,349,166	\$	1,460,209	\$ (111,043)	(7.6)%
Operating Expenses		971,247		1,069,770	(98,523)	(9.2)
Operating Income		377,919		390,439	(12,520)	(3.2)
Interest Expense		(37,677)		(36,016)	(1,661)	4.6
Nonservice Components of Postretirement Benefits		10,597		1,075	9,522	n/m
Other Income		12,650		2,037	10,613	n/m
Income Before Income Taxes		363,489		357,535	5,954	1.7
Income Tax Expense		69,298		73,351	(4,053)	(5.5)
Net Income	\$	294,191	\$	284,184	\$ 10,007	3.5 %

Operating Revenues decreased \$111.0 million on a consolidated basis in 2023. Electric segment operating revenues decreased 4% primarily due to decreased fuel recovery and wholesale revenues and the impact of unfavorable weather, partially offset by increased rider revenues and increased commercial and industrial sales. Manufacturing segment operating revenues increased 1% primarily due to higher sales volumes in our metal fabrication business. Plastics segment operating revenues decreased 18% due to a combination of decreased sales volumes and sales prices. See our segment disclosures below for additional discussion of items impacting operating revenues.

Operating Expenses decreased \$98.5 million in 2023. Electric segment operating expenses decreased primarily due to decreased purchased power costs resulting from lower market energy prices and lower fuel costs due to decreased natural gas prices. Operating expenses in our Manufacturing segment increased primarily due to increased sales volumes in our metal fabrication business and an increase in certain variable compensation costs. Operating expenses in our Plastics segment decreased primarily due to lower sales volumes and decreased PVC resin costs. See our segment disclosures below for additional discussion of items impacting operating expenses.

Interest Expense increased \$1.7 million in 2023 due to an increase in our average short-term borrowings, primarily used to fund capital investments in our Electric segment, and increased interest rates on our short-term borrowings.

Nonservice Components of Postretirement Benefits improved by \$9.5 million in 2023, having a positive impact on net income, primarily due to a change in actuarial assumptions used to measure our pension benefit and postretirement benefit obligations, including an increase in the discount rate applied and an increase in the expected return on assets assumption.

Other Income increased \$10.6 million in 2023 primarily due to an increase in investment income earned on our short-term cash equivalent investments and investment gains from our corporate-owned life insurance policies compared to investment losses in the previous year.

Income Tax Expense decreased \$4.1 million in 2023 primarily due to an increase in PTCs produced by our wind and solar generation assets. Our effective tax rate was 19.1% in 2023 and 20.5% in 2022. See Note 12 to our consolidated financial statements included in this 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, 2023 and 2022:

<i>(in thousands)</i>		2023		2022	\$ change	% change
Retail Sales Revenue	\$	455,840	\$	470,300	\$ (14,460)	(3.1)%
Transmission Services Revenues		52,555		52,213	342	0.7
Wholesale Revenues		12,459		18,539	(6,080)	(32.8)
Other Electric Revenues		7,505		8,647	(1,142)	(13.2)
Total Operating Revenue		528,359		549,699	(21,340)	(3.9)
Production Fuel		60,339		65,110	(4,771)	(7.3)
Purchased Power		78,292		100,281	(21,989)	(21.9)
Operating and Maintenance Expenses		191,263		181,378	9,885	5.4
Depreciation and Amortization		75,330		72,050	3,280	4.6
Property Taxes		16,614		17,742	(1,128)	(6.4)
Operating Income	\$	106,521	\$	113,138	\$ (6,617)	(5.8)%

Electric kwh Sales (in thousands)						
Retail kwh Sales		5,772,215		5,592,368	179,847	3.2 %
Wholesale kwh Sales		351,729		267,184	84,545	31.6
Heating Degree Days		6,259		7,122	(863)	(12.1)
Cooling Degree Days		590		531	59	11.1

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, 2023 and 2022:

	2023	2022
Heating Degree Days	98.4 %	112.5 %
Cooling Degree Days	127.2 %	113.5 %

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail sales under actual weather conditions and expected retail sales under normal weather conditions for the years ended December 31, 2023 and 2022, and between years:

	2023 vs Normal		2023 vs 2022		2022 vs Normal	
Effect on Diluted Earnings Per Share	\$	0.02	\$	(0.09)	\$	0.11

Retail Revenues decreased \$14.5 million primarily due to the following:

- A \$26.2 million decrease in fuel recovery revenues, primarily due to lower purchased power and fuel costs arising from decreased market energy costs and natural gas prices, as described below.
- A \$5.2 million decrease in revenues from the unfavorable impact of weather compared to last year.
- Our Minnesota rate case, which was finalized in 2022, included a determination of the final interim rate refund and resulted in an additional \$4.1 million of retail revenue last year.

The decreases in retail revenues described above were partially offset by the following:

- A \$10.5 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 added during 2022.
- A \$9.6 million increase in rider revenues, including recovery of our investment in the Ashtabula III wind farm, which we acquired in January 2023, and the recovery of our investment in Hoot Lake Solar, which was completed during the year, as well as operating costs associated with these facilities.

Wholesale Revenues decreased \$6.1 million primarily due to a 49% decrease in wholesale electric prices driven by decreased fuel costs.

Production Fuel costs decreased \$4.8 million due to a 17% decrease in fuel cost per kwh resulting from decreases in natural gas prices, partially offset by an increase in kwhs generated from our natural gas-burning plants.

Purchased Power costs to serve retail customers decreased \$22.0 million due to a 14% decrease in the price of purchased power per kwh, primarily due to decreased market energy costs, as well as decreased purchase volumes due to the acquisition of the Ashtabula III wind farm and completion of our Hoot Lake Solar project in the current year. Prior to the acquisition of Ashtabula III, OTP purchased the wind generated electricity from the facility under the terms of a power purchase agreement.

Operating and Maintenance Expense increased \$9.9 million primarily due to:

- A \$3.9 million increase in labor and benefit costs partially due to increased health insurance costs, wage increases, and increased headcount.
- A \$2.2 million increase in vegetative maintenance costs.
- A \$1.9 million increase in insurance expense due in part to the addition of Ashtabula III and Hoot Lake Solar to our generation fleet during the year.
- A \$1.3 million increase in maintenance related to the addition and operation of Ashtabula III.

These expense increases were partially offset by, among other items, decreased outage-related costs and travel costs compared to the previous year.

Depreciation and Amortization expense increased \$3.3 million primarily due to the acquisition of Ashtabula III and continued investment in distribution facilities during the year.

MANUFACTURING SEGMENT RESULTS

The following table summarizes the operating results of our Manufacturing segment for the years ended December 31, 2023 and 2022:

<i>(in thousands)</i>	2023	2022	\$ change	% change
Operating Revenues	\$ 402,781	\$ 397,983	\$ 4,798	1.2 %
Cost of Products Sold (excluding depreciation)	310,601	315,375	(4,774)	(1.5)
Selling, General, and Administrative Expenses	44,545	37,341	7,204	19.3
Depreciation and Amortization	18,495	16,202	2,293	14.2
Operating Income	\$ 29,140	\$ 29,065	\$ 75	0.3 %

Operating Revenues increased \$4.8 million primarily due to the combination of the following:

- At BTD, operating revenues increased \$12.5 million primarily 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 in several segments, including the construction, industrial, and agricultural segments, and incremental volumes from additional work with existing customers. Sales price increases were implemented during the year in response to labor and non-steel material cost inflation. Sales price increases and sales volume growth were partially offset by decreased steel prices, resulting in an 11% decrease in material costs, which are passed through to customers.
- At T.O. Plastics, operating revenues decreased \$7.7 million primarily due to lower sales volumes. Sales volumes decreased 19% primarily due to decreased sales of horticulture products, as order and delivery lead times for these products have normalized after volatility experienced in the previous year, and customers reduced their inventory levels and are beginning to return to normal seasonal buying patterns.

Cost of Products Sold decreased \$4.8 million primarily due to the combination of the following:

- Cost of products sold at BTD increased \$0.8 million primarily due to higher sales volumes, as discussed above. Cost of products sold also increased due to lower productivity and inflationary cost pressures which resulted in higher non-steel material, labor and overhead costs. The increase in labor costs and lower level of productivity was partially attributable to increased shift incentives and overtime wages combined with increased staffing levels to meet higher production volumes and the time required for new employees to achieve peak productivity. The impacts of higher sales volumes and increased labor and overhead costs were largely offset by decreased material costs, as discussed above.
- Cost of products sold at T.O. Plastics decreased \$5.6 million primarily due to lower sales volumes of horticulture products, as discussed above.

Selling, General, and Administrative Expenses increased \$7.2 million primarily due to increased employee compensation from an increase in headcount, inflationary cost pressure and variable compensation driven by current year financial performance.

Depreciation and Amortization increased \$2.3 million due to capital expenditures during the year, which included investments in facility improvements and purchases of equipment.

PLASTICS SEGMENT RESULTS

The following table summarizes the operating results for our Plastics segment for the years ended December 31, 2023 and 2022:

<i>(in thousands)</i>	2023	2022	\$ change	% change
Operating Revenues	\$ 418,026	\$ 512,527	\$ (94,501)	(18.4)%
Cost of Products Sold (excluding depreciation)	143,521	227,569	(84,048)	(36.9)
Selling, General, and Administrative Expenses	16,076	16,175	(99)	(0.6)
Depreciation and Amortization	4,027	4,205	(178)	(4.2)
Operating Income	\$ 254,402	\$ 264,578	\$ (10,176)	(3.8)%

Operating Revenues decreased \$94.5 million primarily due to a 14% decrease in sales volumes. Sales volume decreases were attributable to softer end market demand coupled with distributor inventory management, as these customers reduced their inventory levels during the first half of the year after previously building higher inventory levels in response to market uncertainty and supply chain challenges. Operating revenue decreases were also the result of a 5% decrease in sales prices, as prices in 2023 decreased from record highs in 2022.

Cost of Products Sold decreased \$84.0 million due to a 26% decrease in the cost per pound of PVC pipe sold, primarily due to lower resin costs, as well as the 14% decrease in sales volumes discussed above.

CORPORATE

The following table summarizes Corporate results of operations for the years ended December 31, 2023 and 2022:

<i>(in thousands)</i>		2023	2022	\$ change	% change
Selling, General, and Administrative Expenses	\$	12,042	\$ 16,202	\$ (4,160)	(25.7)%
Depreciation and Amortization		102	140	(38)	(27.1)
Operating Loss	\$	12,144	\$ 16,342	\$ (4,198)	(25.7)%

Selling, General, and Administrative Expenses decreased \$4.2 million primarily due to lower health care costs related to our self-funded health insurance program in 2023 compared to higher claim costs in 2022.

REGULATORY MATTERS

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

RATE CASES

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

<i>Jurisdiction</i>	<i>Implementation Date</i>	<i>Revenue Requirement (in millions)</i>	<i>Return on Rate Base</i>	<i>Allowed Return on Equity</i>	<i>Equity Ratio</i>
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%.

North Dakota Rate Case: On November 2, 2023, OTP filed a request with the NDPSC for an increase in revenue recoverable under general rates in North Dakota. In its filing, OTP requested a net increase in annual revenue of \$17.4 million, or 8.4%, based on an allowed rate of return on rate base of 7.85% and an allowed rate of return on equity of 10.6% on an equity ratio of 53.5% of total capital. Through this proceeding, OTP has proposed changes to the mechanism of cost and investment recovery, with recovery moving from riders into base rates. The filing also includes a proposal to implement a sales adjustment mechanism to address potential significant load additions or losses. The filing included an interim rate request of a net increase in annual revenue of \$12.4 million, or 6.0%, which was approved by the NDPSC on December 13, 2023, and interim rates went into effect on January 1, 2024. These interim rate revenues, when collected, are subject to potential refund until the finalization of the rate case.

RATE RIDERS

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

Recovery Mechanism	Jurisdiction	Status	Filing Date	Amount (in millions)	Effective Date	Notes
RRR - 2023	MN	Approved	11/01/22	\$17.5	07/01/23	Recovery of Hoot Lake Solar costs, Ashtabula III costs, and true up for PTCs from Merricourt.
ECO - 2023	MN	Approved	04/03/23	9.7	10/01/23	Recovery of energy conservation improvement costs as well as a demand side management financial incentive.
RRR - 2024	MN	Requested	12/04/23	8.0	07/01/24	Recovery of Hoot Lake Solar costs, Ashtabula III costs, wind upgrade project costs at our four owned wind facilities, and true up of PTCs for Merricourt.
RRR - 2023	ND	Approved	12/30/22	12.2	05/01/23	Recovery of Merricourt, Ashtabula III and other costs.
RRR - 2022	ND	Approved	01/05/22	7.8	04/01/22	Recovery of Merricourt costs, Ashtabula III costs, and deferred taxes and PTCs.
TCR - 2023	ND	Approved	09/15/22	7.5	01/01/23	Recovery of transmission project costs.
TCR - 2024	ND	Approved	11/02/23	4.5	01/01/24	Recovery of transmission project costs.
GCR - 2022	ND	Approved	03/01/22	3.3	07/01/22	Annual update to generation cost recovery rider.
MDT - 2023	ND	Approved	07/08/22	3.1	01/01/23	Recovery of advanced metering infrastructure, outage management system and demand response projects.
PIR - 2022	SD	Approved	06/01/22	3.0	09/01/22	Recovery of Ashtabula III, Merricourt, Astoria Station, Advanced Grid Infrastructure project costs, and impact of load growth credits.
TCR - 2023	SD	Approved	11/01/22	3.0	03/01/23	Recovery of transmission project costs.

RESOURCE PLANNING

On March 31, 2023, OTP submitted a supplemental resource plan filing to the MPUC, the NDPS, and the South Dakota Public Utilities Commission (SDPUC). The supplemental filing updated OTP’s original 2022 Integrated Resource Plan (2022 IRP), which was filed on September 1, 2021. In the supplemental filing, OTP outlined its updated plan for meeting all customers’ anticipated capacity and energy needs while maintaining system reliability and low electric service rates in light of several changes that had occurred since the original filing, including significant winter and spring reserve planning margins adopted by MISO, tax credits made available for renewable energy projects under the Inflation Reduction Act, the enactment of the Clean Energy Bill in Minnesota, and volatility experienced in energy and capacity markets.

On December 15, 2023, OTP submitted a second supplemental resource plan filing to the MPUC outlining an updated plan specifically for meeting Minnesota customers’ anticipated capacity and energy needs while maintaining system reliability and low electric service rates. Based on feedback received on the preferred plan outlined in the March 31, 2023 supplemental filing and the inability to reach a consensus on certain aspects of the plan, the second supplemental filing includes a proposal to bifurcate OTP’s resource planning by jurisdiction.

Under bifurcated resource planning, it is anticipated that OTP would develop two separate resource plans, one plan developed for Minnesota and a second developed for North Dakota and South Dakota. Each plan would be developed incorporating the assumption that all existing generation resources, except Hoot Lake Solar, would continue to be allocated to all jurisdictions using established jurisdictional allocators. Hoot Lake Solar is currently directly allocated to only Minnesota. As new generation resources are needed for each plan, those generation resources would be allocated to the jurisdiction that is needing the resource. To the extent a common generation resource is needed for both plans, that resource would be allocated using established jurisdictional allocators. This method of resource planning would diverge from OTP’s historical practice of planning on an integrated basis for all jurisdictions served.

With the proposal of bifurcated resource planning, the supplemental filing outlines OTP’s preferred plan for Minnesota only. The preferred plan in this supplemental filing includes:

- repowering four of our existing wind facilities in 2025;
- the addition of approximately 200 megawatts of solar generation in 2025;
- the addition of approximately 100 megawatts of wind generation in 2026;
- the addition of on-site liquefied natural gas fuel storage at our Astoria Station natural gas plant in 2027;
- the designation of Coyote Station, a jointly owned coal-fired generation plant, as an Available Maximum Emergency (AME) Resource beginning in 2029 and annually thereafter;
- a withdrawal from our 35 percent ownership interest in Coyote Station in the event we are required to make a major, non-routine capital investment in the plant; and
- the addition of approximately 50 megawatts of wind generation in 2032.

The preferred plan requests the MPUC issue an order requiring the Minnesota’s jurisdictionally allocated share of the generation from Coyote Station be designated as an AME Resource beginning March 1, 2029, subject to additional analysis to be performed by OTP. AME Resources are

resources called on only in the event of a maximum generation event, such as in the cases of extreme heat, cold, or other extreme events. Designating Coyote Station as an AME Resource would allow us to retain Coyote Station’s capacity, thereby providing an important reliability benefit. This also helps ensure we remain compliant with market monitoring regulations and our contractual obligations to the co-owners of Coyote Station while advancing our compliance with Minnesota's carbon-free standard. The supplemental filing requests Minnesota customer rates continue to include the recovery of an allocated share of OTP’s costs associated with owning the plant, and a return on those costs, as well as the fixed costs of operating the plant. The variable cost of operating the plant, which consists primarily of variable fuel costs, would not be attributed to Minnesota customers, except when the plant is called upon to serve Minnesota customers in emergency situations.

The supplemental IRP filing made December 15, 2023 outlines our proposed resource plan for Minnesota. We anticipate filing future resource plans on a bifurcated basis in North Dakota and South Dakota.

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, could 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, 2023, 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, 2023 and 2022:

<i>(in thousands)</i>	<i>Line Limit</i>	<i>2023</i>		<i>2022</i>	
		<i>Amount Outstanding</i>	<i>Letters of Credit</i>	<i>Amount Available</i>	<i>Amount Available</i>
OTC Credit Agreement	\$ 170,000	\$ —	\$ —	\$ 170,000	\$ 170,000
OTP Credit Agreement	170,000	81,422	9,132	79,446	152,223
Total	\$ 340,000	\$ 81,422	\$ 9,132	\$ 249,446	\$ 322,223

OTC and OTP are each party to separate credit agreements (the OTC Credit Agreement and OTP Credit Agreement, respectively) which provide for unsecured revolving lines of credit. Should additional liquidity be needed, the OTC Credit 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.

As of December 31, 2023, we had \$249.4 million of available liquidity under our credit facilities and \$230.4 million of available cash and cash equivalents, resulting in total available liquidity of \$479.8 million, compared to total available liquidity of \$441.2 million as of December 31, 2022.

CASH FLOWS

The following is a discussion of our cash flows for the years ended December 31, 2023 and 2022:

<i>(in thousands)</i>	<i>2023</i>	<i>2022</i>
Net Cash Provided by Operating Activities	\$ 404,499	\$ 389,309

Net Cash Provided by Operating Activities increased \$15.2 million primarily due to an increase in net income, the absence of any pension contribution in 2023 due to the plan's funded status, and the timing of customer collections of forecasted fuel costs, partially offset by increased working capital. Working capital increased primarily due to an increase in receivables in our Plastics segment, due to increased sales volumes in the fourth quarter of the current year, and a decrease in payables due to the timing of capital investment spending in our Electric segment and inventory purchases in our Plastics segment compared to last year.

Unique market dynamics experienced by our Plastics segment businesses in 2023 and 2022 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.

<i>(in thousands)</i>	<i>2023</i>	<i>2022</i>
Net Cash Used in Investing Activities	\$ 289,287	\$ 175,071

Net Cash Used in Investment Activities increased \$114.2 million primarily due to a higher amount of Electric segment capital investment compared to last year, including the purchase of the Ashtabula III wind farm, investments in our Hoot Lake Solar facility and several wind repowering projects, transmission and distribution asset investments, and investments in new technology. Capital expenditures in our Manufacturing and Plastics segments increased \$23.1 million as a result of investments in additional equipment and facility expansion projects at our Plastics segment facility in Arizona and our Manufacturing segment facility in Georgia.

<i>(in thousands)</i>	2023	2022
Net Cash Used in Financing Activities	\$ 3,835	\$ 96,779

Net Cash Used in Financing Activities decreased \$92.9 million primarily due to increased short-term borrowings on our OTP credit facility, which were primarily used to fund capital expenditures in our Electric segment, including the acquisition of the Ashtabula III wind farm. Our financing activities in 2023 included net short-term borrowings of \$73.2 million compared to net short-term repayments of \$83.0 million in 2022. There was no change in our long-term debt in 2023. In 2022, OTP issued \$60.0 million of long-term debt, net of retirements, which was primarily used to fund the repayment of short-term credit facility borrowings and fund capital expenditures. In 2023, we made dividend payments of \$73.1 million compared to \$68.8 million in 2022.

CAPITAL REQUIREMENTS

CAPITAL EXPENDITURES

Our capital expenditure plan includes investments in electric generation facilities, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, and computer hardware and information systems. Our capital expenditure plan 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, 2023 and 2022 for our Electric segment and non-electric businesses and anticipated capital expenditures for the five year period 2024 through 2028:

<i>(in millions)</i>	2022	2023	2024	2025	2026	2027	2028	Total
Electric Segment:								
Renewables			\$ 118	\$ 93	\$ 33	\$ 113	\$ 129	\$ 486
Transmission			51	85	111	98	100	445
Distribution			38	39	36	38	39	190
Other			67	37	30	27	25	186
Total Electric Segment	148	241	274	254	210	276	293	1,307
Manufacturing and Plastics Segments	23	46	79	35	27	25	26	192
Total Capital Expenditures	\$ 171	\$ 287	\$ 353	\$ 289	\$ 237	\$ 301	\$ 319	\$ 1,499

CONTRACTUAL OBLIGATIONS

The following table summarizes our contractual obligations at December 31, 2023 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

<i>(in millions)</i>	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Debt Obligations	\$ 908	\$ 81	\$ 80	\$ 42	\$ 705
Interest on Debt Obligations	602	35	70	62	435
Coal Contracts	485	24	49	52	360
Capacity and Energy Requirements	4	—	—	—	4
Postretirement Benefit Obligations	66	5	11	11	39
Other Purchase Obligations (including land easements)	79	6	9	5	59
Operating Lease Obligations	17	6	8	3	—
Total Contractual Cash Obligations	\$ 2,161	\$ 157	\$ 227	\$ 175	\$ 1,602

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 Lignite Sales Agreement (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 any contributions to that plan.

COMMON STOCK DIVIDENDS

We paid dividends to our shareholders totaling \$73.1 million, or \$1.75 per share, in 2023. The determination of the amount of future cash dividends to be paid will depend on, among other things, our financial condition, level of earnings and cash flows from operations, our capital expenditure plan 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 to OTC. These intercompany distributions serve as the primary source of funding for dividends paid to our shareholders. 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 5, 2024, our Board of Directors increased the quarterly dividend from \$0.4375 to \$0.4675 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 2024 through 2028 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, at which time we anticipate filing a new shelf registration statement. No shares were issued pursuant to the registration statement in 2023.

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 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, at which time we plan to file a new registration statement. In 2023, we issued 105,663 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, 2023, 1,145,330 shares remained available for purchase or issuance under the plan.

SHORT-TERM DEBT

The OTC Credit Agreement and OTP Credit Agreement provide for unsecured revolving lines of credit. 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, 2023 and 2022 was 6.70% and 5.61%.

The following is a summary of key provisions and borrowing information as of and for the year ended December 31, 2023:

<i>(in thousands, except interest rates)</i>	<i>OTC Credit Agreement</i>		<i>OTP Credit Agreement</i>	
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		—		9,132
Amount Outstanding at Year-End		—		81,422
Average Amount Outstanding During Year		—		50,883
Maximum Amount Outstanding During the Year		—		87,788
Interest Rate at Year-End		6.85 %		6.70 %
Expiration Date		October 29, 2027		October 29, 2027

¹Each 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, 2023, 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.

Financial Covenants

Certain of our short- and long-term debt agreements require OTC and OTP to maintain certain financial covenants. As of December 31, 2023, 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, 2023, our Interest-Bearing Debt to Total Capitalization was 0.39 to 1.00, our Interest and Dividend Coverage Ratio was 10.85 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, 2023, OTP's Interest-Bearing Debt to Total Capitalization was 0.46 to 1.00, its Interest and Dividend Coverage Ratio was 3.54 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, 2023 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	A-	n/a
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 sheets and recognize those amounts in the consolidated statement of income as an expense or income item, or in the consolidated statement of comprehensive income as a loss or gain item, in the period in which this accounting treatment is no longer applicable.

As of December 31, 2023 and 2022, we had regulatory assets of \$111.8 million and \$119.7 million and regulatory liabilities of \$302.0 million and \$261.8 million. If future recovery of amounts recorded as regulatory assets was no longer probable we would be required to recognize an expense or 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, 2023, we set the discount rate used to measure our pension plan obligations at 5.57% and at 5.53% to measure postretirement healthcare obligations, a six and one basis point increase, respectively, from the estimates used at December 31, 2022. Our estimates used to determine benefit cost for 2023 included a discount rate of 5.51% for pension benefits and 5.52% for postretirement healthcare costs, a 248 and 251 basis point increase, respectively, from 2022 estimates. The 5.52% discount rate for postretirement healthcare costs was adjusted to 6.06% effective September 30, 2023, in connection with a remeasurement of our plan liability due to an amendment to the plan. The adjustment to 6.06% was a 305 basis point increase from the 2022 estimate. In addition, we estimated our assumed rate of return on pension assets to be 7.00% for 2023, a 70 basis point increase from our 2022 estimate.

The following table summarizes the impact on 2023 pension and postretirement costs for a 25 basis point increase or decrease, holding all other variables constant, on certain key assumptions:

<i>(in thousands)</i>	+0.25	-0.25
Pension Plan:		
Discount Rate	\$ 65	\$ (72)
Rate of Increase in Future Compensation	259	245
Long-Term Return on Plan Assets	(926)	926
Other Postretirement Benefits:		
Discount Rate	13	3

For 2024, we expect pension and other postretirement benefit income to be \$8.5 million compared to \$9.5 million of income in 2023, due to the impacts of updated actuarial assumptions. See additional information at footnote 10 of the consolidated financial statements.

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 earnings before interest, taxes, depreciation, and amortization (EBITDA), 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 2023 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 include an inherent 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, 2023, OTP was party to financial swap agreements with an aggregate notional amount of 187,400 megawatt-hours of electricity with various settlement dates throughout 2024. As of December 31, 2023, the aggregate fair value of these instruments was \$4.2 million, reflected as a liability on our consolidated balance sheets. Holding other variables constant, a ten percent change in energy prices would have had an approximate \$0.7 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 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 our outstanding short-term debt which is subject to variable rates of interest based on benchmark interest rates, primarily SOFR, and our cash equivalent investments, which earn income at a rate that fluctuates daily, based on changes in U.S. treasury rates. As of December 31, 2023 and 2022, we had \$81.4 million and \$8.2 million of short-term debt outstanding. Holding other variables constant, a 100 basis point change in interest rates during 2023 would have had an approximate \$0.5 million impact to interest expense in 2023 based on our average outstanding short-term debt during the year. As of December 31, 2023 and 2022, we had \$219.7 million and \$105.8 million invested in cash equivalent investments. Holding other variables constant, a 100 basis point change in the average interest rates during 2023 would have had an approximate \$1.5 million impact to our investment income in 2023 based on our average outstanding investment balance during the year.

All of our outstanding long-term debt obligations as of December 31, 2023 and 2022 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, 2023 and 2022, 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, 2023, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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, 2023, 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 Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matter

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

Regulatory 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 regulation of rates and other matters 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.

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 the recording of regulatory assets for certain costs which otherwise would be recognized in the statement of income or comprehensive income based on an expectation that the costs will be recovered in future rates and the recording of regulatory liabilities 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. Given that management's accounting judgements are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

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

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred 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 regulatory assets or liabilities, 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, and the related disclosures in the notes to the financial statements.
- 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 interveners, 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 obtained an analysis from management 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 14, 2024

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

OTTER TAIL CORPORATION
CONSOLIDATED BALANCE SHEETS

<i>(in thousands, except share data)</i>	<i>December 31,</i>	
	2023	2022
Assets		
Current Assets		
Cash and Cash Equivalents	\$ 230,373	\$ 118,996
Receivables, net of allowance for credit losses	157,143	144,393
Inventories	149,701	145,952
Regulatory Assets	16,127	24,999
Other Current Assets	16,826	18,412
Total Current Assets	570,170	452,752
Noncurrent Assets		
Investments	62,516	54,845
Property, Plant and Equipment, net of accumulated depreciation	2,418,375	2,212,717
Regulatory Assets	95,715	94,655
Intangible Assets, net of accumulated amortization	6,843	7,943
Goodwill	37,572	37,572
Other Noncurrent Assets	51,377	41,177
Total Noncurrent Assets	2,672,398	2,448,909
Total Assets	\$ 3,242,568	\$ 2,901,661
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-Term Debt	\$ 81,422	\$ 8,204
Accounts Payable	94,428	104,400
Accrued Salaries and Wages	38,134	32,327
Accrued Taxes	26,590	19,340
Regulatory Liabilities	25,408	17,300
Other Current Liabilities	43,775	56,065
Total Current Liabilities	309,757	237,636
Noncurrent Liabilities and Deferred Credits		
Pension Benefit Liability	33,101	33,210
Other Postretirement Benefits Liability	27,676	46,977
Regulatory Liabilities	276,547	244,497
Deferred Income Taxes	237,273	221,302
Deferred Tax Credits	15,172	15,916
Other Noncurrent Liabilities	75,977	60,985
Total Noncurrent Liabilities and Deferred Credits	665,746	622,887
Commitments and Contingencies (Note 13)		
Capitalization		
Long-Term Debt	824,059	823,821
Shareholders' Equity		
Common Stock: 50,000,000 shares authorized of \$5 par value; 41,710,521 and 41,631,113 outstanding at December 31, 2023 and 2022	208,553	208,156
Additional Paid-In Capital	426,963	423,034
Retained Earnings	806,342	585,212
Accumulated Other Comprehensive Income	1,148	915
Total Shareholders' Equity	1,443,006	1,217,317
Total Capitalization	2,267,065	2,041,138
Total Liabilities and Shareholders' Equity	\$ 3,242,568	\$ 2,901,661

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

<i>(in thousands, except per-share amounts)</i>	<i>Years Ended December 31,</i>		
	2023	2022	2021
Operating Revenues			
Electric	\$ 528,359	\$ 549,699	\$ 480,321
Product Sales	820,807	910,510	716,523
Total Operating Revenues	1,349,166	1,460,209	1,196,844
Operating Expenses			
Electric Production Fuel	60,339	65,110	59,327
Electric Purchased Power	78,292	100,281	65,409
Electric Operating and Maintenance Expenses	191,263	181,378	159,669
Cost of Products Sold (excluding depreciation)	454,122	542,944	488,370
Nonelectric Selling, General, and Administrative Expenses	72,663	69,718	65,394
Depreciation and Amortization	97,954	92,597	91,358
Electric Property Taxes	16,614	17,742	17,609
Total Operating Expenses	971,247	1,069,770	947,136
Operating Income	377,919	390,439	249,708
Other Income and Expense			
Interest Expense	(37,677)	(36,016)	(37,771)
Nonservice Cost Components of Postretirement Benefits	10,597	1,075	(2,016)
Other Income (Expense), net	12,650	2,037	2,900
Income Before Income Taxes	363,489	357,535	212,821
Income Tax Expense	69,298	73,351	36,052
Net Income	\$ 294,191	\$ 284,184	\$ 176,769
Weighted-Average Common Shares Outstanding:			
Basic	41,668	41,586	41,491
Diluted	42,039	41,931	41,818
Earnings Per Share:			
Basic	\$ 7.06	\$ 6.83	\$ 4.26
Diluted	\$ 7.00	\$ 6.78	\$ 4.23

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	2023	2022	2021
Net Income	\$ 294,191	\$ 284,184	\$ 176,769
Other Comprehensive Income (Loss):			
Unrealized Gain (Loss) on Available-for-Sale Securities, net of tax (expense) benefit of \$(51), \$115 and \$52	192	(432)	(196)
Pension and Other Postretirement Benefit Plan, net of tax expense of \$14, \$2,769 and \$766	41	7,871	2,179
Total Other Comprehensive Income	233	7,439	1,983
Total Comprehensive Income	\$ 294,424	\$ 291,623	\$ 178,752

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

<i>(in thousands, except common stock outstanding)</i>	<i>Common Stock Outstanding</i>	<i>Par Value, Common Stock</i>	<i>Additional Paid-In Capital</i>	<i>Retained Earnings</i>	<i>Accumulated Other Comprehensive Income (Loss)</i>	<i>Total Shareholders' Equity</i>
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
Employee Stock Purchase Plan Expenses	—	—	(339)	—	—	(339)
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	79,408	397	(3,485)	—	—	(3,088)
Net Income	—	—	—	294,191	—	294,191
Other Comprehensive Income	—	—	—	—	233	233
Stock Compensation Expense	—	—	7,753	—	—	7,753
Common Dividends (\$1.75 per share)	—	—	—	(73,061)	—	(73,061)
Balance, December 31, 2023	41,710,521	\$ 208,553	\$ 426,963	\$ 806,342	\$ 1,148	\$ 1,443,006

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	2023	2022	2021
Operating Activities			
Net Income	\$ 294,191	\$ 284,184	\$ 176,769
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	97,954	92,597	91,358
Deferred Tax Credits	(744)	(745)	(744)
Deferred Income Taxes	13,508	32,424	28,896
Discretionary Contribution to Pension Plan	—	(20,000)	(10,000)
Investment (Gains) Losses	(7,222)	3,296	(4,524)
Stock Compensation Expense	7,753	6,814	6,908
Other, net	(423)	(1,473)	667
Changes in Operating Assets and Liabilities:			
Receivables	(12,750)	30,560	(60,994)
Inventories	(2,450)	5,339	(54,313)
Regulatory Assets	12,479	(2,464)	(4,803)
Other Assets	2,817	(368)	(14,146)
Accounts Payable	(9,988)	(29,763)	38,734
Accrued and Other Liabilities	6	(5,490)	28,386
Regulatory Liabilities	20,973	(6,846)	1,948
Pension and Other Postretirement Benefits	(11,605)	1,244	7,101
Net Cash Provided by Operating Activities	404,499	389,309	231,243
Investing Activities			
Capital Expenditures	(287,134)	(171,134)	(171,829)
Proceeds from Disposal of Noncurrent Assets	6,225	4,346	9,702
Purchases of Investments and Other Assets	(8,378)	(8,283)	(9,383)
Net Cash Used in Investing Activities	(289,287)	(175,071)	(171,510)
Financing Activities			
Net Borrowings (Repayments) on Short-Term Debt	73,218	(82,959)	10,166
Proceeds from Issuance of Common Stock	—	—	696
Proceeds from Issuance of Long-Term Debt	—	90,000	140,000
Payments for Retirement of Long-Term Debt	—	(30,000)	(140,169)
Dividends Paid	(73,061)	(68,755)	(64,864)
Payments for Shares Withheld for Employee Tax Obligations	(3,088)	(2,942)	(1,507)
Other, net	(904)	(2,123)	(3,681)
Net Cash Used in Financing Activities	(3,835)	(96,779)	(59,359)
Net Change in Cash and Cash Equivalents	111,377	117,459	374
Cash and Cash Equivalents at Beginning of Period	118,996	1,537	1,163
Cash and Cash Equivalents at End of Period	\$ 230,373	\$ 118,996	\$ 1,537
Supplemental Disclosures of Cash Flow Information			
Cash Paid During the Year for:			
Interest, net of amount capitalized	\$ 36,956	\$ 35,699	\$ 36,881
Income Taxes	\$ 46,284	\$ 43,411	\$ 8,445
Supplemental Disclosure of Noncash Investing Activities			
Accrued Property, Plant and Equipment Additions	\$ 13,001	\$ 12,420	\$ 12,081

See accompanying notes to consolidated financial statements

OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Overview

Otter Tail Corporation (OTC) 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.

Reclassifications

Certain reclassifications of amounts previously reported have been made to the accompanying consolidated statements of cash flows to maintain consistency and comparability between periods presented. Other, net operating cash flows previously reported for the years ended December 31, 2022 and 2021, included \$3.3 million of investment losses and \$4.5 million of investment gains, respectively, which are presented separately in the current year, and excluded \$1.7 million and \$0.8 million of allowance for equity funds used during construction (AFUDC), which were previously presented separately. The reclassifications had no impact on previously reported net cash provided by operating activities, net cash used in investing activities, net cash used in financing activities, or cash and cash equivalents. Certain prior period amounts related to deferred tax assets and deferred tax liabilities included in footnote 12 have been reclassified to conform to the current year presentation.

Regulatory Accounting

Our regulated electric utility company, Otter Tail Power Company (OTP), 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 sheets and included in the consolidated statement of income as an expense or income item, or in the consolidated statement of comprehensive income as a loss or gain item, in the period in which the application of this guidance ceases.

Cash Equivalents

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

Concentration of Deposits

We hold deposits with financial institutions which potentially subject us to a concentration risk. These deposits are guaranteed by the Federal Deposit Insurance Corporation up to an insurance limit of \$250,000. Currently, our cash deposits exceed federally insured levels.

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 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 products 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 amount 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 and products to customers across several industries and 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 free on board (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 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, 2023 and 2022:

<i>(in thousands)</i>	2023		2022	
Finished Goods	\$	47,614	\$	43,812
Work in Process		26,354		31,766
Raw Material, Fuel and Supplies		75,733		70,374
Total Inventories	\$	149,701	\$	145,952

Investments

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

We hold debt, mutual fund, and money market fund investments either as investments within our captive insurance entity or to provide future funding for obligations under nonqualified 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, 2023 and 2022:

<i>(in thousands)</i>	2023		2022	
Corporate-Owned Life Insurance Policies	\$	42,287	\$	38,991
Corporate and Government Debt Securities		9,303		8,761
Mutual Funds		7,771		5,503
Money Market Funds		3,125		1,560
Other Investments		30		30
Total Investments	\$	62,516	\$	54,845

The amount of unrealized gains and losses on debt securities as of December 31, 2023 and 2022 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, 2023 and 2022 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 AFUDC. The amount of interest capitalized to electric plant was \$1.9 million in 2023, \$0.9 million in 2022 and \$0.6 million in 2021. 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 recorded to accumulated depreciation 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 2023, 2022 or 2021. 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:

<i>(years)</i>	Service Life Range	
	Low	High
Electric Assets:		
Production Plant	21	114
Transmission Plant	51	75
Distribution Plant	10	70
General Plant	5	56
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.

Cloud Computing Costs

We capitalize implementation costs incurred in cloud computing arrangements that are service contracts consistent with capitalized implementation costs incurred to develop or obtain internal-use software. Costs are amortized on a straight-line basis over the life of the associated contract. Capitalized implementation costs are amortized over periods up to ten years. Capitalized costs and related accumulated amortization are included in other noncurrent assets on the consolidated balance sheets. Below are the amounts of capitalized cost and related accumulated amortization as of December 31, 2023 and 2022:

<i>(in thousands)</i>	2023		2022	
Cloud Computing Costs	\$	12,782	\$	9,024
Accumulated Amortization	\$	(1,505)	\$	(897)
Cloud Computing Costs, net	\$	11,277	\$	8,127

Amortization expense of capitalized implementation costs for each of the years ended December 31, 2023, 2022 and 2021 totaled \$1.3 million, \$1.4 million, and \$0.5 million.

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 have elected to account for transferable tax credits as a component of our income tax provision. We recognize the benefit of PTCs as a reduction of income tax expense in the period the credit is generated, which corresponds to the period the energy production occurs. 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.

Deferred Compensation Plans

The Company sponsors two nonqualified deferred compensation plans for the benefit of executive officers and other select employees. Each plan allows participants to defer a specified amount or percentage of base wages or incentive compensation into the plan, subject to certain limitations. The Company, at its discretion, may make employer contributions to either plan during any annual period. Participant and employer deferred amounts are segregated into one or more accounts chosen by the participant. Participants earn a return on deferred amounts based on notional investments in the segregated accounts. Participants can elect lump sum distributions or annual installments of deferred balances during the participant's employment or upon retirement. As of December 31, 2023 and 2022, our liability to participants under these deferred compensation plans was \$24.6 million and \$20.6 million. Company contributions to these plans were \$1.2 million, \$0.9 million and \$1.1 million for the years ended December 31, 2023, 2022 and 2021. Gains or (losses) recognized due to changes in our payment obligations in connection with these plans amounted to (\$3.3 million), \$3.1 million, and (\$2.2 million) for the years ended December 31, 2023, 2022 and 2021.

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.

Related Parties

The Otter Tail Corporation Foundation and Otter Tail Power Company Foundation are independent not-for-profit charitable entities affiliated with the Company and are not included in the consolidated financial statements of Otter Tail Corporation. Contribution obligations to the two foundations totaling \$5.5 million and \$4.3 million were recognized as of December 31, 2023 and 2022. Cash contributions paid to the two foundations during the years ended December 31, 2023, 2022 and 2021 were \$4.3 million, \$4.5 million, and \$3.8 million.

Variable Interest Entity

In October 2012, the Coyote Station owners, including OTP, entered into an LSA with Coyote Creek Mining Company, LLC, 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 the 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 \$40 million, or OTP's 35% share of CCMC's unrecovered costs as of December 31, 2023, if recovery of such a loss is denied by regulatory authorities.

Recent Accounting Pronouncements

Segment Reporting. In November 2023, the Financial Accounting Standards Board (FASB) issued amended authoritative guidance codified in Accounting Standards Codification (ASC) 280, Segment Reporting. The amended guidance expands annual and interim disclosure requirements for reportable segments, primarily through expanded disclosures about significant segment expenses. The updated standard is effective for our annual periods beginning in 2024 and interim periods beginning in the first quarter of fiscal 2025. Adoption of the amended guidance must be applied retrospectively to all prior periods presented in the financial statements. We are currently evaluating the impact that the updated standard will have on our financial statement disclosures.

Income Taxes. In December 2023, the FASB issued amended authoritative guidance codified in ASC 740, Income Taxes. The amended guidance requires additional disaggregated information in effective tax rate reconciliation disclosures and additional disaggregated information about income taxes paid. The updated standard is effective for our annual periods beginning in 2025. The amended guidance is to be applied on a prospective basis with the option to apply the standard retrospectively. We are currently evaluating the impact that the updated standard will have on our financial statement disclosures.

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, income and expenses are not allocated to our operating segments. Corporate operating results include items such as corporate staff and overhead costs, the results of our captive insurance company, gains or losses on our investments and returns on our cash equivalent investments. These items and others are excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, investments, prepaid expenses, 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, 2023, 2022 and 2021 are as follows:

<i>(in thousands)</i>	2023		2022		2021	
Operating Revenue						
Electric	\$	528,359	\$	549,699	\$	480,321
Manufacturing		402,781		397,983		336,294
Plastics		418,026		512,527		380,229
Total		1,349,166		1,460,209		1,196,844
Depreciation and Amortization						
Electric		75,330		72,050		71,343
Manufacturing		18,495		16,202		15,436
Plastics		4,027		4,205		4,354
Corporate		102		140		225
Total		97,954		92,597		91,358
Operating Income (Loss)						
Electric		106,521		113,138		106,964
Manufacturing		29,140		29,065		24,114
Plastics		254,402		264,578		132,760
Corporate		(12,144)		(16,342)		(14,130)
Total		377,919		390,439		249,708
Interest Expense						
Electric		33,864		31,950		33,043
Manufacturing		2,295		2,796		2,239
Plastics		602		585		587
Corporate		916		685		1,902
Total		37,677		36,016		37,771
Income Tax Expense (Benefit)						
Electric		1,648		5,065		1,663
Manufacturing		5,390		5,321		4,704
Plastics		66,066		68,688		34,374
Corporate		(3,806)		(5,723)		(4,689)
Total		69,298		73,351		36,052
Net Income (Loss)						
Electric		84,424		79,974		72,458
Manufacturing		21,454		20,950		17,186
Plastics		187,748		195,374		97,823
Corporate		565		(12,114)		(10,698)
Total		294,191		284,184		176,769
Capital Expenditures						
Electric		240,695		147,869		140,031
Manufacturing		23,284		17,954		20,690
Plastics		23,029		5,245		11,040
Corporate		126		66		68
Total	\$	287,134	\$	171,134	\$	171,829

The following provides the identifiable assets by segment and corporate assets as of December 31, 2023 and 2022:

<i>(in thousands)</i>	2023		2022	
Identifiable Assets				
Electric	\$	2,533,831	\$	2,351,961
Manufacturing		251,343		245,869
Plastics		164,179		126,318
Corporate		293,215		177,513
Total	\$	3,242,568	\$	2,901,661

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 2023, we sourced all of our PVC resin needs from three 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, 2023, 2022 and 2021. 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, 2023, 2022 and 2021:

<i>(in thousands)</i>	2023	2022	2021
Operating Revenues			
Electric Segment			
Retail: Residential	\$ 135,570	\$ 143,888	\$ 135,361
Retail: Commercial and Industrial	312,551	318,494	262,408
Retail: Other	7,719	7,918	7,715
Total Retail	455,840	470,300	405,484
Transmission	52,555	52,213	48,835
Wholesale	12,459	18,539	17,936
Other	7,505	8,647	8,066
Total Electric Segment	528,359	549,699	480,321
Manufacturing Segment			
Metal Parts and Tooling	351,267	338,865	283,527
Plastic Products and Tooling	41,395	49,080	40,231
Scrap Metal	10,119	10,038	12,536
Total Manufacturing Segment	402,781	397,983	336,294
Plastics Segment			
PVC Pipe	418,026	512,527	380,229
Total Operating Revenue	1,349,166	1,460,209	1,196,844
Less: Noncontract Revenues Included Above			
Electric Segment - ARP Revenues	(4,310)	(9,266)	(791)
Total Operating Revenues from Contracts with Customers	\$ 1,353,476	\$ 1,469,475	\$ 1,197,635

4. Receivables

Receivables as of December 31, 2023 and 2022 are as follows:

<i>(in thousands)</i>	2023	2022
Receivables		
Trade	\$ 129,257	\$ 112,126
Other	9,084	9,983
Unbilled Receivables	21,324	23,932
Total Receivables	159,665	146,041
Less Allowance for Credit Losses	2,522	1,648
Receivables, net of allowance for credit losses	\$ 157,143	\$ 144,393

The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2023 and 2022:

<i>(in thousands)</i>	2023		2022	
Beginning Balance	\$	1,648	\$	1,836
Additions Charged to Expense		2,014		909
Reductions for Amounts Written Off, Net of Recoveries		(1,140)		(1,097)
Ending Balance	\$	2,522	\$	1,648

5. Regulatory Matters

Regulatory Assets and Liabilities

The following presents our current and long-term regulatory assets and liabilities as of December 31, 2023 and 2022 and the period we expect to recover or refund such amounts:

<i>(in thousands)</i>	<i>Period of Recovery/Refund</i>	2023		2022	
		<i>Current</i>	<i>Long-Term</i>	<i>Current</i>	<i>Long-Term</i>
Regulatory Assets					
Pension and Other Postretirement Benefit Plans ¹	See below	\$ 154	\$ 86,134	\$ —	\$ 88,354
Alternative Revenue Program Riders ²	Up to 2 years	3,719	158	5,679	2,508
Asset Retirement Obligations ¹	Asset lives	—	87	—	1,467
Deferred Income Taxes	Asset lives	—	6,940	—	—
Fuel Clause Adjustments ¹	Up to 1 year	7,294	—	10,893	—
Derivative Instruments ¹	Up to 1 year	4,210	—	7,130	—
Other ¹	Various	750	2,396	1,297	2,326
Total Regulatory Assets		16,127	95,715	24,999	94,655
Regulatory Liabilities					
Deferred Income Taxes	Asset lives	—	136,022	—	131,480
Plant Removal Obligations	Asset lives	—	117,030	8,509	105,733
Fuel Clause Adjustments	Up to 1 year	11,350	—	365	—
Alternative Revenue Program Riders	Up to 1 year	6,885	—	2,504	—
North Dakota PTC Refunds	Asset lives	—	12,011	—	7,136
Pension and Other Postretirement Benefit Plans	See below	6,138	11,307	5,589	—
Other	Various	1,035	177	333	148
Total Regulatory Liabilities		\$ 25,408	\$ 276,547	\$ 17,300	\$ 244,497

¹Costs subject to recovery without a rate of return.

²Amount 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.

Fuel Clause Adjustments represent the under- or over-collection of fuel costs relative to the estimated cost of fuel included in customer rates, which will be collected from or returned to customers.

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.

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.

North Dakota PTC Refunds represent PTCs earned from the Merricourt Wind Energy Center. These amounts are being allocated to customers over the life of the asset.

Other regulatory assets and liabilities include other amounts that we expect to recover from, or return to, customers in future periods, such as

the cost of abandoned projects, costs incurred in connection with recent rate cases, and other items.

North Dakota Rate Case

On November 2, 2023, OTP filed a request with the NDPSC for an increase in revenue recoverable under general rates in North Dakota. In its filing, OTP requested a net increase in annual revenue of \$17.4 million, or 8.4%, based on an allowed rate of return on rate base of 7.85% and an allowed rate of return on equity of 10.6% on an equity ratio of 53.5% of total capital. Through this proceeding, OTP has proposed changes to the mechanism of cost and investment recovery, with recovery moving from riders into base rates. The filing also includes a proposal to implement a sales adjustment mechanism to address potential significant load additions or losses. The filing included an interim rate request of a net increase in annual revenue of \$12.4 million, or 6.0%, which was approved by the NDPSC on December 13, 2023, and interim rates went into effect on January 1, 2024. These interim rate revenues, when collected, are subject to potential refund until the finalization of the rate case.

6. Property, Plant and Equipment

Major classes of property, plant and equipment as of December 31, 2023 and 2022 include:

<i>(in thousands)</i>	2023	2022
Electric Plant in Service		
Production	\$ 1,412,826	\$ 1,343,097
Transmission	777,613	756,848
Distribution	654,704	612,716
General	144,738	131,718
Electric Plant in Service	2,989,881	2,844,379
Construction Work in Progress	137,212	113,932
Total Gross Electric Plant	3,127,093	2,958,311
Less Accumulated Depreciation and Amortization	851,148	859,988
Net Electric Plant	2,275,945	2,098,323
Nonelectric Property, Plant and Equipment		
Equipment	233,571	218,770
Buildings and Leasehold Improvements	64,753	61,506
Land	13,600	13,652
Nonelectric Property, Plant and Equipment	311,924	293,928
Construction Work in Progress	38,062	15,170
Total Gross Nonelectric Property, Plant and Equipment	349,986	309,098
Less Accumulated Depreciation and Amortization	207,556	194,704
Net Nonelectric Property, Plant and Equipment	142,430	114,394
Net Property, Plant and Equipment	\$ 2,418,375	\$ 2,212,717

Depreciation expense for the years ended December 31, 2023, 2022 and 2021 totaled \$90.8 million, \$84.4 million and \$85.8 million.

The following table provides OTP's ownership percentages and amounts included in the December 31, 2023 and 2022 consolidated balance sheets for OTP's share of each of these jointly owned facilities:

<i>(dollars in thousands)</i>	<i>Ownership Percentage</i>	<i>Electric Plant in Service</i>	<i>Construction Work in Progress</i>	<i>Accumulated Depreciation</i>	<i>Net Plant</i>
December 31, 2023					
Big Stone Plant	53.9 %	\$ 341,683	\$ 820	\$ (126,904)	\$ 215,599
Coyote Station	35.0 %	188,656	104	(115,306)	73,454
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(7,181)	99,004
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(11,238)	66,946
Big Stone South–Brookings 345 kV line	50.0 %	53,170	—	(5,207)	47,963
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,409	83	(3,617)	22,875
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,568)	12,763
Jamestown– Ellendale 345 kV line	50.0 %	—	1,121	—	1,121
Big Stone South–Alexandria 345 kV line	40.0 %	—	555	—	555
Alexandria–Big Oaks 345 kV line	14.2 %	—	343	—	343
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

7. Intangible Assets

The following table summarizes our goodwill by segment as of December 31, 2023 and 2022:

<i>(in thousands)</i>	<i>2023</i>	<i>2022</i>
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 2023 and 2022, indicated no impairment existed as of the test date.

The following table summarizes the components of our intangible assets at December 31, 2023 and 2022:

<i>(in thousands)</i>	<i>Gross Amount</i>	<i>Accumulated Amortization</i>	<i>Net Carrying Amount</i>
December 31, 2023			
Customer Relationships	\$ 22,491	\$ 15,667	\$ 6,824
Other	26	7	19
Total	22,517	15,674	6,843
December 31, 2022			
Customer Relationships	22,491	14,568	7,923
Other	26	6	20
Total	\$ 22,517	\$ 14,574	\$ 7,943

Amortization expense for these intangible assets for each of the years ended December 31, 2023, 2022 and 2021 totaled \$1.1 million.

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

<i>(in thousands)</i>	<i>2024</i>	<i>2025</i>	<i>2026</i>	<i>2027</i>	<i>2028</i>
Amortization Expense	\$ 1,100	\$ 1,100	\$ 1,092	\$ 1,090	\$ 554

8. Leases

We lease rail cars, warehouse and office space, land, and certain office, manufacturing, material handling, and other 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, 2023, 2022, and 2021 are as follows:

<i>(in thousands)</i>	2023	2022	2021
Lease Cost			
Operating Lease Cost	\$ 6,309	\$ 5,606	\$ 5,298
Variable Lease Cost	1,433	1,386	1,020
Short-Term Lease Cost	2,525	1,517	1,465
Total Lease Cost	10,267	8,509	7,783
Lease Cash Flows			
Operating Cash Flows from Operating Leases	\$ 6,424	\$ 5,592	\$ 5,642

A summary of operating lease right-of-use lease assets and lease liabilities as of December 31, 2023 and 2022 is as follows:

<i>(in thousands)</i>	2023	2022
Right of Use Lease Assets ¹	\$ 16,788	\$ 18,610
Lease Liabilities		
Current ²	5,756	5,071
Long-Term ³	11,258	13,876
Total Lease Liabilities	\$ 17,014	\$ 18,947

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

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

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

Operating lease assets obtained in exchange for new operating liabilities amounted to \$3.6 million and \$3.7 million for the years ended December 31, 2023 and 2022.

Maturities of lease liabilities as of December 31, 2023 for each of the next five years and in the aggregate thereafter are as follows:

<i>(in thousands)</i>	Operating Leases
2024	\$ 6,473
2025	5,357
2026	3,068
2027	2,196
2028	1,059
Thereafter	368
Total Lease Payments	18,521
Less: Interest	1,507
Present Value of Lease Liabilities	\$ 17,014

The weighted-average remaining lease term and the weighted-average discount rate as of December 31, 2023 and 2022 are as follows:

	2023	2022
Weighted-Average Remaining Lease Term (in years)	3.4	4.2
Weighted-Average Discount Rate	5.40 %	4.73 %

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, 2023 and 2022:

<i>(in thousands)</i>	2023			2022		
	OTC	OTP	Total	OTC	OTP	Total
Short-Term Debt	\$ —	\$ 81,422	\$ 81,422	\$ —	\$ 8,204	\$ 8,204
Current Maturities of Long-Term Debt	—	—	—	—	—	—
Long-Term Debt, net of current maturities	79,849	744,210	824,059	79,798	744,023	823,821
Total	\$ 79,849	\$ 825,632	\$ 905,481	\$ 79,798	\$ 752,227	\$ 832,025

Short-Term Debt

The following is a summary of our lines of credit as of December 31, 2023 and 2022:

<i>(in thousands)</i>	Line Limit	2023		2022	
		Amount Outstanding	Letters of Credit	Amount Available	Amount Available
OTC Credit Agreement	\$ 170,000	\$ —	\$ —	\$ 170,000	\$ 170,000
OTP Credit Agreement	170,000	81,422	9,132	79,446	152,223
Total	\$ 340,000	\$ 81,422	\$ 9,132	\$ 249,446	\$ 322,223

OTC is party to a Fifth Amended and Restated Credit Agreement (the OTC Credit Agreement) and OTP is party to a Fourth Amended and Restated Credit Agreement (the OTP Credit Agreement). 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, 2023 and 2022 was 6.70% and 5.61%.

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. Each credit facility expires on October 29, 2027.

Long-Term Debt

The following is a summary of outstanding long-term debt by borrower as of December 31, 2023 and 2022:

Entity	Debt Instrument	Rate	Maturity	(in thousands)	
				2023	2022
OTC	Guaranteed Senior Notes	3.55%	12/15/26	\$ 80,000	\$ 80,000
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	90,000
Total				827,000	827,000
	Less: Unamortized Long-Term Debt Issuance Costs			2,941	3,179
	Total Long-Term Debt Net of Unamortized Debt Issuance Costs			\$ 824,059	\$ 823,821

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 borrower, 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, 2023 for each of the next five years are as follows:

(in thousands)	2024	2025	2026	2027	2028
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, 2023, OTC and OTP were in compliance with these financial covenants.

Guaranties

OTC's obligations under the terms of its Guaranteed Senior Notes are unconditionally and irrevocably guaranteed by its subsidiaries, Varistar Corporation, BTM Manufacturing, Inc., Northern Pipe Products, Inc., and Vinyltech Corporation.

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, 2023 and 2022:

<i>Asset Class</i>	Permitted Range	Actual Allocation	
		2023	2022
Return Enhancement	35 – 60%	48 %	48 %
Risk Management	40 – 80%	51	51
Alternatives	0 – 20%	1	1
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, 2023 and 2022 and assets measured using the net asset value (NAV) practical expedient:

<i>(in thousands)</i>	<i>Level 1</i>	<i>Level 2</i>	<i>Level 3</i>	<i>NAV</i>	<i>Total</i>
December 31, 2023					
Equity Funds	\$ 127,159	\$ —	\$ —	\$ —	\$ 127,159
Fixed Income Funds	167,604	—	—	—	167,604
Hybrid Funds	10,980	—	—	—	10,980
U.S. Treasury Securities	23,218	—	—	—	23,218
SEI Energy Debt Collective Fund	—	—	—	1,518	1,518
Total	328,961	—	—	1,518	330,479
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	19,587	—	—	—	19,587
SEI Energy Debt Collective Fund	—	—	—	3,703	3,703
Total	\$ 310,094	\$ —	\$ —	\$ 3,703	\$ 313,797

The investments held by the SEI Energy Debt Collective Fund on December 31, 2023 and 2022 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, 2023 and 2022 and the funded status of the plans as of December 31, 2023 and 2022:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	2023	2022	2023	2022	2023	2022
Change in Fair Value of Plan Assets:						
Fair Value of Plan Assets at January 1	\$ 313,797	\$ 387,212	\$ —	\$ —	\$ —	\$ —
Actual Return on Plan Assets	34,196	(76,485)	—	—	—	—
Company Contributions	—	20,000	2,197	2,205	3,167	2,294
Benefit Payments	(17,514)	(16,930)	(2,197)	(2,205)	(8,900)	(8,173)
Participant Premium Payments	—	—	—	—	5,733	5,879
Fair Value of Plan Assets at December 31	330,479	313,797	—	—	—	—
Change in Benefit Obligation:						
Benefit Obligation at January 1	308,055	416,697	35,624	46,840	49,947	69,311
Service Cost	3,698	6,576	72	195	565	1,338
Interest Cost	16,436	12,344	1,889	1,341	2,416	2,041
Benefit Payments	(17,514)	(16,930)	(2,197)	(2,205)	(8,900)	(8,172)
Participant Premium Payments	—	—	—	—	5,733	5,879
Plan Amendments	—	—	—	—	(17,493)	—
Actuarial (Gain) Loss	8,126	(110,632)	392	(10,547)	(2,123)	(20,450)
Benefit Obligation at December 31	318,801	308,055	35,780	35,624	30,145	49,947
Funded Status	\$ 11,678	\$ 5,742	\$ (35,780)	\$ (35,624)	\$ (30,145)	\$ (49,947)
Amounts Recognized in Consolidated Balance Sheets at December 31:						
Noncurrent Assets	\$ 11,678	\$ 5,742	\$ —	\$ —	\$ —	\$ —
Current Liabilities	—	—	(2,679)	(2,414)	(2,469)	(2,970)
Noncurrent Liabilities and Deferred Credits	—	—	(33,101)	(33,210)	(27,676)	(46,977)
Net Asset (Liability)	\$ 11,678	\$ 5,742	\$ (35,780)	\$ (35,624)	\$ (30,145)	\$ (49,947)

The accumulated benefit obligation of our Pension Plan was \$288.8 million and \$283.2 million as of December 31, 2023 and 2022. The accumulated benefit obligation of our ESSRP was \$35.8 million and \$35.6 million as of December 31, 2023 and 2022.

In 2023, the Company amended its postretirement healthcare plan to eliminate, for Medicare-eligible participants, the employer-sponsored group waiver medical plan and instead allow participants to select an individual medical plan through a private marketplace exchange. The Company now provides these plan participants with an annual reimbursement to subsidize their medical premiums. The effect of the plan amendment reduced the Company's projected benefit obligation by \$20.1 million. The reduced benefit obligation included a \$2.6 million reduction attributable to an increase in the discount rate used to measure the plan liability, which was 6.06% at the time of the amendment, compared to 5.52% used at December 31, 2022. The \$17.5 million of savings attributable to the plan change is being recognized as a reduction to expense over 4.8 years, the expected remaining service period to retirement-age eligibility for active participants.

The following assumptions were used to determine benefit obligations as of December 31, 2023 and 2022:

	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2023</i>	<i>2022</i>	<i>2023</i>	<i>2022</i>	<i>2023</i>	<i>2022</i>
Discount Rate	5.57 %	5.51 %	5.53 %	5.51 %	5.53 %	5.52 %
Long-Term Rate of Compensation Increase	n/a	n/a	3.00 %	3.00 %	n/a	n/a
Participants up to Age 39 ⁽¹⁾	4.50 %	4.50 %	n/a	n/a	n/a	n/a
Participants Ages 40 to 49 ⁽²⁾	4.50 %	3.50 %	n/a	n/a	n/a	n/a
Participants Age 50 and Older ⁽³⁾	3.75 %	2.75 %	n/a	n/a	n/a	n/a
Healthcare Cost Immediate Trend Rate	n/a	n/a	n/a	n/a	6.97 %	7.50 %
Healthcare Cost Ultimate Trend Rate	n/a	n/a	n/a	n/a	4.00 %	4.00 %
Year the Rate Reaches the Ultimate Trend Rate	n/a	n/a	n/a	n/a	2048	2048

⁽¹⁾ Amount reflects rate of compensation increases for both union and non-union employees.

⁽²⁾ Amount reflects rate of compensation increases for union employees. The rate of compensation increases for non-union employees is 3.50%.

⁽³⁾ Amount reflects rate of compensation increases for union employees. The rate of compensation increases for non-union employees is 3.00%.

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 2023 and 2022 reduced our obligation by \$2.2 million and \$117.1 million. Changes in retirement rate, percentage married, spouse age, benefit election, benefit commencement age and wage assumptions increased our benefit obligation in 2023 by \$7.9 million. Changes in plan participant census data increased our benefit obligation by \$3.1 million in 2023. Actual returns on Pension Plan assets in 2023 were \$34.2 million, compared to an expected return of \$25.9 million, impacting our obligation by \$8.3 million.
- For the ESSRP, an increase in the discount rate in 2023 and 2022 reduced our obligation by \$0.1 million and \$10.2 million.
- For the postretirement healthcare plan, a plan amendment during 2023, as described above, decreased our benefit obligation by \$17.5 million. An increase in the discount rate in 2023 and 2022 reduced our obligation by \$1.3 million and \$17.9 million. Revised estimates of healthcare cost trends and participant contribution assumptions increased the benefit obligation by \$1.1 million in 2023.

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, 2023, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>			<i>Pension Benefits (ESSRP)</i>			<i>Postretirement Benefits</i>		
	<i>2023</i>	<i>2022</i>	<i>2021</i>	<i>2023</i>	<i>2022</i>	<i>2021</i>	<i>2023</i>	<i>2022</i>	<i>2021</i>
Service Cost	\$ 3,698	\$ 6,576	\$ 7,462	\$ 72	\$ 195	\$ 187	\$ 565	\$ 1,338	\$ 1,722
Interest Cost	16,436	12,344	11,660	1,889	1,341	1,228	2,416	2,041	1,891
Expected Return on Assets	(25,914)	(23,684)	(22,359)	—	—	—	—	—	—
Amortization of Prior Service Cost	—	—	—	—	—	—	(6,649)	(5,733)	(5,733)
Amortization of Net Actuarial Loss	—	7,865	10,914	—	567	620	—	3,063	3,774
Net Periodic Benefit Cost	\$ (5,780)	\$ 3,101	\$ 7,677	\$ 1,961	\$ 2,103	\$ 2,035	\$ (3,668)	\$ 709	\$ 1,654

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, 2023, 2022 and 2021:

<i>(in thousands)</i>	<i>2023</i>	<i>2022</i>	<i>2021</i>
Net Periodic Benefit Cost	\$ (7,487)	\$ 5,913	\$ 11,366
Net Amount Amortized Due to the Effect of Regulation	1,225	1,121	21
Net Periodic Benefit Cost Recognized	\$ (6,262)	\$ 7,034	\$ 11,387

The following assumptions were used to determine net periodic benefit cost for the years ended December 31, 2023, 2022 and 2021:

	<i>Pension Benefits (Pension Plan)</i>			<i>Pension Benefits (ESSRP)</i>			<i>Postretirement Benefits</i>		
	2023	2022	2021	2023	2022	2021	2023	2022	2021
Discount Rate	5.51 %	3.03 %	2.78 %	5.51 %	2.93 %	2.61 %	5.52 %	3.01 %	2.75 %
Long-Term Rate of Return on Plan Assets	7.00 %	6.30 %	6.51 %	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 %	3.00 %	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, 2023 and 2022:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	2023	2022	2023	2022	2023	2022
Regulatory Assets (Liabilities):						
Unrecognized Prior Service Cost	\$ —	\$ —	\$ —	\$ —	\$ (18,845)	\$ (8,400)
Unrecognized Actuarial Loss	85,227	85,367	1,061	979	1,759	3,993
Net Regulatory Assets (Liabilities)	85,227	85,367	1,061	979	(17,086)	(4,407)
Accumulated Other Comprehensive Income (Loss):						
Unrecognized Prior Service Cost	—	—	—	—	498	99
Unrecognized Actuarial Gain (Loss)	1,994	1,978	(1,403)	(1,093)	707	818
Total Accumulated Other Comprehensive Income (Loss)	\$ 1,994	\$ 1,978	\$ (1,403)	\$ (1,093)	\$ 1,205	\$ 917

Cash Flows. We did not make any contributions to our Pension Plan in 2023. We made discretionary contributions of \$20.0 million and \$10.0 million in 2022 and 2021. As of December 31, 2023, 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:

<i>(in thousands)</i>	2024	2025	2026	2027	2028	2029-2033
Projected Pension Plan Benefit Payments	\$ 18,851	\$ 19,274	\$ 19,828	\$ 20,318	\$ 20,882	\$ 110,291
Projected ESSRP Benefit Payments	2,747	2,697	2,823	2,994	2,938	14,437
Projected Postretirement Benefit Payments	2,469	2,497	2,544	2,547	2,476	12,045
Total	\$ 24,067	\$ 24,468	\$ 25,195	\$ 25,859	\$ 26,296	\$ 136,773

401K Plan

We sponsor a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans totaled \$7.8 million for 2023, \$6.7 million for 2022 and \$6.5 million for 2021.

11. Asset Retirement Obligations

We have recognized Asset Retirement Obligations (AROs) related to our coal-fired generation plants, natural gas combustion turbines, solar facility, 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. As of December 31, 2023 and 2022, \$0.1 million and \$2.7 million, respectively, was included in other current liabilities and \$36.4 million and \$22.5 million, respectively, was included in other noncurrent liabilities in the consolidated balance sheets related to AROs.

A reconciliation of the carrying amounts of AROs for the years ended December 31, 2023 and 2022 is as follows:

<i>(in thousands)</i>	2023		2022	
Beginning Balance	\$	25,182	\$	24,191
New Obligations Recognized		4,506		—
Adjustments Due to Revisions in Cash Flow Estimates		8,394		—
Accrued Accretion		1,191		991
Settlements		(2,796)		—
Ending Balance	\$	36,477	\$	25,182

12. Income Taxes

Income before income taxes for the years ended December 31, 2023, 2022 and 2021 consists entirely of domestic earnings.

The provision for income taxes charged to income for the years ended December 31, 2023, 2022 and 2021 consisted of the following:

<i>(in thousands)</i>	2023		2022		2021	
Current						
Federal Income Taxes	\$	41,253	\$	31,949	\$	6,806
State Income Taxes		15,126		9,568		939
Deferred						
Federal Income Taxes		9,832		22,480		18,180
State Income Taxes		3,676		9,943		10,716
Tax Credits						
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		(586)		(586)		(586)
Investment Tax Credit Amortization		(3)		(3)		(3)
Total	\$	69,298	\$	73,351	\$	36,052

The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2023, 2022 and 2021 is as follows:

	2023		2022		2021	
Income Taxes at Federal Statutory Rate	\$	76,332	21.0 %	\$ 75,082	21.0 %	\$ 44,692 21.0 %
Increases (Decreases) in Tax from:						
State Taxes on Income, Net of Federal Tax		14,429	4.0	15,049	4.2	9,962 4.7
Production Tax Credits (PTCs)		(17,394)	(4.8)	(14,985)	(4.2)	(12,503) (5.9)
Amortization of Excess Deferred Income Taxes		(2,205)	(0.6)	(1,625)	(0.5)	(4,262) (2.0)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		(586)	(0.2)	(586)	(0.2)	(586) (0.3)
Other, Net		(1,278)	(0.3)	416	0.2	(1,251) (0.6)
Income Taxes at Effective Tax Rate	\$	69,298	19.1 %	\$ 73,351	20.5 %	\$ 36,052 16.9 %

PTCs, North Dakota wind tax credits, and excess deferred income taxes related to the federal tax rate reduction in the 2017 Tax Cuts and Jobs Act are returned to customers as a reduction of the rates they are charged and result in a reduction of operating revenues.

Deferred tax assets and liabilities were composed of the following on December 31, 2023 and 2022:

<i>(in thousands)</i>	2023	2022
Deferred Tax Assets		
Employee Benefits	\$ 39,959	\$ 39,216
Regulatory Liabilities	56,479	57,353
Tax Credit Carryforwards	21,836	20,209
Cost of Removal	32,993	37,360
Asset Retirement Obligations	9,494	6,557
Net Operating Loss Carryforward	2,336	1,853
Other	11,310	5,550
Total Deferred Tax Assets	174,407	168,098
Deferred Tax Liabilities		
Differences Related to Property	(347,885)	(334,201)
Retirement Benefits Regulatory Asset	(22,458)	(22,789)
Pension Expense	(24,875)	(24,269)
Other	(16,462)	(8,141)
Total Deferred Tax Liabilities	(411,680)	(389,400)
Deferred Income Taxes	\$ (237,273)	\$ (221,302)

The following is a schedule of tax credits and tax net operating losses available as of December 31, 2023 and the respective periods of expiration:

<i>(in thousands)</i>	Amount	2024-2029	2030-2037	2038-2043
State Net Operating Losses	\$ 2,336	\$ 211	\$ 2,125	\$ —
State Tax Credits	21,836	—	—	21,836

The following table summarizes the activity for unrecognized tax benefits for the years ended December 31, 2023, 2022 and 2021:

<i>(in thousands)</i>	2023	2022	2021
Balance on January 1	\$ 923	\$ 827	\$ 771
Increases for tax positions taken during a prior period	596	44	11
Increases for tax positions taken during the current period	163	260	189
Decreases due to settlements with taxing authorities	—	—	—
Decreases as a result of a lapse of applicable statutes of limitations	(193)	(208)	(144)
Balance on December 31	\$ 1,489	\$ 923	\$ 827

The balance of unrecognized tax benefits as of December 31, 2023 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2023 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, 2023, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2020 for federal and North Dakota income taxes and prior to 2019 for Minnesota state income taxes.

13. Commitments and Contingencies

Commitments

Construction and Other Commitments. As of December 31, 2023, we had commitments under contracts for construction project materials, equipment, plant maintenance, and other services extending into 2046 which totaled approximately \$17.1 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 2048. 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 \$5.6 million, \$13.1 million and \$11.5 million for the years ended December 31, 2023, 2022 and 2021.

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, and no amounts for this agreement have been included in the table below; however, under this agreement all of Big Stone Plant’s coal requirements for the period covered must be purchased under this agreement. Coal purchase costs under these two agreements totaled \$43.7 million, \$45.1 million and \$40.4 million for the years ended December 31, 2023, 2022 and 2021.

Land Easement Payments. OTP has commitments to make payments for land easements not classified as leases. The contractual terms of these easements are generally 99 years or do not have a stated maturity date, however, per the terms of the agreements, our requirement to make payment ends once we cease use of the land. As such, in the table below, we have included payments under these easements through the estimated useful lives of the facilities associated with the easement. The commitments under these arrangements extend into 2055 and total approximately \$62.4 million. Land easement costs under these agreements totaled \$1.8 million, \$1.4 million and \$1.3 million for the years ended December 31, 2023, 2022 and 2021.

Our future commitments as of December 31, 2023 were as follows:

<i>(in thousands)</i>	<i>Construction Program and Other Commitments</i>	<i>Capacity and Energy Requirements</i>	<i>Coal Purchase Commitments</i>	<i>Land Easement Payments</i>
2024	\$ 4,374	\$ 245	\$ 24,691	\$ 1,804
2025	4,051	217	24,593	1,840
2026	1,377	197	25,374	1,845
2027	594	197	25,786	1,882
2028	550	197	25,344	1,921
Beyond 2028	6,165	3,939	359,610	53,107
Total	\$ 17,111	\$ 4,992	\$ 485,398	\$ 62,399

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 \$2.8 million as of December 31, 2023. 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 EPA 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 (SIP) 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 SIP. The NDDEQ submitted its 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 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 SIP may have on our business until the SIP 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 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, 2023 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, 2023 or 2022.

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 2023.

On May 3, 2021, upon the expiration of a prior shelf registration, we filed a 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 2023, we issued 105,663 common shares under this program and no proceeds were received, as all shares issued were purchased on the open market. As of December 31, 2023, 1,145,330 shares remained 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 intercompany distributions made by OTC's subsidiaries to OTC. 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, 2023, 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 48.3% and 59.1%, with total capitalization not to exceed \$2.0 billion based on OTP's capital structure requirements as of December 31, 2023. As of December 31, 2023, OTP's equity-to-total-capitalization ratio including short-term debt was 54.2% and its net assets restricted from distribution totaled approximately \$771.3 million.

15. Accumulated Other Comprehensive Income (Loss)

The Company's other comprehensive income (loss) 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, 2023, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension and Other Postretirement Benefits</i>	<i>Net Unrealized Gain (Losses) on Available-for- Sale Securities</i>	<i>Total</i>
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
Other Comprehensive Income Before Reclassifications, net of tax	59	180	239
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(18) ⁽¹⁾	12 ⁽²⁾	(6)
Total Other Comprehensive Income	41	192	233
Balance, December 31, 2023	\$ 1,375	\$ (227)	\$ 1,148

⁽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. 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, \$0.3 million and \$0.2 million for the years ended December 31, 2023, 2022 and 2021. For the years ended December 31, 2023, 2022 and 2021 the amount of shares issued under the plan amounted to 26,348, 26,420 and 27,975 shares. As of December 31, 2023, there were 237,367 shares available for purchase under the plan.

Share-Based Compensation Plan

The 2023 Stock Incentive Plan, which was approved by our shareholders in April 2023, authorizes the issuance of 979,891 common shares, including 500,000 newly requested common shares, for the granting of stock options, stock appreciation rights, restricted stock, restricted stock units, dividend equivalents, performance awards and other stock-based awards. In addition, common shares subject to any outstanding awards under our prior stock incentive plans that are forfeited, canceled or reacquired by the Company will become available for re-issuance under the 2023 Stock Incentive Plan. As of December 31, 2023, 943,192 shares were available for issuance under the plan. The plan terminates on April 17, 2033.

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 \$7.4 million, \$6.6 million and \$6.7 million for the years ended December 31, 2023, 2022 and 2021. The related income tax benefit recognized for these periods amounted to \$1.6 million, \$1.7 million and \$1.8 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, 2023:

	<i>Shares</i>	<i>Weighted-Average Grant-Date Fair Value</i>
Nonvested, Beginning of Year	141,551	\$ 49.83
Granted	55,205	68.03
Vested	(45,493)	50.02
Forfeited	(2,350)	52.02
Nonvested, End of Year	148,913	\$ 56.48

The weighted-average grant-date fair value of granted awards was \$68.03, \$59.95 and \$43.55 during the years ended December 31, 2023, 2022 and 2021. The fair value of vested awards was \$3.1 million, \$3.0 million and \$2.1 million during the years ended December 31, 2023, 2022 and 2021. As of December 31, 2023, there was \$3.4 million of unrecognized compensation cost for unvested restricted stock awards to be recognized over a weighted-average period of 1.7 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 on actual performance at the end of the performance period.

The grant-date fair value of the ROE component of the stock performance awards granted during the years ended December 31, 2023, 2022 and 2021 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, 2023, 2022 and 2021 was determined using a Monte Carlo fair value simulation model incorporating the following assumptions:

	<i>2023</i>	<i>2022</i>	<i>2021</i>
Risk-free interest rate	4.15 %	1.52 %	0.18 %
Expected term (in years)	3.00	3.00	3.00
Expected volatility	34.00 %	32.00 %	32.00 %
Dividend yield	2.50 %	2.90 %	3.60 %

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 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, 2023 (share amounts reflect awards at target):

	<i>Shares</i>	<i>Weighted-Average Grant-Date Fair Value</i>
Nonvested, Beginning of Year	189,800	\$ 45.95
Granted	59,400	61.97
Vested	(55,000)	47.79
Forfeited	—	—
Nonvested, End of Year	194,200	\$ 50.33

The weighted-average grant-date fair value of granted awards was \$61.97, \$54.91 and \$38.34 during the years ended December 31, 2023, 2022 and 2021. The fair value of vested awards was \$5.3 million, \$5.1 million and \$2.5 million during the years ended December 31, 2023, 2022 and 2021.

2021. As of December 31, 2023, there was \$0.4 million of unrecognized compensation cost of unvested stock performance awards to be recognized over a weighted-average period of 0.67 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 shares associated with time and performance based stock awards and our employee stock purchase plan.

The following includes the computation of the denominator for basic and diluted weighted-average shares outstanding for the years ended December 31, 2023, 2022 and 2021:

<i>(in thousands)</i>	2023	2022	2021
Weighted Average Common Shares Outstanding – Basic	41,668	41,586	41,491
Effect of Dilutive Securities:			
Stock Performance Awards	269	248	226
Restricted Stock Awards	100	95	87
Employee Stock Purchase Plan Shares and Other	2	2	14
Dilutive Effect of Potential Common Shares	371	345	327
Weighted Average Common Shares Outstanding – Diluted	42,039	41,931	41,818

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, 2023, 2022 and 2021.

18. Derivative Instruments

OTP enters into derivative instruments to manage its exposure to future commodity price variability, specifically future wholesale energy and natural gas prices, 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, 2023 and 2022 OTP had outstanding pay-fixed, receive-variable swap agreements with an aggregate notional amount of 187,400 and 295,000 megawatt-hours of electricity. The contracts outstanding as of December 31, 2023 had various settlement dates throughout 2024. As of December 31, 2023 and 2022, the fair value of these derivative instruments was \$4.2 million and \$7.1 million, which are included in other current liabilities on the consolidated balance sheets. During the years ended December 31, 2023 and 2022, contracts matured and were settled in an aggregate amount of a \$16.5 million loss and a \$1.0 million gain, respectively. Gains and losses recognized on the settlement of derivative instruments are returned to, or recovered from, our electric customers through fuel recovery mechanisms in each state. When recognized in the statement of income, these gains or losses are included in electric purchased power.

19. Fair Value Measurements

The following tables present our assets measured at fair value on a recurring basis as of December 31, 2023 and 2022 classified by the input method used to measure fair value:

	<i>Level 1</i>	<i>Level 2</i>	<i>Level 3</i>
December 31, 2023			
Assets			
Investments:			
Money Market Funds	\$ 3,125	\$ —	\$ —
Mutual Funds	7,771	—	—
Corporate Debt Securities	—	1,579	—
Government Debt Securities	—	7,724	—
Total Assets	10,896	9,303	—
Liabilities			
Derivative Instruments	—	4,210	—
Total Liabilities	\$ —	\$ 4,210	\$ —
December 31, 2022			
Assets			
Investments:			
Money Market Funds	\$ 1,560	\$ —	\$ —
Mutual Funds	5,503	—	—
Corporate Debt Securities	—	1,434	—
Government Debt Securities	—	7,327	—
Total Assets	\$ 7,063	\$ 8,761	\$ —
Liabilities			
Derivative Instruments	—	7,130	—
Total Liabilities	\$ —	\$ 7,130	\$ —

The level 2 fair value measurements for government 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, 2023 and 2022:

<i>(in thousands)</i>	<i>December 31, 2023</i>		<i>December 31, 2022</i>	
	<i>Carrying Amount</i>	<i>Fair Value</i>	<i>Carrying Amount</i>	<i>Fair Value</i>
Assets:				
Cash and Cash Equivalents	\$ 230,373	\$ 230,373	\$ 118,996	\$ 118,996
Total	230,373	230,373	118,996	118,996
Liabilities:				
Short-Term Debt	81,422	81,422	8,204	8,204
Long-Term Debt	824,059	710,839	823,821	681,615
Total	\$ 905,481	\$ 792,261	\$ 832,025	\$ 689,819

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, 2023, 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, 2023.

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, 2023 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, 2023. 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, 2023, 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 2024 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 2024 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 2024 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 2024 Annual Meeting.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

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 2024 Annual Meeting.

The following table sets forth information as of December 31, 2023 about the Company’s common stock that may be issued under all its equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders:			
2023 Stock Incentive Plan	409,880 ⁽¹⁾	N/A	943,192 ⁽²⁾
1999 Employee Stock Purchase Plan	—	N/A	237,367 ⁽³⁾
Equity compensation plans not approved by security holders			
Total	409,880	—	1,180,559

(1) Includes 89,100, 83,700 and 118,500 performance-based share awards, assuming a maximum payout, granted in 2023, 2022 and 2021, respectively, and 118,580 restricted stock units outstanding as of December 31, 2023.

(2) The 2023 Stock Incentive Plan provides for the issuance of any shares available under the plan in the form of restricted stock, restricted stock units, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights.

(3) Shares to be issued based on employee’s election to participate in the plan.

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 2024 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 2024 Annual Meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. Financial Statements

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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**

<i>(in thousands)</i>	<i>December 31,</i>	
	2023	2022
Assets		
Current Assets		
Cash and Cash Equivalents	\$ 228,137	\$ 119,246
Accounts Receivable from Subsidiaries	2,555	3,278
Interest Receivable from Subsidiaries	117	117
Other	977	1,045
Total Current Assets	231,786	123,686
Investments in Subsidiaries	1,725,584	1,463,998
Notes Receivable from Subsidiaries	78,900	78,900
Deferred Income Taxes	65,244	64,802
Other Assets	50,795	43,779
Total Assets	\$ 2,152,309	\$ 1,775,165
Liabilities and Stockholders' Equity		
Current Liabilities		
Accounts Payable to Subsidiaries	\$ 7	\$ 7
Notes Payable to Subsidiaries	568,672	420,363
Other	15,320	15,994
Total Current Liabilities	583,999	436,364
Other Noncurrent Liabilities	45,455	41,686
Commitments and Contingencies		
Capitalization		
Long-Term Debt	79,849	79,798
Common Stockholders' Equity	1,443,006	1,217,317
Total Capitalization	1,522,855	1,297,115
Total Liabilities and Stockholders' Equity	\$ 2,152,309	\$ 1,775,165

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
CONDENSED STATEMENTS OF INCOME

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	2023	2022	2021
Income			
Equity Income in Earnings of Subsidiaries	\$ 294,467	\$ 296,833	\$ 188,375
Interest Income from Subsidiaries	2,898	3,382	2,826
Other Income	10,496	466	1,290
Total Income	307,861	300,681	192,491
Expense			
Nonelectric Selling, General, and Administrative Expenses	12,816	17,269	14,825
Interest Expense	3,813	4,066	4,727
Interest Expense from Subsidiaries	6	5	3
Nonservice Cost Components of Postretirement Benefits	1,063	1,023	1,097
Total Expense	17,698	22,363	20,652
Income Before Income Taxes	290,163	278,318	171,839
Income Tax Benefit	4,028	5,866	4,930
Net Income	\$ 294,191	\$ 284,184	\$ 176,769

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
CONDENSED STATEMENTS OF CASH FLOWS

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	2023	2022	2021
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	\$ 77,139	\$ 28,807	\$ 60,695
Cash Flows from Investing Activities			
Investment in Subsidiaries	(40,000)	(50,000)	—
Debt Repaid by Subsidiaries	—	—	169
Other, net	(68)	(1,695)	(884)
Net Cash Used in Investing Activities	(40,068)	(51,695)	(715)
Cash Flows from Financing Activities			
Net (Repayments) Borrowings on Short-Term Debt	—	(22,637)	(42,529)
Borrowings from Subsidiaries	148,308	236,926	49,085
Proceeds from Issuance of Common Stock	—	—	696
Payments for Shares Withheld for Employee Tax Obligations	(3,088)	(2,942)	(1,507)
Payments for Retirement of Long-Term Debt	—	—	(169)
Dividends Paid	(73,061)	(68,755)	(64,864)
Other, net	(339)	(461)	(689)
Net Cash Provided by (Used in) Financing Activities	71,820	142,131	(59,977)
Net Change in Cash and Cash Equivalents	108,891	119,243	3
Cash and Cash Equivalents at Beginning of Period	119,246	3	—
Cash and Cash Equivalents at End of Period	\$ 228,137	\$ 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 generally accepted accounting principles. 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, 2023 and 2022 are as follows:

<i>(in thousands)</i>	<i>Accounts Receivable</i>	<i>Interest Receivable</i>	<i>Long-Term Notes Receivable</i>	<i>Accounts Payable</i>	<i>Current Notes Payable</i>
December 31, 2023					
Otter Tail Power Company	\$ 2,415	\$ —	\$ —	\$ 7	\$ —
Northern Pipe Products, Inc.	—	7	5,000	—	56,917
Vinyltech Corporation	14	17	11,500	—	98,016
BTD Manufacturing, Inc.	—	78	52,000	—	6,291
T.O. Plastics, Inc.	36	15	10,400	—	980
Varistar Corporation	—	—	—	—	406,468
Otter Tail Assurance Limited	90	—	—	—	—
	\$ 2,555	\$ 117	\$ 78,900	\$ 7	\$ 568,672
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

Dividends

Dividends paid to OTC (the Parent) from its subsidiaries were as follows:

<i>(in thousands)</i>	2023	2022	2021
Cash Dividends Paid to Parent by Subsidiaries	\$ 72,982	\$ 68,680	\$ 64,790

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, 2023, 2022 and 2021:

<i>(in thousands)</i>	<i>Balance, January 1</i>	<i>Charged to Cost and Expenses</i>	<i>Deductions^{1, 2}</i>	<i>Balance, December 31</i>
Allowance for Credit Losses				
2023	\$ 1,648	\$ 2,014	\$ (1,140)	\$ 2,522
2022	1,836	909	(1,097)	1,648
2021	3,215	93	(1,472)	1,836
Deferred Tax Asset Valuation Allowance				
2023	\$ —	\$ —	\$ —	\$ —
2022	—	—	—	—
2021	800	—	(800)	—

¹Amounts under Allowance for Credit Losses reflect deductions to the allowance for amounts written-off, net of recoveries.

²Amounts 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.
10.13.0	Deferred Compensation Plan for Directors (2003 Restatement).*

No.	Description
10.13.1	First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as Amended.*
10.13.2	Second Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as Amended.*
10.14	Executive Survivor and Supplemental Retirement Plan (2020 Restatement).*
10.15	Nonqualified Retirement Plan (2021 Restatement).*
10.16	1999 Employee Stock Purchase Plan, As Amended (2016).
10.17	2014 Stock Incentive Plan
10.18	2023 Executive Annual Incentive Plan.*
10.19	Otter Tail Corporation Executive Restoration Plus Plan, 2020 Restatement.*
10.20	Summary of Non-Employee Director Compensation (2023).*
10.21	Change in Control Severance Agreement, Chuck MacFarlane, dated February 24, 2012.*
10.22	Change in Control Severance Agreement, Timothy Rogelstad, dated April 14, 2014.*
10.23	Change in Control Severance Agreement, Paul Knutson, dated December 17, 2012.*
10.24	Change in Control Severance Agreement, John Abbott, dated April 13, 2015.*
10.25	Change in Control Severance Agreement, Todd Wahlund, dated January 1, 2024.*
10.26	Change in Control Severance Agreement, Jennifer Smestad, dated January 1, 2018.*
10.27	Form of Change in Control Severance Agreement (2023)*
10.28	Otter Tail Corporation Executive Severance Plan (2024).*
10.29	Form of 2023 Restricted Stock Award Agreements for Directors
10.30	2023 Stock Incentive Plan
10.31	Form of 2023 Executive Performance Share Award Agreement (Executives)
10.32	Form of 2023 Restricted Stock Unit Award Agreement (Executives)
10.33	Consulting Agreement, Kevin G. Moug, dated January 8, 2024*
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.
97	Incentive Compensation Recovery Policy
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/ Todd R. Wahlund
Todd R. Wahlund
Vice President and Chief Financial Officer
(authorized officer and principal financial officer)

Dated: February 14, 2024

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)	
)	
Todd R. Wahlund)	
Vice President and Chief Financial Officer)	
(principal financial and accounting officer))	
)	By <u>/s/ Charles S. MacFarlane</u>
Nathan I. Partain)	Charles S. MacFarlane
Chairman of the Board and Director)	Pro Se and Attorney-in-Fact
)	Dated: February 14, 2024
Karen M. Bohn, Director)	
)	
Jeanne H. Crain, Director)	
)	
John D. Erickson, Director)	
)	
Steven L. Fritze, Director)	
)	
Kathryn O. Johnson, Director)	
)	
Michael E. LeBeau, Director)	
)	
Mary E. Ludford, Director)	
)	
Thomas J. Webb, Director)	

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. 2023 dividends were \$1.75 per share, and the year-end dividend yield was 2.1 percent. Total shareholder return grew at a compounded average annual rate of 14.9 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 83 percent of eligible shareholders holding approximately 7 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.

2024 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 8, 2024 • 10:00 a.m., Central Daylight Time / Meeting Format: Virtual-only

2024 COMMON DIVIDEND DATES

Ex-Dividend	Record	Payment
February 14	February 15	March 8
May 14	May 15	June 10
August 15	August 15	September 10
November 15	November 15	December 10

KEY STATISTICS

Nasdaq	OTTR
Year-end stock price	\$84.97
Year-end market-to-book ratio	2.46
Annual dividend yield	2.1%
Shares outstanding (as of December 31, 2023)	41.7 million
Market capitalization (as of December 31, 2023)	\$3.5 billion
2023 average daily trading volume	259,222
Institutional holdings (shares as of December 31, 2023)	28.7 million

TRANSFER AGENT

Equiniti Shareowner Services
P.O. Box 64856, St. Paul, MN 55164-0856
Phone: 800-468-9716 or 651-450-4064

2023 CREDIT RATINGS

	Moody's	Fitch	S&P
Otter Tail Corporation:			
Issuer Default Rating	Baa2	BBB	BBB
Senior Unsecured Debt	n/a	BBB	n/a
Outlook	Stable	Stable	Stable

Otter Tail Power Company:

Issuer Default Rating	A3	BBB+	BBB+
Senior Unsecured Debt	n/a	A-	n/a
Outlook	Stable	Stable	Stable

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



SHAREHOLDER SERVICES

215 S. Cascade St., P.O. Box 496

Fergus Falls, MN 56538-0496

Phone: 800-664-1259 or 218-739-8479

Email: sharesvc@ottertail.com

www.ottertail.com / Nasdaq: OTTR

THIS FILING IS

Item 1:

An Initial (Original) Submission

OR

Resubmission No.



**FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of
Major Electric Utilities, Licensees
and Others and Supplemental
Form 3-Q: Quarterly Financial Report**

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)

Otter Tail Power Company

Year/Period of Report
End of: 2023/ Q4

FERC FORM NO. 1 (REV. 02-04)

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject to the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

- Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at <https://eCollection.ferc.gov>, and according to the specifications in the Form 1 and 3-Q taxonomies.
- The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.
- Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426
- For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

- The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faq-efilingferc-online>.
- Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <https://www.ferc.gov/general-information-0/electric-industry-forms>.

- FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

- Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USoFA). Interpret all accounting words and phrases in accordance with the USoFA.
- Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).
- Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.
- Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.
- Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

DEFINITIONS

- Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was

obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

FERC FORM NO. 1 (ED, 03-07)

a. "To make investigations and to collect and record data concerning the utilization of the water resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special" reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies".¹⁰

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to \$1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

**FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

IDENTIFICATION

01 Exact Legal Name of Respondent Otter Tail Power Company		02 Year/ Period of Report End of: 2023/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 215 South Cascade Street, PO Box 496, Fergus Falls, MN 56538-0496		
05 Name of Contact Person Janelle Johnson		06 Title of Contact Person Controller, Utility
07 Address of Contact Person (Street, City, State, Zip Code) 215 South Cascade Street, PO Box 496 Fergus Falls, MN 56538-0496		
08 Telephone of Contact Person, Including Area Code 218-739-8758	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2023
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Andrew Miller	03 Signature Andrew Miller	04 Date Signed (Mo, Da, Yr) 04/16/2024
02 Title Chief Financial Officer		
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	Not Applicable
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	106(b) Not Applicable
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	Not Applicable
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	Not Applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	Not Applicable
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	Not Applicable
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	Not Applicable
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not Applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	Not Applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	Not Applicable
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	Not Applicable
65	Pumped Storage Generating Plant Statistics	408	Not Applicable
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	Not Applicable
66.2	Energy Storage Operations (Small Plants)	419	Not Applicable
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
Stockholders' Reports (check appropriate box)			
Stockholders' Reports Check appropriate box:			
<input type="checkbox"/> Two copies will be submitted			
<input checked="" type="checkbox"/> No annual report to stockholders is prepared			

Page 2

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Janelle Johnson

Controller, Utility

215 South Cascade Street, PO Box 496 Fergus Falls, MN 56538-0496

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: MN

Date of Incorporation: 1907-07-05

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Minnesota - Electric North Dakota - Electric South Dakota - Electric

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?
(1)

Yes

(2)

No

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
CONTROL OVER RESPONDENT			
1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.			
Otter Tail Corporation, a registered holding company, owns all of the common stock of the respondent.			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Not applicable.			

Name of Respondent: Otter Tail Power Company	This report is: (1) ♦ An Original (2) D A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Chief Executive Officer, Utility*	Charles S. MacFarlane			
2	President, Utility	Timothy J. Rogelstad			
3	Vice President, Customer Service	Steve J. Schoeneck			
4	Chief Financial Officer	Todd R. Wahlund			2023-12-31
5	Vice President, Regulatory Affairs	Bruce G. Gerhardson			
6	General Counsel & Vice President, Legal Affairs *	Jennifer O. Smestad			
7	Vice President, Asset Management	JoAnn M. Thompson			
8	Vice President, Energy Supply	Bradley E. Tollerson			
9	Director, Human Resources & Safety	Peter E. Wasberg			
10	Vice President, Information Technology*	Don L. Redden			
11	Director, Public Relations	Stephanie A. Hoff			
12	Treasurer*	Kevin G. Moug			2023-12-31
13	Assistant Treasurer*	Andrew C. Miller			2023-12-31
14	* This individual is an employee of Otter Tail Corporation				
15	and a portion of their salary is allocated to the				
16	respondent. The reported amount is prorated to the				
17	utility.				

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Charles MacFarlane, Director, Chief Executive Officer	Fergus Falls, Minnesota	false	false
2	Kevin Moug, Director	Fargo, North Dakota	false	false
3	Timothy Rogelstad, Director; President	Fergus Falls, Minnesota	false	false
4	John Abbott, Director	Fargo, North Dakota	false	false
5	Jennifer Smestad, Director	Fergus Falls, Minnesota	false	false

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	MISO FERC Electric Tariff Original Vol. No. 1	ER98-1438-000
2	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER04-895-000
3	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER05-122-000
4	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER04-458-008
5	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-18-000
6	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-159-000
7	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER09-91-000
8	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1657-000
9	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1779-000
10	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-183
11	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-686
12	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1492-000
13	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1791
14	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER10-1997-000;001
15	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-28-000;001
16	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3279-000
17	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3704-000
18	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-297-000
19	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-312-000
20	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-334-000
21	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-450-000
22	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-715-000;002
23	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-1667-000
24	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-263-001
25	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-674-000;002
26	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-1169-000
27	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-1169-001
28	MISO FERC Electric Tariff	ER12-480-006;007
29	MISO FERC Electric Tariff	ER13-2379-000;003;004
30	MISO FERC Electric Tariff	ER14-260-000
31	MISO FERC Electric Tariff	ER14-261-000
32	MISO FERC Electric Tariff	ER14-421-000;001
33	MISO FERC Electric Tariff	ER15-358
34	MISO FERC Electric Tariff	ER15-1490
35	MISO FERC Electric Tariff	ER16-1313
36	MISO FERC Electric Tariff	ER16-1534
37	MISO FERC Electric Tariff	ER16-392
38	MISO FERC Electric Tariff	ER16-197
39	MISO FERC Electric Tariff	ER17-1014
40	MISO FERC Electric Tariff	ER17-1393
41	MISO FERC Electric Tariff	ER18-867
42	MISO FERC Electric Tariff	ER18-1982
43	MISO FERC Electric Tariff	ER18-1159-000
44	MISO FERC Electric Tariff	ER19-249-000
45	MISO FERC Electric Tariff	ER19-652-000

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
46	MISO FERC Electric Tariff	ER19-2050-000; 002
47	MISO FERC Electric Tariff	ER20-175-000
48	MISO FERC Electric Tariff	ER20-176-000
49	MISO FERC Electric Tariff	ER20-1167-000
50	MISO FERC Electric Tariff	ER21-1563-000
51	MISO FERC Electric Tariff	ER21-200-000
52	MISO FERC Electric Tariff	ER21-262-000
53	MISO FERC Electric Tariff	ER22-90-000
54	MISO FERC Electric Tariff	ER22-1579
55	MISO FERC Electric Tariff	ER23-2311
Page 106		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20190315-5163	03/15/2019	ER19-1336	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff
2	20200313-5137	03/13/2020	ER20-1278	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff
3	20210315-5306	03/15/2021	ER21-1418	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff
4	20220315-5246	03/15/2022	ER22-1348	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None.

2. None.

3. Not Applicable.

4. None.

5. None.

6. See Note 9 (Short-Term and Long-Term Borrowings) in the Notes to Financial Statements and the Capital Resource Section of Otter Tail Corporation's 2023 10-K Filing with the Securities Exchange Commission (SEC).

7. None.

8. None.

9. See Item 3, Legal Proceedings in Part I of Otter Tail Corporation's 2023 10-K filing with the Securities Exchange Commission (SEC).

10. None.

13. Todd R. Wahlund, Chief Financial Officer, removed effective December 31, 2023, Kevin G. Moug, Treasurer, removed effective December 31, 2023, Andrew C. Miller, Assistant Treasurer, removed effective December 31, 2023.

14. Not Applicable.

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	3,024,574,378	2,851,416,666
3	Construction Work in Progress (107)	200	146,671,993	118,374,711
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,171,246,371	2,969,791,377
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,009,079,480	985,407,109
6	Net Utility Plant (Enter Total of line 4 less 5)		2,162,166,891	1,984,384,268
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,162,166,891	1,984,384,268
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		217,138	269,036
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		30,227	30,227
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		14,331,458	8,068,151
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		14,578,823	8,367,414
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		19,177	6,533
36	Special Deposits (132-134)		2,295,368	7,005,266
37	Working Fund (135)		12,513	11,463
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		22,294,293	25,432,510
41	Other Accounts Receivable (143)		8,384,943	9,443,705
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,495,442	1,249,454
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		6,853	6,853
45	Fuel Stock (151)	227	12,139,789	11,000,592
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	40,994,826	32,716,145
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	80,111	111,884
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		4,730,948	2,683,983
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		21,271,185	23,871,752
62	Miscellaneous Current and Accrued Assets (174)		1,272,756	
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		112,007,320	111,041,232
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		3,226,368	3,593,164
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	1,223,484	1,310,240
72	Other Regulatory Assets (182.3)	232	120,900,369	127,348,666
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		423,695	172,376
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	1,126,998	
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		215,669	240,317
82	Accumulated Deferred Income Taxes (190)	234	105,704,925	122,236,993
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		232,821,508	254,901,756
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,521,574,542	2,358,694,670

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Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

FOOTNOTE DATA

(a) Concept: ConstructionWorkInProgress

Per its FERC-approved tariff, the Company uses a 13-month average of CWIP for rate-making purposes, illustrated as follows for the current year:

	CWIP
December 31, 2022	118,374,711
January 31, 2023	124,604,714
February 28, 2023	130,053,978
March 31, 2023	133,406,564
April 30, 2023	139,084,086
May 31, 2023	140,273,144
June 30, 2023	147,998,417
July 31, 2023	167,569,422
August 31, 2023	136,582,454
September 30, 2023	137,351,398
October 31, 2023	142,584,100
November 30, 2023	146,571,177
December 31, 2023	146,671,993
13-month average for rate-making	139,317,397

(b) Concept: AccumulatedProvisionForUncollectibleAccountsCredit

As of December 31, 2023, total allowance for credit losses includes an amount of -\$52,706 for provisions for uncollectible accounts related to unbilled revenue estimates which is included in FERC account 173.

	December 31, 2023	December 31, 2022
Accum Prov. for Uncollectible Accts (FERC 144)	(1,495,442)	(1,249,454)
Estimated losses as a reduction of Unbilled Revenue included in FERC acct 173	(52,706)	(60,272)
Total Allowance for Credit Losses	<u>(1,548,148)</u>	<u>(1,309,726)</u>

(c) Concept: FuelStock

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Fuel Stock
December 31, 2022	11,000,592
January 31, 2023	11,885,742
February 28, 2023	11,611,972
March 31, 2023	11,549,658
April 30, 2023	10,910,673
May 31, 2023	9,662,459
June 30, 2023	10,426,809
July 31, 2023	10,473,211
August 31, 2023	10,495,148
September 30, 2023	10,444,374
October 31, 2023	10,593,590
November 30, 2023	12,635,452
December 31, 2023	12,139,789
13-month average for rate-making	11,063,805

(d) Concept: AllowanceInventoryAndWithheld

Renewable Energy Credits and emissions allowances are held in the allowance inventory account (158.1) for future use.

Solar REC Emission Allowance Inventory	41,789
Co-Gen REC Emission Allowance Inventory	<u>38,322</u>
	80,111

(e) Concept: Prepayments

Per its FERC-approved tariff, the Company uses a 13 month average of allowable prepaid expenses for rate-making purposes, illustrated as follows for the current year:

December 31, 2022	2,683,983
January 31, 2023	5,444,758
February 28, 2023	5,513,991
March 31, 2023	5,027,981
April 30, 2023	7,641,825
May 31, 2023	8,064,916
June 30, 2023	7,020,181
July 31, 2023	6,085,094
August 31, 2023	6,525,687
September 30, 2023	5,702,119
October 31, 2023	4,713,820
November 30, 2023	5,386,358
December 31, 2023	<u>4,730,948</u>
13-month average for rate-making	5,733,974

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250	500	500
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	676,988,966	636,988,966
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	299,566,317	273,527,850
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(1,176,918)	(1,086,005)
16	Total Proprietary Capital (lines 2 through 15)		975,378,865	909,431,311
17	LONG-TERM DEBT			
18	Bonds (221)	256	747,000,000	747,000,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)			
24	Total Long-Term Debt (lines 18 through 23)		747,000,000	747,000,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)			
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		620,797	680,181
29	Accumulated Provision for Pensions and Benefits (228.3)		46,185,000	65,191,975
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			1,843,265
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		36,476,624	25,182,260
35	Total Other Noncurrent Liabilities (lines 26 through 34)		83,282,421	92,897,681
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		81,421,764	8,203,643
38	Accounts Payable (232)		65,793,684	73,752,876
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		2,415,270	3,016,333
41	Customer Deposits (235)		498,154	575,926
42	Taxes Accrued (236)	262	18,314,311	17,375,004
43	Interest Accrued (237)		9,117,335	8,989,895
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		1,849,712	1,733,300
48	Miscellaneous Current and Accrued Liabilities (242)		477,551	411,943
49	Obligations Under Capital Leases-Current (243)			

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
50	Derivative Instrument Liabilities (244)		4,209,982	7,130,408
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		184,097,763	121,189,328
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,156,731	4,477,091
57	Accumulated Deferred Investment Tax Credits (255)	266	15,171,590	15,916,108
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	2,225,072	2,648,845
60	Other Regulatory Liabilities (254)	278	184,567,182	147,555,795
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	10,501,748	10,629,721
63	Accum. Deferred Income Taxes-Other Property (282)		292,837,405	279,386,187
64	Accum. Deferred Income Taxes-Other (283)		25,355,765	27,562,603
65	Total Deferred Credits (lines 56 through 64)		531,815,493	488,176,350
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,521,574,542	2,358,694,670

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Amort of Loss on Reacquired Debt (pre holdco)	53,208
Deferred HLP Cost Recovery	(323,742)
South Dakota Flow Thru-Overheads	(53,076)
Prepaid Expenses	1,191,222
ADR Repair Allowance	1,253,400
Sec 162 & 174 R&D Deduction	1,879,304
Highway Reimbursements	817,042
AFUDC on Debt	4,366,676
Capitalized Overheads	(1,097,678)
Repairs Deduction - Basis Adjustments	3,882,401
Sec 481(a) Cap to Repair Basis Adjustments (PY)	(4,188,887)
Excess Tax over book Depreciation	313,155,336
North Dakota Investment Tax Credit - Federal Impacts	5,296,660
Excess Accumulated Deferred Tax due to Federal Rate Change	(34,076,015)
ASC 740 (SFAS 109) ADIT Credits - Property	681,554
	<u>292,837,405</u>

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Pensions	-25,264,479
Conservation Improvement Program - MN & SD - Net (BTL)	-3,245,068
Rate Rider Mechanism	4,019,808
ND Rate Case Expenses	-118,290
MN Rate Case Expenses	-199,876
SD Rate Case Expenses	1
Regulatory Adjustments - JE 820 ESSRP	414,089
Excess Accumulated Deferred Tax due to Federal Rate Change	618,528
ASC 740 (SFAS 109) ADIT Credits - Non-Property	-1,580,478
	<u>-25,355,765</u>

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	524,114,351	545,474,498			524,114,351	545,474,498				
3	Operating Expenses											
4	Operation Expenses (401)	320	279,671,571	305,363,870			279,671,571	305,363,870				
5	Maintenance Expenses (402)	320	36,423,449	36,636,350			36,423,449	36,636,350				
6	Depreciation Expense (403)	336	69,343,913	64,650,111			69,343,913	64,650,111				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	631,942	521,899			631,942	521,899				
8	Amort. & Depl. of Utility Plant (404-405)	336	3,904,889	3,561,857			3,904,889	3,561,857				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			181,383				181,383				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		377,093	608,439			377,093	608,439				
13	(Less) Regulatory Credits (407.4)		1,903,988	(580,430)			1,903,988	(580,430)				
14	Taxes Other Than Income Taxes (408.1)	262	16,604,736	17,733,835			16,604,736	17,733,835				
15	Income Taxes - Federal (409.1)	262	(20,740,034)	(22,875,139)			(20,740,034)	(22,875,139)				
16	Income Taxes - Other (409.1)	262	(2,842,754)	(4,004,146)			(2,842,754)	(4,004,146)				

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
17	Provision for Deferred Income Taxes (410.1)	234, 272	2,499,070	13,857,976			2,499,070	13,857,976				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	(23,020,043)	(18,167,109)			(23,020,043)	(18,167,109)				
19	Investment Tax Credit Adj. - Net (411.4)	266	(744,518)	(744,523)			(744,518)	(744,523)				
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)			10				10				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		1,191,251	991,557			1,191,251	991,557				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		407,436,663	435,230,998			407,436,663	435,230,998				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		116,677,688	110,243,500			116,677,688	110,243,500				
28	Other Income and Deductions											
29	Other Income											
30	Nonutility Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)		553,116	507,518								
34	(Less) Expenses of Nonutility Operations (417.1)		361,066	297,581								
35	Nonoperating Rental Income (418)		71,636	71,778								
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		444,285	47,613								
38	Allowance for Other Funds Used During Construction (419.1)		1,199,621	1,690,320								
39	Miscellaneous Nonoperating Income (421)		2,962,042	2,426,076								
40	Gain on Disposition of Property (421.1)		165,433	31,354								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,035,067	4,477,078								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		1,609,368	1,394,823								
46	Life Insurance (426.2)											
47	Penalties (426.3)		601,745									
48	Exp. for Certain Civic, Political & Related Activities (426.4)		295,150	268,921								
49	Other Deductions (426.5)		453,342	460,592								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,959,605	2,124,336								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	7,848	7,848								
53	Income Taxes-Federal (409.2)	262	520,465	555,999								
54	Income Taxes-Other (409.2)	262	173,340	169,372								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	708,407	864,805								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	945,531	925,966								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		464,529	672,058								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,610,933	1,680,684								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		31,797,400	31,656,650								
63	Amort. of Debt Disc. and Expense (428)		366,910	374,408								
64	Amortization of Loss on Reaquired Debt (428.1)		24,648	100,237								
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)											
68	Other Interest Expense (431)		3,540,380	748,790								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,864,858	930,087								
70	Net Interest Charges (Total of lines 62 thru 69)		33,864,480	31,949,998								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		84,424,141	79,974,186								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes- Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		84,424,141	79,974,186								

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		272,406,309	247,581,325
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		84,424,141	79,974,186
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Excess hydro licensing amortization		(270,380)	(204,807)
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(270,380)	(204,807)
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1			(58,385,674)	(54,944,395)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(58,385,674)	(54,944,395)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		298,174,396	272,406,309
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		1,391,921	1,121,541
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,391,921	1,121,541
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		299,566,317	273,527,850
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

STATEMENT OF CASH FLOWS

- Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
- Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
- Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
- Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	84,424,141	79,974,186
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	68,697,443	65,172,010
5	Amortization of (Specify) (footnote details)		
5.1	Amortization	4,663,356	3,936,266
5.2	Vehicle depreciation allocated to various operating accounts	2,360,133	2,342,895
8	Deferred Income Taxes (Net)	25,282,218	33,111,295
9	Investment Tax Credit Adjustment (Net)	(744,518)	(744,523)
10	Net (Increase) Decrease in Receivables	7,043,535	(3,525,171)
11	Net (Increase) Decrease in Inventory	(8,087,402)	(8,484,629)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(10,012,269)	19,433,230
14	Net (Increase) Decrease in Other Regulatory Assets	12,479,077	28,808,084
15	Net Increase (Decrease) in Other Regulatory Liabilities	20,972,715	(1,816,894)
16	(Less) Allowance for Other Funds Used During Construction	1,199,621	1,690,320
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other: (increase) decrease in assets and deferred debits	(6,670,169)	3,060,644
18.2	Other: increase (decrease) in liabilities and deferred cost	(18,575,815)	(60,086,837)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	180,632,824	159,490,236
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(241,946,769)	(149,431,971)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	51,898	
30	(Less) Allowance for Other Funds Used During Construction	(1,199,621)	(1,690,320)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(240,695,250)	(147,741,651)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,299,857	
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)	(200,817)	
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		560,931
53	Other (provide details in footnote):		
53.1	Other: (increase) decrease in funds on deposit with trustee	4,709,898	(6,932,043)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(234,886,312)	(154,112,763)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		90,000,000
62	Preferred Stock		
63	Common Stock	40,000,000	
64	Other (provide details in footnote):		
64.1	Other: debt issuance expense		(286,756)
66	Net Increase in Short-Term Debt (c)	73,218,121	
67	Other (provide details in footnote):		
67.1	Other: change in checks written in excess of cash	(565,265)	178,897
67.2	Other: proceeds from capital infusions		50,000,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	112,652,856	139,892,141
72	Payments for Retirement of:		
73	Long-term Debt (b)		(30,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)		(60,322,006)
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(58,385,674)	(54,944,395)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	54,267,182	(5,374,260)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	13,694	3,213
88	Cash and Cash Equivalents at Beginning of Period	17,996	14,783
90	Cash and Cash Equivalents at End of Period	31,690	17,996

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

1. Summary of Significant Accounting Policies

Overview

Otter Tail Power Company ("OTP", the "Company", "us", "our" or "we"), a wholly owned subsidiary of Otter Tail Corporation, with headquarters in Fergus Falls, Minnesota, is a vertically integrated, regulated utility with generation, transmission and distribution facilities to provide electricity to more than 130,000 customers in a service area encompassing approximately 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. Our service territory is predominantly rural and agricultural and includes over 400 communities, most of which have populations of less than 10,000.

In addition to retail revenue, we are also a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets allowing us to transmit electricity for others over the transmission assets we wholly or jointly own and to sell electricity we generate into the wholesale electricity market.

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and this report differs from Generally Accepted Accounting Principles (GAAP). The significant differences consist of the following:

- Earnings per share, as determined under GAAP, are not reported herein
- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Various revenues and expenses are presented as other income and income deductions for FERC presentation and reported as operating income and expenses for the GAAP presentation.
- Revenue is classified in the Income Statement as Operating Revenue based on FERC account, while GAAP presentation reflects revenue as either revenue from contract with customers or alternative revenue programs.
- A portion of the non-service benefit costs are capitalized and included in rate base additions for rate recovery for regulatory treatment, while GAAP presentation reflects these costs as non-operating expenses.
- No operating lease assets or liabilities are recognized under FERC. An operating lease right-of-use asset and lease liability are recognized for most operating leases under GAAP.
- Capitalized cloud computing costs are reported in FERC accounts for utility plant, while GAAP presentation reflects these costs as other noncurrent assets.

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

We are subject to regulation of rates and other matters by state utility commissions in Minnesota, North Dakota and South Dakota and by the Federal Energy Regulatory Commission (FERC) for certain interstate operations. We account 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 statements of 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 statements of 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 comprehensive income at the time they are reflected in customer rates. In the event we cease 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 balance sheets and included in the statements of comprehensive 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 maturities of 90 days or less to be cash equivalents.

Revenue from Contracts with Customers

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. We recognize revenue over time for the delivery or transmission of electricity or related services. Sales or other taxes collected from customers are excluded from operating revenues.

Most revenues are earned from the generation, transmission and sale of electricity to retail customers at rates approved by state regulatory commissions. We also earn revenue from the transmission of electricity for others over the transmission assets we own 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 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, we record revenue and an unbilled receivable based on estimates of the amount of energy delivered to the customer.

Receivables and Allowance for Credit Losses

We grant credit to our customers in the normal course of business with repayment terms generally 30 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 of inventories, which consist of fuel, materials and supplies, are determined on an average cost basis.

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. The amount of interest capitalized to electric plant was \$1.9 million in 2023 and \$0.9 million in 2022. 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.

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

(years)	Service Life Range	
	Low	High
Electric Assets:		
Production Plant	21	114
Transmission Plant	51	75
Distribution Plant	10	70
General Plant	5	56

Jointly Owned Facilities

We are 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. We are also a joint owner, with other regional utilities, in five major transmission lines. Our interest in each jointly owned facility is reflected in the balance sheets on a pro-rata basis and our share of direct revenue and expenses are included in operating revenues and expenses in the statements of comprehensive income. Each participant in the jointly owned facilities finances their own investment.

Recoverability of Long-Lived Assets

We review our long-lived assets including, among other assets, property, plant and equipment, 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.

Employee Benefit Plans

Current and retired employees of OTP participate in a funded pension plan, an unfunded supplemental pension plan, a postretirement healthcare plan and certain nonqualified deferred compensation plans sponsored by Otter Tail Corporation. We have elected to recognize our estimated proportionate share of the assets, where applicable, and liabilities of these plans in our balance sheets, and to recognize the allocated share of the cost of these plans in our statements of comprehensive income. Generally, the allocation to recognize our proportionate share of assets, liabilities and cost of the plans is based on relative headcount of employees participating in each respective plan.

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 (accrion). ARO estimates are revised periodically with any adjustment reflected in the ARO and associated long-lived asset.

Income Taxes

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. We have elected to use a modified separate return method to record income taxes in these financial statements. Under this method, we recognize current and deferred tax expense and tax assets and liabilities as if we filed separate income tax returns. We modify the separate return method only in our assessment of the realizability of our deferred tax assets, in which we assess realizability based on future sources of taxable income of Otter Tail Corporation and its subsidiaries.

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 by Otter Tail Corporation and its subsidiaries. The realizability of deferred tax assets is determined by taking into consideration for Otter Tail Corporation and its subsidiaries 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 have elected to account for transferable tax credits as a component of our income tax provision. We recognize the benefit of PTCs as a reduction of income tax expense in the period the credit is generated, which corresponds to the period the energy production occurs. 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.

Deferred Compensation Plans

Otter Tail Corporation sponsors two nonqualified deferred compensation plans for the benefit of executive officers and other select employees, including certain OTP officers and employees. Each plan allows participants to defer a specified amount or percentage of base wages or incentive compensation into the plan, subject to certain limitations. OTP, at its discretion, may make employer contributions to either plan during any annual period. Participant and employer deferred amounts are segregated into one or more accounts chosen by the participant. Participants earn a return on deferred amounts based on notional investments in the segregated accounts. Participants can elect lump sum distributions or annual installments of deferred balances during the participant's employment or upon retirement. As of December 31, 2023 and 2022, our liability to participants under these deferred compensation plans was \$3.0 million and \$2.5 million. OTP contributions to these plans were \$0.3 million and \$0.2 million for the years ended December 31, 2023 and 2022. Gains or (losses) recognized due to changes in our payment obligations in connection with these plans amounted to \$(0.3 million) and \$0.2 million for the years ended December 31, 2023 and 2022.

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 a lignite service agreement (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 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 we are not required to include CCMC in our 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, our maximum loss exposure, as a result of our involvement with CCMC, could be as high as \$40 million, our 35% share of CCMC's unrecovered costs as of December 31, 2023, if recovery of such a loss is denied by regulatory authorities.

Recent Accounting Pronouncements

Income Taxes. In December 2023, the FASB issued amended authoritative guidance codified in ASC 740, Income Taxes. The amended guidance requires additional disaggregated information in effective tax rate reconciliation disclosures and additional disaggregated information about income taxes paid. The updated standard is effective for our annual periods beginning in 2026, and early adoption is permitted. The amended guidance is to be applied on a prospective basis with the option to apply the standard retrospectively. We are currently evaluating the impact that the updated standard will have on our financial statement disclosures.

Subsequent Events

We have considered events for recognition or disclosure in the financial statements that occurred subsequent to December 31, 2023 through March 6, 2024, the date the GAAP financial statements were available for issuance, and through April 16, 2024 for all circumstances that would require disclosure. Management is not aware of any material subsequent events that would require recognition or disclosure in the 2023 financial statements except as disclosed in note 14.

2. Receivables

Receivables as of December 31, 2023 and 2022 are as follows:

(in thousands)	2023	2022
Receivables		
Trade	\$ 22,301	\$ 25,439
Other	8,385	9,444
Unbilled Receivables	21,324	23,932
Total Receivables	52,010	58,815
Less Allowance for Credit Losses	1,548	1,310
Receivables, net of allowance for credit losses	\$ 50,462	\$ 57,505

The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2023 and 2022:

(in thousands)	2023	2022
Beginning Balance, January 1	\$ 1,310	\$ 1,647
Additions Charged to Expense	1,376	760
Reductions for Amounts Written Off, Net of Recoveries	(1,138)	(1,097)
Ending Balance, December 31	\$ 1,548	\$ 1,310

3. Regulatory Matters

Regulatory Assets and Liabilities

The following presents our regulatory assets and liabilities as of December 31, 2023 and 2022 and the period we expect to recover or refund such amounts:

(in thousands)	Period of Recovery/Refund	December 31, 2023	December 31, 2022
Regulatory Assets			
Asset Retirement Obligations ¹	Asset lives	\$ 10,617	\$ 11,590
Pension and Other Postretirement Benefit Plans ¹ - see below	Various	86,288	87,528
Revenue Recovery Riders	Up to 2 years	3,876	8,186
ISO Cost Recovery Trackers ³	Up to 2 years	467	890
Deferred Rate Case Expenses ¹	Up to 3 years	1,208	1,131
Fuel Clause Adjustment ¹	Up to 1 year	7,294	10,893
Derivative Instruments	Up to 1 year	4,210	7,130
Other ²	Various	6,940	—
Total Regulatory Assets		\$ 120,900	\$ 127,349
Regulatory Liabilities			
Deferred Income Taxes	Asset lives	\$ 136,022	\$ 131,480
Pension and Other Postretirement Benefit Plans	Various	17,086	5,590
Fuel Clause Adjustment	Up to 1 year	11,350	365
Revenue Recovery Riders	Various	19,566	9,967
ISO Cost Recovery Trackers	Up to 2 years	359	15
Derivative Instruments	Various	—	—
Other	Various	183	139
Total Regulatory Liabilities		\$ 184,567	\$ 147,556

¹Costs subject to recovery without a 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.

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.

Fuel Clause Adjustments represent the under- or over-collection of fuel costs relative to the estimated cost of fuel included in customer rates, which will be collected from or returned to customers.

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.

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

North Dakota PTC Refunds represent PTCs earned at the Merricourt Wind Energy Center. These amounts are being allocated to customers over the life of the asset.

Other regulatory assets and liabilities include other amounts that we expect to recover from, or return to, customers in future periods, such as the cost of abandoned projects, costs incurred in connection with recent rate cases, and other items.

North Dakota Rate Case

On November 2, 2023, we filed a request with the North Dakota Public Service Commission (NDPSC) for an increase in revenue recoverable under general rates in North Dakota. In our filing, we requested a net increase in annual revenue of \$17.4 million, or 8.4%, based on an allowed rate of return on rate base of 7.85% and an allowed rate of return on equity of 10.6% on an equity ratio of 53.5% of total capital. Through this proceeding, we have proposed changes to the mechanism of cost and investment recovery, with recovery moving from riders into base rates. The filing also includes a proposal to implement a sales adjustment mechanism to address potential significant load additions or losses. The filing included an interim rate request of a net increase in annual revenue of \$12.4 million, or 6.0%, which was approved by the NDPSC on December 13, 2023, and interim rates went into effect on January 1, 2024. These interim rate revenues, when collected, are subject to potential refund until the finalization of the rate case.

4. Electric Plant

Major classes of electric plant as of December 31, 2023 and 2022 include:

(in thousands)	December 31, 2023	December 31, 2022
Electric Plant in Service		
Electric Plant in Service	\$ 3,024,574	\$ 2,851,417
Construction Work in Progress	146,672	118,375
Total Gross Electric Plant	3,171,246	2,969,791
Less Accumulated Depreciation and Amortization	1,009,079	985,407
Net Electric Plant	\$ 2,162,167	\$ 1,984,384

Depreciation expense for the years ended December 31, 2023 and 2022 totaled \$72.3 million and \$67.5 million.

The following table provides our ownership percentages and amounts included in the December 31, 2023 and 2022 balance sheets for our 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, 2023					
Big Stone Plant	53.9 %	\$ 341,683	\$ 820	\$ (126,904)	\$ 215,599
Coyote Station	35.0 %	188,656	104	(115,306)	73,454
Big Stone South—Ellendale 345 kV line	50.0 %	106,185	—	(7,181)	99,004
Fargo—Monticello 345 kV line	14.2 %	78,184	—	(11,238)	66,946
Big Stone South—Brookings 345 kV line	50.0 %	53,170	—	(5,207)	47,963
Brookings—Southeast Twin Cities 345 kV line	4.8 %	26,409	83	(3,617)	22,875
Bemidji—Grand Rapids 230 kV line	14.8 %	16,331	—	(3,568)	12,763
Jamesstown—Ellendale 345 kV line	50.0 %	—	1,121	—	1,121
Big Stone South—Alexandria 345 kV line	40.0 %	—	555	—	555
Alexandria—Big Oaks 345 kV line	14.2 %	—	343	—	343
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

5. Short-Term and Long-Term Borrowings

Short-Term Debt

The following is a summary of our line of credit as of December 31, 2023 and 2022:

(in thousands)	Line Limit	2023		2022	
		Amount Outstanding	Letters of Credit	Amount Available	Amount Available
OTP Credit Agreement	170,000	81,422	9,132	79,446	152,223

OTP is party to a Fourth Amended and Restated Credit Agreement. The agreement provides for a \$170.0 million unsecured revolving line 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 \$50.0 million. The credit facility includes an accordion provision allowing us to increase the borrowing capacity under the facility, subject to certain conditions, up to \$250.0 million.

Borrowings under the 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 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 agreement, selected by us at the time of an advance, subject to the conditions of the agreement, plus an applicable credit spread. The credit spread ranges from zero to 1.75%, depending on the benchmark interest rate selected and is subject to adjustment based on our credit ratings. The weighted-average interest rate on all outstanding borrowings as of December 31, 2023 and 2022 was 6.70% and 5.61%.

The credit facility contains a number of restrictions, 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 agreement also requires us to maintain various financial covenants, as further described below.

Long-Term Debt

The following is a summary of outstanding long-term debt as of December 31, 2023 and 2022:

Debt Instrument	Rate	Maturity	(in thousands)	
			December 31, 2023	December 31, 2022
Series 2007C Senior Unsecured Notes	6.37%	08/02/27	\$ 42,000	\$ 42,000
Series 2013A Senior Unsecured Notes	4.68%	02/27/29	60,000	60,000
Series 2019A Senior Unsecured Notes	3.07%	10/10/29	10,000	10,000
Series 2020A Senior Unsecured Notes	3.22%	02/25/30	10,000	10,000
Series 2020B Senior Unsecured Notes	3.22%	08/20/30	40,000	40,000
Series 2021A Senior Unsecured Notes	2.74%	11/29/31	40,000	40,000
Series 2007D Senior Unsecured Notes	6.47%	08/20/37	50,000	50,000
Series 2019B Senior Unsecured Notes	3.52%	10/10/39	26,000	26,000
Series 2020C Senior Unsecured Notes	3.62%	02/25/40	10,000	10,000
Series 2013B Senior Unsecured Notes	5.47%	02/27/44	90,000	90,000
Series 2018A Senior Unsecured Notes	4.07%	02/07/48	100,000	100,000
Series 2019C Senior Unsecured Notes	3.82%	10/10/49	64,000	64,000
Series 2020D Senior Unsecured Notes	3.92%	02/25/50	15,000	15,000
Series 2021B Senior Unsecured Notes	3.69%	11/29/51	100,000	100,000
Series 2022A Senior Unsecured Notes	3.77%	05/20/52	90,000	90,000
Total			\$ 747,000	\$ 747,000

Our unsecured notes require us 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 us, including our 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.

Maturities of long-term debt obligations as of December 31, 2023 for each of the next five years were as follows:

(in thousands)	2024	2025	2026	2027	2028
Debt Maturities	\$ —	\$ —	\$ —	\$ 42,000	\$ —

Financial Covenants

Certain of our short-term and long-term debt agreements require us 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, 2023, we were in compliance with these financial covenants.

6. Employee Postretirement Benefits

Certain of our employees participate in benefit plans sponsored by Otter Tail Corporation, including a noncontributory funded pension plan (the "Pension Plan"), an unfunded, nonqualified Executive Survivor and Supplemental Retirement Plan (the "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 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 OTP or Otter Tail Corporation.

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 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. Otter Tail Corporation has established a Retirement Plans Administration Committee to develop and monitor our investment strategy for the Pension Plan assets. The 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, 2023 and 2022:

Asset Class	Permitted Range		Actual Allocation	
	2023	2022	2023	2022
Return Enhancement	35 — 60 %	48 %	48 %	48 %
Risk Management	40 — 80 %	51	51	51
Alternatives	0 — 20 %	1	1	1
Total		100 %	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, 2023 and 2022 and assets measured using the net asset value (NAV) practical expedient:

(in thousands)	Level 1	Level 2	Level 3	NAV	Total
December 31, 2023					
Equity Funds	\$ 123,854	\$ —	\$ —	\$ —	\$ 123,854
Fixed Income Funds	163,246	—	—	—	163,246
Hybrid Funds	10,694	—	—	—	10,694
U.S. Treasury Securities	22,615	—	—	—	22,615
SEI Energy Debt Collective Fund	—	—	—	1,478	1,478
Total	320,409	—	—	1,478	321,887
December 31, 2022					
Equity Funds	121,219	—	—	—	121,219
Fixed Income Funds	152,513	—	—	—	152,513
Hybrid Funds	9,512	—	—	—	9,512
U.S. Treasury Securities	19,098	—	—	—	19,098
SEI Energy Debt Collective Fund	—	—	—	3,611	3,611
Total	\$ 302,342	\$ —	\$ —	\$ 3,611	\$ 305,953

The investments held by the SEI Energy Debt Collective Fund on December 31, 2023 and 2022 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, 2023 and 2022 and the funded status of the plans as of December 31, 2023 and 2022:

A reconciliation of the carrying amounts of AROs for the years ended December 31, 2023 and 2022 are as follows:

(in thousands)	2023		2022	
Beginning Balance		\$ 25,182	\$	24,191
New Obligations Recognized		4,506		—
Adjustments Due to Revisions in Cash Flow Estimates		8,394		—
Accrued Accretion		1,191		991
Settlements		(2,796)		—
Ending Balance		\$ 36,477	\$	25,182

8. Income Taxes

Income before income taxes for the years ended December 31, 2023 and 2022 consists entirely of domestic earnings.

The provision for income taxes charged to income for the years ended December 31, 2023 and 2022 consisted of the following:

(in thousands)	2023		2022	
Current				
Federal Income Taxes		\$ (20,376)	\$	(22,475)
State Income Taxes		(2,669)		(3,835)
Deferred				
Federal Income Taxes		17,337		22,010
State Income Taxes		7,945		9,954
Tax Credits				
North Dakota Wind Tax Credit Amortization, Net of Federal Taxes		(586)		(586)
Investment Tax Credit Amortization		(3)		(3)
Total		\$ 1,648	\$	5,065

The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2023 and 2022 is as follows:

	2023		2022	
Income Taxes at Federal Statutory Rate	\$	18,075	\$	17,858
Increases (Decreases) in Tax from:				
State Taxes on Income, Net of Federal Tax		4,327		4,283
Production Tax Credits (PTCs)		(17,394)		(14,985)
Amortization of Excess Deferred Income Taxes		(2,205)		(1,625)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		(586)		(586)
Allowance for Equity Funds Used During Construction		(312)		(440)
Other, Net		(257)		560
Income Taxes Expense / Effective Tax Rate	\$	1,648	\$	5,065
		21.0%		21.0%

PTCs, North Dakota wind tax credits, and excess deferred income taxes related to the federal tax rate reduction in the 2017 Tax Cuts and Jobs Act are returned to customers as a reduction of the rates they are charged and result in a reduction of operating revenues.

Deferred tax assets and liabilities were composed of the following on December 31, 2023 and 2022:

(in thousands)	2023		2022	
Deferred Tax Assets				
Tax Credit Carryforward		\$ 43,088	\$	55,113
Other Employee Benefits		20,204		21,037
Differences Related to Property		7,964		7,703
Cost of Removal		32,993		37,360
Net Operating Loss Carryforward		—		170
Regulatory Asset – FAS 109		2,956		2,677
Other		(1,500)		(1,823)
Total Deferred Tax Assets		105,705		122,237
Deferred Tax Liabilities				
Differences Related to Property		(295,498)		(281,653)
Pension Expense		(25,264)		(24,805)
North Dakota Wind Tax Credits		(5,297)		(6,111)
Regulatory Liability		(2,262)		(2,231)
Impact of State Net Operating Losses on Federal Taxes		—		(36)
Other		(374)		(2,743)
Total Deferred Tax Liabilities		(328,695)		(317,579)
Deferred Income Taxes		\$ (222,990)	\$	(195,342)

The following is a schedule of tax credits available as of December 31, 2023 and the respective periods of expiration:

(in thousands)	Amount		2024-2037		2038-2045	
Federal Tax Credits	\$	14,697	\$	—	\$	14,697
State Tax Credits		23,094		—		23,094

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2023 and 2022, \$17.0 million and \$25.2 million of net operating loss and tax credit carryforwards were used, or expected to be used, in the consolidated income tax returns. Under the tax sharing agreement between Otter Tail Corporation and OTP, we are paid on an annual basis for the use of these tax attributes in the consolidated income tax returns. Accordingly, these tax assets will not be available to reduce future cash taxes.

As of December 31, 2023 and 2022, we had no unrecognized tax benefits. As of December 31, 2023, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2020 for federal and North Dakota income taxes and prior to 2019 for Minnesota state income taxes.

9. Commitments and Contingencies

Commitments

Construction and Other Commitments. As of December 31, 2023, we had commitments under contracts for construction project materials, plant maintenance and other services extending into 2046 which totaled approximately \$9.2 million.

Electric Utility Capacity and Energy Requirements. We have commitments for the purchase of capacity and energy requirements under contractual agreements, including wind power purchase agreements extending into 2048. Generally, the terms of our wind power purchase agreements require us 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 \$5.6 million and \$13.1 million for the years ended December 31, 2023 and 2022.

Coal Purchase Commitments. We have contracts providing for the purchase and delivery of our coal requirements. Our 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. We have 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 \$43.7 million and \$45.1 million for the years ended December 31, 2023 and 2022.

Land Easement Payments. We have commitments to make payments for land easements not classified as leases. The contractual terms of these easements are generally 99 years or do not have a stated maturity date, however, per the terms of the agreements, our requirements to make payments end once we cease use of the land. As such, in the table below, we have included payments under these easements through the estimated useful lives of the facilities associated with the easement. The commitments under these arrangements extend into 2055 and total approximately \$62.4 million. Land easement costs under these agreements totaled \$1.8 million and \$1.4 million for the years ended December 31, 2023 and 2022.

Our future commitments as of December 31, 2023 were as follows:

(in thousands)	Construction Program and Other Commitments		Capacity and Energy Requirements		Coal Purchase Commitments		Land Easement Payments	
2024	\$	1,013	\$	245	\$	24,691	\$	1,804
2025		555		217		24,593		1,840
2026		479		197		25,374		1,845
2027		487		197		25,786		1,882
2028		495		197		25,344		1,921
Beyond 2028		6,165		3,939		359,610		53,107
Total	\$	9,194	\$	4,992	\$	485,398	\$	62,399

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 \$2.8 million as of December 31, 2023. 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 (EPA) 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, our 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 (SIP). The NDDAQ submitted its SIP to the EPA for approval in August 2022. In its plan, the NDDAQ concluded it is not reasonable to require additional emission controls during this planning period. The EPA has previously expressed disagreement with the NDDAQ'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 SIP may have on our business until the SIP 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 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.

As a transmission owner in MISO, we have exercised our authority and elected to self-fund previous transmission upgrades necessary to accommodate new system generation. Under such an election, we are 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 operating results, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2023 will not be material.

10. Accumulated Other Comprehensive Income (Loss)

Our other comprehensive income consists of unamortized actuarial losses and prior service costs related to pension and other postretirement benefits. The income tax expense or benefit associated with amounts reclassified from accumulated other comprehensive income (loss) and reflected in the statements of comprehensive income are recognized in the same period as the amounts are reclassified.

The following table shows the changes in accumulated other comprehensive loss related to our Pension and Other Postretirement Benefits for the years ended December 31, 2023 and 2022:

<i>(in thousands)</i>	2023		2022	
Balance, Beginning of Period	\$	(1,086)	\$	(2,799)
Other Comprehensive Income (Loss) Before Reclassifications, net of tax		(115)		1,987
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) ⁽¹⁾		24		(274)
Total Other Comprehensive Income (Loss)		(91)		1,713
Balance, End of Period	\$	(1,177)	\$	(1,086)

⁽¹⁾ Included in the computation of net periodic pension and other postretirement benefit costs. See Note 8 for further information.

11. Dividend Restrictions

Our credit agreements 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, 2023, 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 Minnesota Public Utilities Commission (MPUC) indirectly limits the amount of dividends we can pay to Otter Tail Corporation by requiring an equity-to-total-capitalization ratio between 48.3% and 59.1%, with total capitalization not to exceed \$2.0 billion based on our capital structure requirements as of December 31, 2023. As of December 31, 2023, our equity-to-total-capitalization ratio, including short-term debt, was 54.2% and our net assets restricted from distribution totaled approximately \$771.3 million.

12. Derivative Instruments

We enter into derivative instruments to manage our exposure to future commodity price variability, specifically future wholesale energy and natural gas prices, and reduce volatility in prices for our retail customers. These derivative instruments are not designated as qualifying hedging transactions but provide for an economic hedge against future price variability. These instruments are recorded at fair value on our balance sheets. 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, 2023 and 2022, we had outstanding pay-fixed, receive-variable swap agreements with an aggregate notional amount of 187,400 and 295,000 megawatt-hours of electricity. The contracts outstanding as of December 31, 2023 had various settlement dates throughout 2024. As of December 31, 2023 and 2022, the fair value of these derivative instruments was \$4.2 million and \$7.1 million, which are included in other current liabilities on our balance sheets. During the years ended December 31, 2023 and 2022, contracts matured and were settled in an aggregate amount of a \$16.5 million loss and a \$1.0 million gain, respectively. Gains and losses recognized on the settlement of derivative instruments are returned to, or recovered from, our electric customers through fuel recovery mechanisms in each state. When recognized in the statements of comprehensive income, these gains or losses are included in electric purchased power.

13. Fair Value of Financial Instruments

The following tables present our assets and liabilities measured at fair value on a recurring basis as of December 31, 2023 and 2022 classified by the input method used to measure fair value:

	Level 1		Level 2		Level 3	
December 31, 2023						
Liabilities:						
Derivative Instruments	\$	—	\$	4,210	\$	—
Total Liabilities	\$	—	\$	4,210	\$	—
December 31, 2022						
Liabilities:						
Derivative Instruments	\$	—	\$	7,130	\$	—
Total Liabilities	\$	—	\$	7,130	\$	—

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 and liabilities recorded at fair value on a recurring basis, we also hold financial instruments that are not recorded at fair value in the 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, 2023 and 2022:

<i>(in thousands)</i>	December 31, 2023				December 31, 2022			
	Carrying Amount		Fair Value		Carrying Amount		Fair Value	
Assets:								
Cash and Cash Equivalents	\$	32	\$	32	\$	18	\$	18
Total	\$	32	\$	32	\$	18	\$	18
Liabilities:								
Short-Term Debt	\$	81,422	\$	81,422	\$	8,204	\$	8,204
Long-Term Debt		747,000		635,398		747,000		608,741
Total	\$	828,422	\$	716,820	\$	755,204	\$	616,945

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 and the 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.

14. Related Party Transactions

Included in the amounts presented in the accompanying balance sheets and statements of comprehensive income as of and for the years ended December 31, 2023 and 2022 are the following related party transaction balances attributable to transactions with Otter Tail Corporation:

<i>(in thousands)</i>	2023		2022	
Accounts Receivable	\$	7	\$	7
Accounts Payable		2,415		3,016
Operating Revenues		26		27
Operating and Maintenance Expenses		13,743		13,031

Operating and maintenance expenses predominately relate to the allocation of corporate overhead expenses from Otter Tail Corporation, including items such as labor, professional services, subscriptions, information technology and general office expenses. Operating revenues arise from rent charged to Otter Tail Corporation for office space usage.

Otter Tail Corporation pays OTP for certain tax credits and other tax benefits it generates, which are realized through the filing of Otter Tail Corporation's consolidated tax returns. We received \$24.3 million and \$26.5 million during the years ended December 31, 2023 and 2022, respectively, from Otter Tail Corporation in exchange for these tax credits and other tax benefits. In January and February of 2024, OTP received payments totaling \$17.0 million from Otter Tail Corporation in exchange for certain tax credits and other tax benefits.

The Otter Tail Power Company Foundation is an independent not-for-profit charitable entity affiliated with OTP and is not included in our financial statements. Contribution obligations to the foundation totaling \$1.5 million and \$1.3 million were recognized as of December 31, 2023 and 2022. Cash contributions paid to the foundation during the years ended December 31, 2023 and 2022 were \$1.3 million and \$1.5 million.

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2) <input type="checkbox"/> A Resubmission		

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(2,798,909)			(2,798,909)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value				1,712,904			1,712,904		
4	Total (lines 2 and 3)				1,712,904			1,712,904	79,974,186	81,687,090
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,086,005)			(1,086,005)		
6	Balance of Account 219 at Beginning of Current Year				(1,086,005)			(1,086,005)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value				(90,913)			(90,913)		
9	Total (lines 7 and 8)				(90,913)			(90,913)	84,424,141	84,333,228
10	Balance of Account 219 at End of Current Quarter/Year				(1,176,918)			(1,176,918)		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	2,409,543,663	2,409,543,663					
4	Property Under Capital Leases							
5	Plant Purchased or Sold							
6	Completed Construction not Classified	614,828,198	614,828,198					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	3,024,371,861	3,024,371,861					
9	Leased to Others							
10	Held for Future Use	12,038	12,038					
11	Construction Work in Progress	146,671,993	146,671,993					
12	Acquisition Adjustments	190,479	190,479					
13	Total Utility Plant (8 thru 12)	3,171,246,371	3,171,246,371					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,009,079,480	1,009,079,480					
15	Net Utility Plant (13 less 14)	2,162,166,891	2,162,166,891					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	992,301,265	992,301,265					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	15,131,912	15,131,912					
22	Total in Service (18 thru 21)	1,007,433,177	1,007,433,177					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	1,646,303	1,646,303					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,009,079,480	1,009,079,480					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: UtilityPlantInServiceClassified

Per its FERC-approved tariff, the Company uses a 13-month average of gross electric plant in service for rate-making purposes, illustrated as follows for the current year:

	Gross Electric Plant In Service
December 31, 2022	2,314,916,778
January 31, 2023	2,320,786,378
February 28, 2023	2,323,728,059
March 31, 2023	2,327,799,534
April 30, 2023	2,331,247,888
May 31, 2023	2,335,413,421
June 30, 2023	2,344,297,352
July 31, 2023	2,350,473,963
August 31, 2023	2,357,717,939
September 30, 2023	2,363,950,949
October 31, 2023	2,367,549,274
November 30, 2023	2,453,676,970
December 31, 2023	2,409,543,663
13-month average for rate-making	2,353,930,936

(b) Concept: UtilityPlantInServiceCompletedConstructionNotClassified

Per its FERC-approved tariff, the Company uses a 13-month average of Gross Plant Not Classified for rate-making purposes, illustrated as follows for the current year:

	Gross Plant Not Classified
December 31, 2022	534,840,722
January 31, 2023	615,686,433
February 28, 2023	619,588,505
March 31, 2023	623,776,007
April 30, 2023	627,901,310
May 31, 2023	626,896,284
June 30, 2023	622,852,983
July 31, 2023	620,234,992
August 31, 2023	676,871,849
September 30, 2023	678,437,401
October 31, 2023	682,627,520
November 30, 2023	603,294,559
December 31, 2023	614,828,198
13-month average for rate-making	626,756,674

(c) Concept: ConstructionWorkInProgress

Per its FERC-approved tariff, the Company uses a 13-month average of CWIP for rate-making purposes, illustrated as follows for the current year:

	CWIP
December 31, 2022	118,374,711
January 31, 2023	124,604,714
February 28, 2023	130,053,978
March 31, 2023	133,406,564
April 30, 2023	139,084,086
May 31, 2023	140,273,144
June 30, 2023	147,998,417
July 31, 2023	167,569,422
August 31, 2023	136,582,454
September 30, 2023	137,351,398
October 31, 2023	142,584,100
November 30, 2023	146,571,177
December 31, 2023	146,671,993
13-month average for rate-making	139,317,397

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

- Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
- If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
- Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
- For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
- For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	1,998,445					1,998,445
4	(303) Miscellaneous Intangible Plant	29,998,600	6,415,136				36,413,736
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	31,997,045	6,415,136				38,412,181
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	1,654,157					1,654,157
9	(311) Structures and Improvements	121,556,588	348,104	5,667,110		(475,049)	115,762,533
10	(312) Boiler Plant Equipment	355,488,566	3,022,434	38,453,191		(20,117)	320,037,692
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	66,597,673	3,118,484	11,688,760		(8,367)	58,019,030
13	(315) Accessory Electric Equipment	35,977,575	56,444	2,518,844		(264,030)	33,251,145
14	(316) Misc. Power Plant Equipment	7,104,411	147,882	915,345		(294,696)	6,042,252
15	(317) Asset Retirement Costs for Steam Production	2,881,917	3,423,416	555,302			5,750,031
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	591,260,887	10,116,764	59,798,552		(1,062,259)	540,516,840
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	299,623					299,623
28	(331) Structures and Improvements	486,738	889,102	333		496,332	1,871,839
29	(332) Reservoirs, Dams, and Waterways	7,605,919	(234,752)	171,451		11,247	7,210,963
30	(333) Water Wheels, Turbines, and Generators	1,373,867					1,373,867
31	(334) Accessory Electric Equipment	1,094,885	683,869				1,778,754
32	(335) Misc. Power Plant Equipment	435,026				236,547	671,573
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	11,296,058	1,338,219	171,784		744,126	13,206,619
36	D. Other Production Plant						
37	(340) Land and Land Rights	126,762	1,859,899			400	1,987,061
38	(341) Structures and Improvements	46,363,517	6,383,801	20,956		71,562	52,797,924
39	(342) Fuel Holders, Products, and Accessories	7,911,580	(148,785)				7,762,795

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
40	(343) Prime Movers	138,706,970	1,973,584	92,115			140,588,439
41	(344) Generators	481,779,583	69,040,988	4,306,916		1,255,924	547,769,579
42	(345) Accessory Electric Equipment	46,611,436	64,788,199			124,808	111,524,443
43	(346) Misc. Power Plant Equipment	2,287,590	881,358	284		3,955	3,172,619
44	(347) Asset Retirement Costs for Other Production	13,352,416	6,791,625				20,144,041
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	737,139,854	151,570,669	4,420,271		1,456,649	885,746,901
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,339,696,799	163,025,652	64,390,607		1,138,516	1,439,470,360
47	3. Transmission Plant						
48	(350) Land and Land Rights	23,946,988					23,946,988
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements						
50	(353) Station Equipment	182,616,668	6,700,305	12,756		248,206	189,552,423
51	(354) Towers and Fixtures	197,014,928	35,672				197,050,600
52	(355) Poles and Fixtures	168,586,949	8,374,272	2,829,032			174,132,189
53	(356) Overhead Conductors and Devices	185,138,423	9,488,717	1,469,477			193,157,663
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices	103,562	(26,101)				77,461
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	757,407,518	24,572,865	4,311,265		248,206	777,917,324
59	4. Distribution Plant						
60	(360) Land and Land Rights	1,494,657	56,462				1,551,119
61	(361) Structures and Improvements						
62	(362) Station Equipment	95,079,236	5,852,854	396,867		(27,331)	100,507,892
63	(363) Energy Storage Equipment - Distribution						
64	(364) Poles, Towers, and Fixtures	86,786,803	3,737,614	314,282			90,210,135
65	(365) Overhead Conductors and Devices	60,876,491	2,905,055	416,494			63,365,052
66	(366) Underground Conduit		8,219			(8,219)	
67	(367) Underground Conductors and Devices	114,686,119	20,704,225	1,320,214		8,219	134,078,349
68	(368) Line Transformers	129,349,816	7,577,252	1,347,354		27,331	135,607,045
69	(369) Services	64,032,109	2,304,870	39,775			66,297,204
70	(370) Meters	37,976,042	213,555				38,189,597
71	(371) Installations on Customer Premises	9,654,828	652,973	95,763			10,212,038
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	13,235,267	1,984,716	633,027			14,586,956
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	613,171,368	45,997,795	4,563,776			654,605,387
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	1,597,841	78,236	1,287			1,674,790
87	(390) Structures and Improvements	37,307,737	2,915,043	113,191		(4,047)	40,105,542
88	(391) Office Furniture and Equipment	7,658,956	2,018,635	302,085			9,375,506
89	(392) Transportation Equipment	42,448,908	2,795,649	1,379,002			43,865,555
90	(393) Stores Equipment						
91	(394) Tools, Shop and Garage Equipment	5,854,449	933,936	977,200		42,652	5,853,837
92	(395) Laboratory Equipment						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
93	(396) Power Operated Equipment	1,701,526	16,352			31,322	1,749,200
94	(397) Communication Equipment	10,915,353	426,826				11,342,179
95	(398) Miscellaneous Equipment						
96	SUBTOTAL (Enter Total of lines 86 thru 95)	107,484,770	9,184,677	2,772,765		69,927	113,966,609
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	107,484,770	9,184,677	2,772,765		69,927	113,966,609
100	TOTAL (Accounts 101 and 106)	2,849,757,500	249,196,125	76,038,413		1,456,649	3,024,371,861
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	2,849,757,500	249,196,125	76,038,413		1,456,649	3,024,371,861

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

FOOTNOTE DATA

(a) Concept: IntangiblePlant

Per its FERC-approved tariff, the Company uses a 13-month average of intangible electric plant in service for rate-making purposes, illustrated as follows for the current year:

	Intangible Electric Plant in Service
December 31, 2022	31,997,045
January 31, 2023	31,997,045
February 28, 2023	31,997,045
March 31, 2023	35,586,031
April 30, 2023	35,839,191
May 31, 2023	35,879,979
June 30, 2023	36,683,148
July 31, 2023	37,285,657
August 31, 2023	37,288,769
September 30, 2023	37,942,489
October 31, 2023	37,951,036
November 30, 2023	37,951,036
December 31, 2023	38,412,181
13-month average for rate-making	35,908,512

(b) Concept: ProductionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of production plant in service for rate-making purposes, illustrated as follows for the current year:

	Production Plant in Service
December 31, 2022	1,339,696,799
January 31, 2023	1,424,094,241
February 28, 2023	1,424,249,696
March 31, 2023	1,424,226,828
April 30, 2023	1,426,403,309
May 31, 2023	1,426,010,730
June 30, 2023	1,422,842,749
July 31, 2023	1,423,310,487
August 31, 2023	1,482,226,176
September 30, 2023	1,481,038,248
October 31, 2023	1,484,428,593
November 30, 2023	1,484,937,508
December 31, 2023	1,439,470,360
13-month average for rate-making	1,437,148,902

(c) Concept: TransmissionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of electric transmission plant in service for rate-making purposes, illustrated as follows for the current year:

	Electric Transmission Plant in Service
December 31, 2022	757,407,518
January 31, 2023	758,664,017
February 28, 2023	763,057,616
March 31, 2023	765,729,279
April 30, 2023	767,295,122
May 31, 2023	768,014,463
June 30, 2023	772,846,927
July 31, 2023	773,105,145
August 31, 2023	774,618,198
September 30, 2023	777,015,885
October 31, 2023	776,343,877
November 30, 2023	775,797,581
December 31, 2023	777,917,324
13-month average for rate-making	769,831,766

(d) Concept: DistributionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of distribution plant in service for rate-making purposes, illustrated as follows for the current year:

	Distribution Plant in Service
December 31, 2022	613,171,368
January 31, 2023	614,111,313
February 28, 2023	616,079,600
March 31, 2023	617,231,524
April 30, 2023	620,543,851
May 31, 2023	622,167,425
June 30, 2023	624,503,908
July 31, 2023	626,083,002
August 31, 2023	629,040,457
September 30, 2023	633,805,529
October 31, 2023	638,916,855
November 30, 2023	645,566,446
December 31, 2023	654,605,387
13-month average for rate-making	627,371,282

(e) Concept: GeneralPlant

Per its FERC-approved tariff, the Company uses a 13-month average of general plant in service for rate-making purposes, illustrated as follows for the current year:

	General Plant in Service
December 31, 2022	107,484,770
January 31, 2023	107,606,195
February 28, 2023	107,932,608
March 31, 2023	108,801,878
April 30, 2023	109,067,725
May 31, 2023	110,237,107
June 30, 2023	110,273,603
July 31, 2023	110,924,664
August 31, 2023	111,416,187
September 30, 2023	112,586,198
October 31, 2023	112,536,433
November 30, 2023	112,718,958
December 31, 2023	113,966,609
13-month average for rate-making	110,427,149

(in thousands)	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2023	2022	2023	2022	2023	2022
Change in Fair Value of Plan Assets:						
Fair Value of Plan Assets at January 1	\$ 305,953	\$ 377,532	\$ —	\$ —	\$ —	\$ —
Actual Return on Plan Assets	32,993	(75,073)	—	—	—	—
Company Contributions	—	20,000	1,253	1,625	2,971	2,301
Benefit Payments	(17,059)	(16,506)	(1,253)	(1,625)	(8,636)	(8,118)
Participant Premium Payments	—	—	—	—	5,665	5,817
Fair Value of Plan Assets at December 31	321,887	305,953	—	—	—	—
Change in Benefit Obligation:						
Benefit Obligation at January 1	300,354	406,280	12,216	16,924	48,698	67,578
Service Cost	3,606	6,411	—	—	551	1,305
Interest Cost	16,025	12,035	635	474	2,355	1,990
Benefit Payments	(17,059)	(16,506)	(1,253)	(3,557)	(8,636)	(8,118)
Participant Premium Payments	—	—	—	—	5,665	5,817
Plan Amendments	—	—	—	—	(17,038)	—
Actuarial (Gain) Loss	7,587	(107,866)	204	(1,625)	(2,234)	(19,874)
Benefit Obligation at December 31	310,513	300,354	11,802	12,216	29,361	48,698
Funded Status	\$ 11,374	\$ 5,599	\$ (11,802)	\$ (12,216)	\$ (29,361)	\$ (48,698)
Amounts Recognized in Balance Sheet at December 31:						
Noncurrent Assets	\$ 11,374	\$ 5,599	\$ —	\$ —	\$ —	\$ —
Current Liabilities	—	—	(1,212)	(1,261)	(2,405)	(2,896)
Noncurrent Liabilities and Deferred Credits	—	—	(10,590)	(10,955)	(26,956)	(45,802)
Net Asset (Liability)	\$ 11,374	\$ 5,599	\$ (11,802)	\$ (12,216)	\$ (29,361)	\$ (48,698)

The accumulated benefit obligation of our Pension Plan was \$281.3 million and \$276.1 million as of December 31, 2023 and 2022. The accumulated benefit obligation of our ESSRP was \$11.8 million and \$12.2 million as of December 31, 2023 and 2022.

In 2023, the Company amended its postretirement healthcare plan to eliminate, for Medicare-eligible participants, the employer-sponsored group waiver medical plan and instead allow participants to select an individual medical plan through a private marketplace exchange. The Company now provides these plan participants with an annual reimbursement to subsidize their medical premiums. The effect of the plan amendment reduced OTP's projected benefit obligation by \$19.6 million. The reduced benefit obligation included a \$2.6 million reduction attributable to an increase in the discount rate used to measure the plan liability, which was 6.06% at the time of the amendment, compared to 5.52% used at December 31, 2022. The \$17.0 million of savings attributable to the plan change is being recognized as a reduction to expense over 4.8 years, the expected remaining service period to retirement-age eligibility for active participants.

The following assumptions were used to determine benefit obligations as of December 31, 2023 and 2022:

	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2023	2022	2023	2022	2023	2022
Discount Rate	5.57 %	5.51 %	5.53 %	5.51 %	5.53 %	5.52 %
Long-Term Rate of Compensation Increase	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 ⁽²⁾	4.50 %	3.50 %	n/a	n/a	n/a	n/a
Participants Age 50 and Older ⁽³⁾	3.75 %	2.75 %	n/a	n/a	n/a	n/a
Healthcare Cost Immediate Trend Rate	n/a	n/a	n/a	n/a	6.97 %	7.50 %
Healthcare Cost Ultimate Trend Rate	n/a	n/a	n/a	n/a	4.00 %	4.00 %
Year the Rate Reaches the Ultimate Trend Rate	n/a	n/a	n/a	n/a	2048	2048

⁽¹⁾ Amount reflects rate of compensation increases for both union and non-union employees.

⁽²⁾ Amount reflects rate of compensation increases for union employees. The rate of compensation increases for non-union employees is 3.50%.

⁽³⁾ Amount reflects rate of compensation increases for union employees. The rate of compensation increases for non-union employees is 3.00%.

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 2023 and 2022 reduced our obligation by \$2.1 million and \$114.2 million. Changes in retirement rate, percentage married, spouse age, benefit election, benefit commencement age and wage assumptions increased our benefit obligation in 2023 by \$7.7 million. Changes in plan participant census data increased our benefit obligation by \$3.0 million in 2023. Actual returns on Pension Plan assets in 2023 were \$33.3 million, compared to an expected return of \$25.2 million, impacting our obligation by \$8.1 million.
- For the ESSRP, an increase in the discount rate reduced our obligation by less than \$0.1 million in 2023, and by \$3.5 million in 2022.
- For the postretirement healthcare plan, a plan amendment during 2023, as described above, decreased our benefit obligation by \$17.0 million. An increase in the discount rate in 2023 and 2022 reduced our obligation by \$1.3 million and \$17.5 million. Revised estimates of healthcare cost trends and participant contribution assumptions increased the benefit obligation by \$1.1 million in 2023.

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 statements of comprehensive 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 statements of comprehensive income, nonservice cost components are recognized as nonservice cost components of postretirement benefits.

The following table includes the components of net periodic benefit cost (income) of our defined benefit pension plans and other postretirement benefits for the years ended December 31, 2023 and 2022:

(in thousands)	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2023	2022	2023	2022	2023	2022
Service Cost	\$ 3,606	\$ 6,412	\$ —	\$ —	\$ 551	\$ 1,304
Interest Cost	16,025	12,035	635	474	2,355	1,990
Expected Return on Assets	(25,267)	(23,092)	—	—	—	—
Amortization of Prior Service Cost	—	—	—	—	(6,593)	(5,589)
Amortization of Net Actuarial Loss	—	7,668	—	308	—	2,986
Net Periodic Benefit Cost (Income)	\$ (5,636)	\$ 3,023	\$ 635	\$ 782	\$ (3,687)	\$ 691

The following table includes the impact of regulation on the recognition of periodic benefit cost (income) arising from pension and other postretirement benefits for the years ended December 31, 2023 and 2022:

(in thousands)	2023	2022
Net Periodic Benefit (Cost) Income	\$ (8,688)	\$ 4,496
Net Amount Amortized Due to the Effect of Regulation	1,225	1,121
Net Periodic Benefit (Cost) Income Recognized	\$ (7,463)	\$ 5,617

The following assumptions were used to determine net periodic benefit cost for the years ended December 31, 2023 and 2022:

	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2023	2022	2023	2022	2023	2022
Discount Rate	5.51 %	3.03 %	5.51 %	2.93 %	5.52 %	3.01 %
Long-Term Rate of Return on Plan Assets	7.00 %	6.30 %	n/a	n/a	n/a	n/a
Long-Term Rate of Compensation Increase	n/a	n/a	3.00 %	3.00 %	n/a	n/a
Participants to Age 39	4.50 %	4.50 %	n/a	n/a	n/a	n/a
Participants Ages 40 to 49	3.50 %	3.50 %	n/a	n/a	n/a	n/a
Participants Ages 50 and Older	2.75 %	2.75 %	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, 2023 and 2022:

(in thousands)	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2023	2022	2023	2022	2023	2022
Regulatory Assets:						
Unrecognized Prior Service Cost	\$ —	\$ —	\$ —	\$ —	\$ (18,845)	\$ (8,400)
Unrecognized Actuarial Loss	85,227	85,367	1,061	979	1,759	3,993
Net Regulatory Assets (Liabilities)	\$ 85,227	\$ 85,367	\$ 1,061	\$ 979	\$ (17,086)	\$ (4,407)
Accumulated Other Comprehensive Income (Loss):						
Unrecognized Actuarial Loss	—	—	(1,591)	(1,468)	—	—
Total Accumulated Other Comprehensive Income (Loss)	\$ —	\$ —	\$ (1,591)	\$ (1,468)	\$ —	\$ —

Cash Flows. We did not make any contributions to our Pension Plan in 2023. We made a discretionary contribution to our Pension Plan of \$20.0 million in 2022. As of December 31, 2023, 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)	2024	2025	2026	2027	2028	2029-2033
Projected Pension Plan Benefit Payments	\$ 18,361	\$ 18,773	\$ 19,312	\$ 19,789	\$ 20,339	\$ 107,423
Projected ESSRP Benefit Payments	1,243	1,192	1,147	1,053	997	4,814
Projected Postretirement Benefit Payments	2,405	2,432	2,478	2,481	2,412	11,732
Total	\$ 22,009	\$ 22,397	\$ 22,937	\$ 23,323	\$ 23,748	\$ 123,969

401K Plan

We sponsor a 401K plan for the benefit of all company employees. Contributions made to these plans totaled \$3.9 million for 2023 and \$3.5 million for 2022.

7. Asset Retirement Obligations (AROs)

We have recognized Asset Retirement Obligations (AROs) related to our coal-fired generation plants, natural gas combustion turbines, solar facility, 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. As of December 31, 2023 and 2022, \$0.1 million and \$2.7 million, respectively, was included in other current liabilities and \$36.4 million and \$22.5 million, respectively, was included in other noncurrent liabilities in the balance sheets related to AROs.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
2. For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Various			12,038
21	Other Property:			
22	Various			
47	TOTAL			12,038

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: ElectricPlantHeldForFutureUse

Per its FERC-approved tariff, the Company uses a 13-month average of electric plant held for future use for rate-making purposes, illustrated as follows for the current year:

	Transmission	Distribution	Total
December 31, 2022	9,038	3,000	12,038
January 31, 2023	9,038	3,000	12,038
February 28, 2023	9,038	3,000	12,038
March 31, 2023	9,038	3,000	12,038
April 30, 2023	9,038	3,000	12,038
May 31, 2023	9,038	3,000	12,038
June 30, 2023	9,038	3,000	12,038
July 31, 2023	9,038	3,000	12,038
August 31, 2023	9,038	3,000	12,038
September 30, 2023	9,038	3,000	12,038
October 31, 2023	9,038	3,000	12,038
November 30, 2023	9,038	3,000	12,038
December 31, 2023	9,038	3,000	12,038
13-month average for rate-making			12,038

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	AMI Project Deployment	18,784,476
2	Langdon Repower	13,637,126
3	Ashtabula III Repower	6,739,636
4	Erie 230/115 Substation	6,389,647
5	Winger 230/115kV Transformer	6,068,462
6	Luverne Repower	5,853,529
7	Ashtabula Repower	5,475,156
8	Forman Substation Upgrades Xcel MPF	4,960,502
9	Astoria LTSA 2020-2024	3,727,970
10	Oslo 115kV 5-Breaker Ring Bus Cash	2,461,688
11	GIS - Innovation 2030	2,394,224
12	Storm WO Dist 41.6 kV & Below 2023	2,305,732
13	Oslo - Ardoch 115 Line	2,152,302
14	Casselton NDSP Project	1,740,230
15	Lake City to Eden 41.6kv Rebuild	1,621,944
16	Battle-Otter Outlet East Feed	1,510,485
17	Granville Relocate 41.6kV Line	1,484,894
18	Ottertail-North Feeder Upgrade	1,372,177
19	UI Upgrade with Regulatory Module	1,348,506
20	VQ Milbak 115/12.5 Substation	1,321,591
21	MN Elec Vehicle DCFC Infrastructure	1,298,972
22	Rolla ASB Replacement (2022-2023)	1,218,187
23	AMI - Meters	1,140,770
24	Finley/McVille- Rebuild 41.6	1,138,717
25	JETx Project Develop	1,120,156
26	Central Stores Yard Expansion	1,031,792
27	Total Projects under \$1,000,000	48,373,122
43	Total	146,671,993

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	972,533,783	972,533,783		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	69,343,913	69,343,913		
4	(403.1) Depreciation Expense for Asset Retirement Costs	631,942	631,942		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,360,133	2,360,133		
7	Other Clearing Accounts	(22,887)	*(22,887)		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	72,313,101	72,313,101		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(75,483,110)	(75,483,110)		
13	Cost of Removal	(13,951,254)	(13,951,254)		
14	Salvage (Credit)	31,092,245	31,092,245		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(58,342,119)	(58,342,119)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	9,037,910	*9,037,910		
17.2	Additional Debit or Cr. Items (Describe, details in footnote):	(2,686,108)	(2,686,108)		
18	Book Cost or Asset Retirement Costs Retired	(555,302)	(555,302)		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	992,301,265	*992,301,265		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	260,243,836	260,243,836		
21	Nuclear Production				
22	Hydraulic Production-Conventional	6,567,649	6,567,649		
23	Hydraulic Production-Pumped Storage				
24	Other Production	236,405,187	236,405,187		
25	Transmission	176,421,666	176,421,666		
26	Distribution	264,237,617	264,237,617		
27	Regional Transmission and Market Operation				
28	General	48,425,310	48,425,310		
29	TOTAL (Enter Total of lines 20 thru 28)	992,301,265	*992,301,265		

FOOTNOTE DATA

(a) Concept: OtherClearingAccounts

Inventory costs cleared to construction or utility operating expense.

(b) Concept: OtherAdjustmentsToAccumulatedDepreciation

The net activity during the year for construction/removal not classified

(c) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Per its FERC-approved tariff, the company uses a 13 month average of accumulated depreciation of production, transmission, distribution and general plant for rate-making purposes, illustrated as follows for the current year:

	Production	Transmission	Distribution	General Plant	Total
12/31/2022	503,842,143	169,043,983	254,418,516	45,229,142	972,533,783
1/31/2023	536,358,284	169,872,407	255,629,600	45,533,641	1,007,393,932
2/28/2023	539,392,103	170,796,288	256,652,829	45,960,251	1,012,801,472
3/31/2023	542,652,799	171,417,809	257,734,605	46,260,121	1,018,065,334
4/30/2023	545,820,240	172,408,483	258,705,839	46,543,150	1,023,477,712
5/31/2023	547,884,860	173,180,925	259,596,025	46,965,469	1,027,627,279
6/30/2023	547,547,718	174,187,889	260,429,017	47,204,909	1,029,369,534
7/31/2023	550,518,682	175,040,497	261,133,354	47,598,883	1,034,291,416
8/31/2023	552,986,758	176,310,504	261,701,328	48,075,432	1,039,074,022
9/30/2023	554,382,026	177,059,456	262,432,183	48,551,479	1,042,425,144
10/31/2023	557,550,409	175,944,686	263,488,659	48,912,883	1,045,896,637
11/30/2023	560,916,210	175,952,330	264,394,446	49,057,019	1,050,320,005
12/31/2023	503,216,671	176,421,666	264,237,617	48,425,310	992,301,265
13-month average for rate-making	541,774,531	173,664,379	260,042,617	47,255,207	1,022,736,734

*Production is a total of lines 20 through 24 on page 219.

(d) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Per its FERC-approved tariff, the company uses a 13 month average of accumulated depreciation of production, transmission, distribution and general plant for rate-making purposes, illustrated as follows for the current year:

	Production	Transmission	Distribution	General Plant	Total
12/31/2022	503,842,143	169,043,983	254,418,516	45,229,142	972,533,783
1/31/2023	536,358,284	169,872,407	255,629,600	45,533,641	1,007,393,932
2/28/2023	539,392,103	170,796,288	256,652,829	45,960,251	1,012,801,472
3/31/2023	542,652,799	171,417,809	257,734,605	46,260,121	1,018,065,334
4/30/2023	545,820,240	172,408,483	258,705,839	46,543,150	1,023,477,712
5/31/2023	547,884,860	173,180,925	259,596,025	46,965,469	1,027,627,279
6/30/2023	547,547,718	174,187,889	260,429,017	47,204,909	1,029,369,534
7/31/2023	550,518,682	175,040,497	261,133,354	47,598,883	1,034,291,416
8/31/2023	552,986,758	176,310,504	261,701,328	48,075,432	1,039,074,022
9/30/2023	554,382,026	177,059,456	262,432,183	48,551,479	1,042,425,144
10/31/2023	557,550,409	175,944,686	263,488,659	48,912,883	1,045,896,637
11/30/2023	560,916,210	175,952,330	264,394,446	49,057,019	1,050,320,005
12/31/2023	503,216,671	176,421,666	264,237,617	48,425,310	992,301,265
13-month average for rate-making	541,774,531	173,664,379	260,042,617	47,255,207	1,022,736,734

*Production is a total of lines 20 through 24 on page 219.

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Account 123.1, Investments in Subsidiary Companies.
- Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
- Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
- For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
- If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
- Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
- Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
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33								
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35								
36								
37								
38								
39								
40								
41								

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
42	Total Cost of Account 123.1 \$		Total					

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Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

MATERIALS AND SUPPLIES

- For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
- Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	11,000,592	12,139,789	Production
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	8,472,303	9,483,207	Production
8	Transmission Plant (Estimated)	11,724,877	14,243,402	Various
9	Distribution Plant (Estimated)	12,224,695	16,940,778	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	294,270	327,439	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	32,716,145	40,994,826	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	43,716,737	53,134,615	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: FuelStock

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Fuel Stock
December 31, 2022	11,000,592
January 31, 2023	11,885,742
February 28, 2023	11,611,972
March 31, 2023	11,549,658
April 30, 2023	10,910,673
May 31, 2023	9,662,459
June 30, 2023	10,426,809
July 31, 2023	10,473,211
August 31, 2023	10,495,148
September 30, 2023	10,444,374
October 31, 2023	10,593,590
November 30, 2023	12,635,452
December 31, 2023	12,139,789
13-month average for rate-making	11,063,805

(b) Concept: PlantMaterialsAndOperatingSuppliesProductionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Production Plant
December 31, 2022	8,472,303
January 31, 2023	8,663,743
February 28, 2023	8,776,338
March 31, 2023	8,678,201
April 30, 2023	8,714,220
May 31, 2023	8,744,426
June 30, 2023	8,769,493
July 31, 2023	8,778,479
August 31, 2023	8,816,434
September 30, 2023	8,830,916
October 31, 2023	8,892,653
November 30, 2023	9,168,450
December 31, 2023	9,483,207
13-month average for rate-making	8,829,913

(c) Concept: PlantMaterialsAndOperatingSuppliesTransmissionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Transmission Plant
December 31, 2022	11,724,877
January 31, 2023	11,593,989
February 28, 2023	11,517,603
March 31, 2023	11,951,675
April 30, 2023	12,385,016
May 31, 2023	12,589,398
June 30, 2023	13,220,469
July 31, 2023	14,152,976
August 31, 2023	14,279,970
September 30, 2023	14,537,644
October 31, 2023	14,605,832
November 30, 2023	15,059,795
December 31, 2023	14,243,402
13-month average for rate-making	13,220,204

(d) Concept: PlantMaterialsAndOperatingSuppliesDistributionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Distribution Plant
December 31, 2022	12,224,695
January 31, 2023	12,908,383
February 28, 2023	13,356,873
March 31, 2023	12,954,227
April 30, 2023	12,715,983
May 31, 2023	14,537,871
June 30, 2023	15,313,827
July 31, 2023	16,199,114
August 31, 2023	15,307,940
September 30, 2023	14,863,668
October 31, 2023	16,809,252
November 30, 2023	17,022,984
December 31, 2023	16,940,778
13-month average for rate-making	14,727,354

(e) Concept: PlantMaterialsAndOperatingSuppliesOther

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Assigned to - Other
December 31, 2022	294,270
January 31, 2023	289,821
February 28, 2023	250,445
March 31, 2023	265,105
April 30, 2023	266,987
May 31, 2023	283,505
June 30, 2023	282,367
July 31, 2023	304,481
August 31, 2023	312,661
September 30, 2023	316,240
October 31, 2023	325,973
November 30, 2023	330,285
December 31, 2023	327,439
13-month average for rate-making	296,121

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transfers of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	105,925	111,884	15,310		14,054		14,054		365,404		514,747.00	111,884.00
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									14,054		14,054	
5	Returned by EPA	177										177	
6													
7													
8	Purchases/Transfers:												
9	Renewable Energy Credits												
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	5,204	31,773									5,204	31,773
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	100,898	80,111	15,310		14,054		14,054		379,458		523,774	80,111
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	203		203		203		203		9,945		10,757	
37	Add: Withheld by EPA									406		406	
38	Deduct: Returned by EPA												
39	Cost of Sales	203								203		406	

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year			203		203		203		10,148		10,757	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	203	5							203	4	406	9
45	Gains	203	5							203	4	406	9
46	Losses												

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber

Includes 1,256 of initial allocations from EPA and 3,316 of rollover allowances for Cross State Air Pollution Rule.

(b) Concept: ChargesToAllowancesInventoryNumber

Includes 0 of emission charges for the Cross State Air Pollution Rule.

(c) Concept: AllowanceInventory

Renewable Energy Credits and emissions allowances are held in the Allowance inventory account (158.1) for future use.

	<u>2022</u>	<u>2023</u>
Solar REC Emission Allowance Inventory	90,766	41,789
Co-gen REC Emission Allowance Inventory	21,118,48	38,322
	<u>111,884</u>	<u>80,111</u>

(d) Concept: AllowancesIssuedLessWithheldAllowancesNumber

Includes 0 of initial allocations from EPA for Cross State Air Pollution Rule.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transfers of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	4,832		876									5,708
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA	116											116
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	125											125
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	4,823		876									5,699
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
Page 228(ab)-229(ab)b													

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: AllowanceInventoryNumber

Includes 876 of initial allocations from EPA and 3,956 rollover allowances for Cross State Air Pollution Rule.

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr.)] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not applicable.					
20	TOTAL					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	MPUC order issued 10-6-2020					
22	^(b) Hoot Lake Plant Depreciation - MN	1,154,103		407	76,418	1,077,685
23	^(b) Hoot Lake Hydro Depreciation - MN	156,137		407	10,338	145,799
49	TOTAL	1,310,240			86,756	1,223,484

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts
The MN Hoot Lake Plant Depreciation balance booked to account 18212101 has an amortization period of July 2022 - June 2027.
(b) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts
The MN Hoot Lake Hydro Depreciation balance will be deferred until the next rate case

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
20	Total				
21	Generation Studies				
22	R121 Red Lake County Community Hybrid Study	455	456	455	456
39	Total	455		455	
40	Grand Total	455		455	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: StudyCostsReimbursements

Deposits are received for various studies, however these deposits are not included in the reimbursements column until the costs are incurred. The deposits are recorded to FERC 252 respectively.

FERC FORM No. 1 (NEW. 03-07)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Asset Retirement Obligations-Capitalized:					
2	Hoot Lake Plant	2,725,654	70,716	230	2,796,370	
3	Big Stone Plant	896,173	72,576	407.4	8,599	960,150
4	Coyote Station	3,834,407	321,322			4,155,729
5	Astoria Station	196,276	101,009			297,285
6	Wind Generation - Langdon	1,039,778	163,648			1,203,426
7	Wind Generation - Ashtabula	1,020,835	197,980			1,218,815
8	Wind Generation - Ashtabula III		244,739			244,739
9	Wind Generation - Luverne	1,056,819	212,627			1,269,446
10	Wind Generation - Merricourt	820,141	425,544			1,245,685
11	Hoot Lake Solar		21,633			21,633
12	Post-retirement Benefit Plans:					
13	ESSRP	978,869	81,847	228.3	67	1,060,649
14	Pension	85,366,903		228.3	139,787	85,227,116
15	Post Retirement Medical Benefits	1,182,406	4,275,840	228.3	5,458,246	
16	Alternative Revenue Program Riders:					
17	MN Transmission Cost Recovery Rider Accrued Revenues	1,085,386		See Note	1,085,386	
18	MN Renewable Resource Rider Accrued Revenues	3,196,460	1,314,040	See Note	4,106,863	403,637
19	MN Decoupling	951,335	2,301,138	See Note	653,990	2,598,483
20	Conservation Improvement Program Costs & Incentives - MN	2,559,700	14,128,690	186	16,688,390	
21	Energy Efficiency Program - SD	393,255	246,311	186	436,255	203,311
22	SD Transmission Cost Recovery Rider Accrued Revenues		312,535	See Note	127,541	184,994
23	ND Renewable Resource Rider Accrued Revenues		1,700,162	See Note	1,214,379	485,783
24	ISO Cost Recovery Trackers:					
25	MISO Schedule 26 and 26A Trans Cost Recovery Rider True-up	575,373	719,215	See Note	947,627	346,961
26	SPP Cost Recovery Rider	314,491	85,002	See Note	279,012	120,481
27	Deferred Rate Case Expenses:					
28	MN Deferred Rate Case Expenses Subject to Recovery	1,131,280		407.4	377,093	754,187
29	ND Deferred Rate Case Expenses Subject to Recovery		453,988			453,988
30	Other:					
31	MN Fuel Clause Adjustment	9,942,481		See Note	3,230,715	6,711,766
32	ND Fuel Clause Adjustment		581,744			581,744
33	SD Fuel Clause Adjustment	950,236	1,014,065	See Note	1,964,301	
34	Derivatives Marked-to-Market Losses	7,130,408	4,158,944	244	7,079,370	4,209,982
35	Property/Non Property Related Items		9,116,194	254 & 282	2,175,815	6,940,379
36	See Footnote in Notes to Financial					
44	TOTAL	127,348,666	42,321,509		48,769,806	120,900,369

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Regulatory Asset Description	Docket
Asset Retirement Obligations	RM02-7-000
MN Transmission Cost Recovery Rider Accrued Revenues	E017/M-21-811
MN Renewable Resource Rider Accrued Revenues	E017-M-22-577
MN Decoupling	E017-M-20-719
Conservation Improvement Program Costs & Incentives - MN	E017/M-20-475; EL017/CIP-23-150
Energy Efficiency Program - SD	EL23-012
SD Transmission Cost Recovery Rider Accrued Revenues	EL22-031
ND Renewable Resource Rider Accrued Revenues	PU-22-429
MISO Schedule 26 and 26A Trans Cost Recovery Rider True-up	E017/M-16-374
SPP Cost Recovery Rider	E017/M-16-374
MN Deferred Rate Case Expenses Subject to Recovery	E017/M-16-374
MN Fuel Clause Adjustment	E017/AA-21-311 E017/AA-22-214
ND Fuel Clause Adjustment	PU-17-398
SD Fuel Clause Adjustment	EL18-021

(b) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(d) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(e) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(f) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(g) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(h) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(i) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

(j) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Offsetting accounts used were 440, 442, 444, and 445

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Conservation Improvement					
2	Programs - MN		16,580,079	182.3	16,580,079	
3	Energy Efficiency Program - SD		1,085,287	182.3	1,085,287	
4	Deposits for Construction Related Activities		2,569,951	186.0	1,442,953	1,126,998
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL					1,126,998

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Insurance Reserve		
3	Workman's Compensation Reserve	225,189	206,348
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	122,011,804	105,498,577
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	122,236,993	105,704,925
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	122,236,993	105,704,925

Notes

Not Applicable

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

	BALANCE AT BEGIN OF YEAR	BALANCE AT END OF YEAR
Post Retirement Benefits	15,411,716	13,711,889
Executive Supplemental Pension	2,502,599	2,322,252
Reserve for Bad Debts	330,286	394,363
Performance Shares	221,977	246,872
Accrued Vacation Pay	1,178,892	1,251,608
Capitalized Int. on Construction	6,647,573	7,037,116
Post Employment Benefits	166,138	210,476
Bonus Incentive	667,964	1,401,458
Nonqualified Retirement Savings	421,890	472,441
Deferred Settlement	20,172	0
Capitalized A & G	624,385	512,927
Customer Rebates Capitalized	352,602	393,323
Asbestos Removal Costs Capitalized	37,359,597	32,992,884
Stock Incentives	71,317	111,062
Executive Restoration Plan	169,405	269,883
Unicap Adjustment	16,496	17,227
Medicare Part D	131,098	107,384
Flow-Through Items	(68,759)	(104,177)
State NOL Carryforward	169,921	0
Wind Energy Income Tax Credits-ND	32,424,769	28,390,374
ASC 740 Unamortized ITC	357,604	356,501
ASC 740 Recognition of Regulatory Assets (Liab.)	2,319,795	2,599,461
Excess Accumulated Deferred Tax due to Federal Rate Change	(2,173,514)	(1,894,230)
Wind Production Tax Credit Deferral (Asset)	22,687,881	14,697,483
	<u>122,011,804</u>	<u>105,498,577</u>

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2) <input type="checkbox"/> A Resubmission		

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock	50,000,000	5.00		100	500				
7	Total	50,000,000			100	500				
8	Preferred Stock (Account 204)									
9	Cumulative Preferred	1,500,000								
10	Cumulative Preference	1,000,000								
15	Total	2,500,000								
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 2023-12-31	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

- a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
- b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	636,988,966
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	40,000,000
16	Ending Balance Amount	676,988,966
17	Historical Data - Other Paid in Capital	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	676,988,966

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Shares	
2	Not applicable	
3	Cumulative Preferred Shares	
22	TOTAL	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)
1	Bonds (Account 221)										
2	Senior Unsecured Notes 6.37%, Series C	181	42,000,000		522,146			08/20/2007	08/20/2027	08/20/2007	08/20/2027
3	Senior Unsecured Notes 3.07%, Series A	181	10,000,000		52,446			10/10/2019	10/10/2029	10/10/2019	10/10/2029
4	Senior Unsecured Notes 4.68%, Series A	181	60,000,000		233,049			02/27/2014	02/27/2029	02/27/2014	02/27/2029
5	Senior Unsecured Notes 3.22%, Series A	181	10,000,000		49,855			02/25/2020	02/25/2030	02/25/2020	02/25/2030
6	Senior Unsecured Notes 3.22%, Series B	181	40,000,000		192,872			08/20/2020	08/20/2030	08/20/2020	08/20/2030
7	Senior Unsecured Notes 2.74%, Series A	181	40,000,000		188,991			11/29/2021	11/29/2031	11/29/2021	11/29/2031
8	Senior Unsecured Notes 6.47%, Series D	181	50,000,000		643,807			08/20/2007	08/20/2037	08/20/2007	08/20/2037
9	Senior Unsecured Notes 3.52%, Series B	181	26,000,000		136,360			10/10/2019	10/10/2039	10/10/2019	10/10/2039
10	Senior Unsecured Notes 3.62%, Series C	181	10,000,000		47,778			02/25/2020	02/25/2040	02/25/2020	02/25/2040
11	Senior Unsecured Notes 5.47%, Series B	181	90,000,000		347,548			02/27/2014	02/27/2044	02/27/2014	02/27/2044
12	Senior Unsecured Notes 4.07%, Series A	181	100,000,000		511,350			02/07/2018	02/07/2048	02/07/2018	02/07/2048
13	Senior Unsecured Notes 3.82%, Series C	181	64,000,000		335,655			10/10/2019	10/10/2049	10/10/2019	10/10/2049
14	Senior Unsecured Notes 3.92%, Series D	181	15,000,000		71,667			02/10/2020	02/10/2050	02/10/2020	02/10/2050
15	Senior Unsecured Notes 3.69%, Series B	181	100,000,000		464,405			11/29/2021	11/29/2051	11/29/2021	11/29/2051
16	Senior Unsecured Notes 3.77%, Series C	181	90,000,000		434,532			05/20/2022	05/31/2052	05/20/2022	05/31/2052
17	Subtotal		747,000,000		4,232,461						
18	Reacquired Bonds (Account 222)										
19											
20											
21											
22	Subtotal										
23	Advances from Associated Companies (Account 223)										
24											
25											
26											
27	Subtotal										
28	Other Long Term Debt (Account 224)										
29											
30											
31											
32	Subtotal										
33	TOTAL		747,000,000								

Line No.	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1		
2	42,000,000	2,675,400
3	10,000,000	243,000
4	60,000,000	2,808,000
5	10,000,000	322,000
6	40,000,000	1,032,000
7	40,000,000	1,096,000
8	50,000,000	3,235,000
9	26,000,000	915,200
10	10,000,000	362,000
11	90,000,000	4,923,000
12	100,000,000	4,070,000
13	64,000,000	2,444,800
14	15,000,000	588,000
15	100,000,000	3,690,000
16	90,000,000	3,393,000
17	747,000,000	31,797,400
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33	747,000,000	31,797,400
Page 256-257 Part 2 of 2		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	84,424,141
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	1,838,931
6	Net Gain from Property Retirements	(2,925,565)
7	Miscellaneous Taxable Items	3,000
8	Conservation Improvement Programs	352,444
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj.)	1,633,614
11	Provision for Reserves	(5,017,232)
12	Miscellaneous Unallowed Deductions	63,841,476
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	
16	Equity in Earnings of Subsidiaries	
17	Wind Rider Revenue	
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	75,443,887
21	Removal Costs	(12,056,832)
22	Charges to Reserves	7,182,756
23	Leveraged ESOP Deduction	1,234,586
24	Sec 481(a) Cap to Repair Basis Adjustments	
25	Miscellaneous Other Deductions	55,226,565
27	Federal Tax Net Income	17,119,846
28	Show Computation of Tax:	
29	Federal Tax (LINE 27 X 21%)	3,595,168
30	Tax (Credits) and Adjustments	(2,699,375)
31	Prior Period Adjustments	(21,115,362)
32	Transfer Net Operating Loss to Deferred Carryforward	
33	Total Federal Income Tax	(20,219,569)
34	Charged to Account 5410.1001	(20,740,034)
35	Charged to Account 5410.2001	520,465
36	Charged to Account 5410.4120	
37	Total	¹⁹ (20,219,569)

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: ComputationOfTax

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME
FOR FEDERAL INCOME TAXES (Continued)

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2023. The other members of the affiliated group and their respective federal income tax provisions are as follows:

Otter Tail Corporation	-1,423,763
Varistar Corporation	-3,514
BTD Manufacturing, Inc.	6,487,752
Northern Pipe Products, Inc.	20,787,939
Vinyltech Corporation	32,960,514
T. O. Plastics, Inc.	-243,311
Otter Tail Assurance Limited	163,745
Total	58,729,362

The consolidated federal income tax liability is allocated on a separate return basis pursuant to the current tax sharing agreements between Otter Tail Corporation and the subsidiaries.

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TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Include in Account 165) (k)
1		Income Tax			371,780		3,592,173	3,053,280		910,673	
2		Unemployment Tax			824		36,751	36,882		693	
3		Federal Insurance Tax					5,927,461	5,927,461			
4		Subtotal Federal Tax			372,604		9,556,385	9,017,623		911,366	
5		Property Tax	Minnesota		10,117,350		9,270,786	9,906,229		9,481,907	
6		Income Tax	Minnesota		1		838,645	2		838,644	
7		Unemployment Tax	Minnesota		9,636		31,525	(5,591)		46,752	
8		Property Tax	North Dakota		3,786,824		4,731,552	4,465,033		4,053,343	
9		Income Tax	North Dakota		2		292,886	292,886		2	
10		Unemployment Tax	North Dakota		717		18,630	18,417		930	
11		Other Taxes and Fees	North Dakota		26,053		106,689	107,219		25,523	
12		Property Tax	South Dakota		3,062,168		2,503,564	2,609,871		2,955,861	
13		Unemployment Tax	South Dakota		86		6,788	6,755		119	
14		Income Tax	Other								
15		Unemployment Tax	Other		(585)		1,200	986		(371)	
16		Other Taxes and Fees	Other		148		1,179	1,092		235	
17		Subtotal State Tax			17,002,400		17,803,444	17,402,899		17,402,945	
40		TOTAL			17,375,004		27,359,829	26,420,522		18,314,311	

DISTRIBUTION OF TAXES CHARGED

Line No.	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	(20,740,035)			24,332,208
2				36,751
3				5,927,461
4	(20,740,035)			30,296,420
5	9,270,780			6
6	724,472			114,173
7				31,525
8	4,723,704			7,848
9	(3,567,226)			3,860,112
10				18,630
11	106,689			
12	2,503,564			
13				6,788
14				
15				1,200
16				1,179
17	13,761,983			4,041,461
40	(6,978,052)			34,337,881

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: TaxesIncurredOther Account 409.2: 520,465 Other 23,811,743
(b) Concept: TaxesIncurredOther Account 184: 36,751
(c) Concept: TaxesIncurredOther Account 184: 5,927,461
(d) Concept: TaxesIncurredOther Account 409.2: 129,141 Other (14,968)
(e) Concept: TaxesIncurredOther Account 184: 31,525
(f) Concept: TaxesIncurredOther Account 408.2: 7,848
(g) Concept: TaxesIncurredOther Account 409.2: 44,200 Other 3,815,912
(h) Concept: TaxesIncurredOther Account 184: 18,630
(i) Concept: TaxesIncurredOther Account 184: 6,788
(j) Concept: TaxesIncurredOther Account 184: 1,200
(k) Concept: TaxesIncurredOther Account 151: 1,179

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2) <input type="checkbox"/> A Resubmission		

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%	15,828,366	190.0		411.4	741,833		15,086,533	35 years	
3	4%								—	
4	7%								—	
5	10%		411.4		411.4				—	
6	30%	87,742	190.0		411.4	2,685		85,057	35 years	
7									—	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	15,916,108				744,518		15,171,590		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10									—	
47	OTHER TOTAL									
48	GRAND TOTAL	15,916,108						15,171,590		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Prepaid Electric Revenue	1,798,376	456	826,394	848,058	1,820,040
2	Asset Reclass	617,016	184	426,300		190,716
3	ASC 842 Leases	148,455	173		8,851	157,306
4	Deferred Revenue	84,998	456	747,622	719,634	57,010
47	TOTAL	2,648,845		2,000,316	1,576,543	2,225,072

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities								0		
4	Pollution Control Facilities	10,629,721	(173,089)						254	45,116	10,501,748
5	Other										
5.1						0			0		
5.2	Other (provide details in footnote):								0		
8	TOTAL Electric (Enter Total of lines 3 thru 7)	10,629,721	(173,089)							45,116	10,501,748
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1						0			0		
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	10,629,721	(173,089)							45,116	10,501,748
18	Classification of TOTAL										
19	Federal Income Tax	7,825,758	(134,449)				0		0	45,116	7,736,425
20	State Income Tax	2,803,963	(38,640)				0		0		2,765,323
21	Local Income Tax						0		0		

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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	279,386,187	29,969,037	10,616,220		6,404	254		182.3	(5,895,195)	292,837,405
3	Gas						0		0		
4	Other (Specify)						0		0		
5	Total (Total of lines 2 thru 4)	279,386,187	29,969,037	10,616,220		6,404				(5,895,195)	292,837,405
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	279,386,187	29,969,037	10,616,220		6,404				(5,895,195)	292,837,405
10	Classification of TOTAL										
11	Federal Income Tax	211,066,012	22,597,059	7,587,478		4,851				(4,945,479)	221,125,263
12	State Income Tax	68,320,175	7,371,978	3,028,742		1,553				(949,716)	71,712,142
13	Local Income Tax										

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Amort of Loss on Reacquired Debt (pre holdco)	53,208
Deferred HLP Cost Recovery	(323,742)
South Dakota Flow Thru-Overheads	(53,076)
Prepaid Expenses	1,191,222
ADR Repair Allowance	1,253,400
Sec 162 & 174 R&D Deduction	1,879,304
Highway Reimbursements	817,042
AFUDC on Debt	4,366,676
Capitalized Overheads	(1,097,678)
Repairs Deduction - Basis Adjustments	3,882,401
Sec 481(a) Cap to Repair Basis Adjustments (PY)	(4,188,887)
Excess Tax over book Depreciation	313,155,336
North Dakota Investment Tax Credit - Federal Impacts	5,296,660
Excess Accumulated Deferred Tax due to Federal Rate Change	(34,076,015)
ASC 740 (SFAS 109) ADIT Credits - Property	681,554
	<hr/>
	292,837,405

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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	<input type="checkbox"/> A Resubmission		

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Other Utility Operations	24,225,692	(13,861,844)	(11,513,744)	(503)	(393)			See Note	233,071	22,110,553
4	Nonutility & Other	3,336,911			669,453	761,152					3,245,212
9	TOTAL Electric (Total of lines 3 thru 8)	27,562,603	(13,861,844)	(11,513,744)	668,950	760,759				233,071	25,355,765
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	27,562,603	(13,861,844)	(11,513,744)	668,950	760,759				233,071	25,355,765
20	Classification of TOTAL										
21	Federal Income Tax	18,153,061	(10,486,421)	(8,693,536)	505,880	575,154				202,178	16,493,080
22	State Income Tax	9,409,542	(3,375,423)	(2,820,208)	163,070	185,605				30,893	8,862,685
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Deferred taxes related to CIP costs

(b) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherDescriptionOfCreditedAccountNumber

Adjustment related to ASC 740 and excess accumulated deferred tax due to federal rate change

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Pensions	-25,264,479
Conservation Improvement Program - MN & SD - Net (BTL)	-3,245,068
Rate Rider Mechanism	4,019,808
ND Rate Case Expenses	-118,290
MN Rate Case Expenses	-199,876
SD Rate Case Expenses	1
Regulatory Adjustments - JE 820 ESSRP	414,089
Excess Accumulated Deferred Tax due to Federal Rate Change	618,528
ASC 740 (SFAS 109) ADIT Credits - Non-Property	-1,580,478
	-25,355,765

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Deferred Income Taxes:					
2	ASC 740	446,583	190	7,960,993	7,870,911	356,501
3	ADIT Legacy Reclass	131,033,625	See Note 1	3,650,736	8,282,950	135,665,839
4	Post-retirement Benefit Plans:					
5	Post Retirement Medical Benefits	5,589,435	254	7,529,382	19,025,921	17,085,974
6	Fuel Clause Adjustment:					
7	MN Refundable Fuel Clause Adj Revenue		See Note 2	2,933,663	14,216,839	11,283,176
8	ND Refundable Fuel Clause Adj Revenues	365,455	See Note 2	17,177,615	16,812,160	
9	SD Refundable Fuel Clause Adjustment Revenues		See Note 2	896,705	963,376	66,671
10	Alternative Revenue Program Riders:					
11	ND Transmission Cost Recovery Rider Accrued Refund	246,578	See Note 2	247,981	995,805	994,402
12	SD Transmission Cost Recovery Rider Accrued Refund	145,107	See Note 2	161,354	16,247	
13	ND Renewable Resource Rider Accrued Revenues	7,748,398	See Note 2	698,938	4,961,242	12,010,702
14	SD Phase-in Rider	36,000	See Note 2	333,226	473,849	176,623
15	ND Generation Cost Recovery Rider	933,003	See Note 2	829,901	82,201	185,303
16	MN Transmission Cost Recovery Rider Accrued Refund		See Note 2	97,571	1,347,277	1,249,706
17	MN EITE Cost Recovery Rider	143,067	See Note 2	303,688	205,799	45,178
18	SD Phase-in for AMI	103,827	See Note 2	370	225,744	329,201
19	MN Decoupling	254,814	See Note 2	403,413	925,482	776,883
20	MN Uplift Program Rider	184,192			441,696	625,888
21	MN EUIC Rider for AMI	171,807			249,037	420,844
22	ND AMDT Rider				2,132,708	2,132,708
23	Conservation Improvement Program Costs & Incentives - MN		407.4	2,710,782	3,329,680	618,898
24	ISO Cost Recovery Trackers:					
25	MISO Schedule 26 and 26A Accrual	14,843	407.4	581,585	926,056	359,314
26	Other:					
27	MN portion of gain on sale of Wahpeton	61,339	407.4	5,576		55,763
28	MN Credit Card Fees Tracker	77,722	See Note 3	15,285	65,171	127,608
29	See Footnote in Notes to Financial					
30	Statements for amortization periods.					
41	TOTAL	147,555,795		46,538,764	83,550,151	184,567,182

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Regulatory Liability Description	Docket
ADIT Legacy Reclass	PU-17-398; EL18-021; E.G-999/CI-17-895
Post Retirement Medical Benefits Actuarial Adjustment	PU-17-398
MN Refundable Fuel Clause Adjustment Revenues	E017/AA-22-214
ND Refundable Fuel Clause Adjustment Revenues	PU-17-398
SD Refundable Fuel Clause Adjustment Revenues	EL18-021
ND Transmission Cost Recovery Rider Accrued Refund	PU-23-306
SD Transmission Cost Recovery Rider Accrued Refund	EL22-031
ND Renewable Resource Rider Accrued Revenues	PU-22-429
SD Phase-in Rider	EL23-015
ND Generation Cost Recovery Rider	PU-23-083
MN Transmission Cost Recovery Rider Accrued Refund	E017/M-21-811
MN EITE Cost Recovery Rider	E017-M-23-162
SD Phase-in for AMI	EL23-015
MN Decoupling	E017/GR-20-719
MN Uplift Program Rider	E017-M-22-133
MN EUIC Rider for AMI	E017/M-21-382
ND AMDT Rider	PU-23-283
Conservation Improvement Program Costs & Incentives - MN	E017/M-20-475; EL017/CIP-23-150
MISO Schedule 26 and 26A Trans Cost Recover Rider True-up	E017/M-16-374
MN Credit Card Fees Tracker	E017/GR-20-719

(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 182.3, 282, 283, and 190

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(e) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(f) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(g) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(h) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(i) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(j) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(k) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(l) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(m) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, and 445.

(n) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 182.3, 440, 442, 444, and 445.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

Electric Operating Revenues

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	135,000,005	143,944,888	1,254,809	1,309,247	105,555	104,894
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	92,482,286	100,593,238	982,756	1,009,145	27,141	27,059
5	Large (or Ind.) (See Instr. 4)	217,745,016	218,147,823	3,477,561	3,215,048	843	845
6	(444) Public Street and Highway Lighting	3,921,745	4,130,806	14,427	15,283	655	656
7	(445) Other Sales to Public Authorities	3,766,451	3,789,097	42,662	43,645	1,241	1,247
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	452,915,503	470,605,852	5,772,215	5,592,368	135,435	134,701
11	(447) Sales for Resale	12,459,056	18,538,975	371,113	277,830		
12	TOTAL Sales of Electricity	465,374,559	489,144,827	6,143,328	5,870,198	135,435	134,701
13	(Less) (449.1) Provision for Rate Refunds		2,788,067				
14	TOTAL Revenues Before Prov. for Refunds	465,374,559	486,356,760	6,143,328	5,870,198	135,435	134,701
15	Other Operating Revenues						
16	(450) Forfeited Discounts	871,329	800,374				
17	(451) Miscellaneous Service Revenues	352,447	364,482				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	1,189,518	945,169				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	4,461,012	5,500,001				
22	(456.1) Revenues from Transmission of Electricity of Others	51,865,486	51,507,712				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	58,739,792	59,117,738				
27	TOTAL Electric Operating Revenues	524,114,351	545,474,498				

Line12, column (b) includes \$ 1,500,981 of unbilled revenues.

Line12, column (d) includes 43,710 MWH relating to unbilled revenues

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: MiscellaneousServiceRevenues		
<u>Description of Revenue</u>	<u>Q4 2023</u>	<u>Q4 2022</u>
All others (under \$250,000 each)	352,447	364,482
Total	352,447	364,482
(b) Concept: OtherElectricRevenue		
<u>Description of Revenue</u>	<u>Q4 2023</u>	<u>Q4 2022</u>
Sale of steam	1,129,715	3,645,657
Load Control & Dispatch	1,567,355	1,587,594
Renewable Energy RECs Generated	821,797	—
All others (under \$250,000 each)	942,145	266,750
Total	4,461,012	5,500,001

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable				
46	TOTAL				

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential - 440					
2	9.01 Residential Service	925,444	114,066,280	105,555	8,767	0.1233
3	9.02 Residential Service-Controlled Demand	128,041	13,593,123	4,303	29,756	0.1062
4	11.03 Outdoor Lighting - Energy Only	105	9,581	19		0.0900
5	11.04 Outdoor Lighting	1,453	249,790	1,254	1,159	0.1700
6	11.07 LED Street and Area Lighting	623	336,648	1,834		0.5400
7	12.01 Small Power Producer Rider		1,018	40		
8	14.01 Water Heating - Controlled Service (Off-Peak)	30,995	3,253,553	11,473		0.1050
9	14.04 Controlled Service - Interruptible Load	268	17,014	8	33,525	0.0634
10	14.05 Controlled Service - Interruptible Load	165,704	11,228,100	9,144		0.0678
11	14.06 Controlled Service - Deferred Load	12,377	1,124,400	822	15,057	0.0908
12	14.07 Fixed Time of Delivery Service	5,971	387,540	352		0.0649
13	14.08 Air Conditioning Control Rider		(72,955)	562		
14	14.09 Voluntary Renewable Energy Rider		23,349	171		
15	14.12 Off-Peak Electric Vehicle Rider	84	7,709	15	5,610	0.0916
16	Other	(1)	(9,235)	(29,997)		9.3645
41	TOTAL Billed Residential Sales	1,271,064	144,215,915	105,555	12,042	0.1135
42	TOTAL Unbilled Rev. (See Instr. 6)	(16,255)	(9,215,910)			0.5670
43	TOTAL	1,254,809	135,000,005	105,555	11,888	0.1076

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: AverageNumberOfCustomersPerMonthResidentialSalesBilled

Average number of customers are included within the Residential Service categories listed.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial & Industrial (Small) - 442					
2	Commercial (Small)					
3	9.01 Residential Service	933	104,249	49	2,128	0.1117
4	9.02 Residential Service-Controlled Demand	1,000	98,127	25		0.0981
5	9.03 Farm Service	74,768	8,178,303	2,726	3,000	0.1094
6	10.01 General Service	216,149	27,494,115	19,796		0.1272
7	10.02 General Service	530,683	57,313,251	4,619	12,408	0.1080
8	10.03 Commercial Time-of-Use	3,914	416,550	16		0.1064
9	10.07 EV DCFC General Service - Time of Day	104	11,989	2	5,994	0.1153
10	11.02 Irrigation Service	9,055	880,655	127		0.0973
11	11.03 Outdoor Lighting - Energy Only	1,984	198,236	244		0.0999
12	11.04 Outdoor Lighting	4,440	709,700	1,377	515	0.1599
13	11.05 Municipal Pumping Service	(6)	(479)			0.0810
14	11.06 Fire Sirens		708	8	88	
15	11.07 LED Street and Area Lighting	3,123	1,342,161	2,035	660	0.4298
16	12.01 Small Power Producer Rider		1,395	33		
17	12.02 Small Power Producer Rider		1			
18	14.01 Water Heating - Controlled Service (Off-Peak)	1,572	130,505	358		0.0830
19	14.04 Controlled Service - Interruptible Load	53,085	2,890,107	272	10,625	0.0544
20	14.05 Controlled Service - Interruptible Load	59,566	3,591,940	2,056	1,747	0.0603
21	14.06 Controlled Service - Deferred Load	20,327	1,417,006	479	2,958	0.0697
22	14.07 Fixed Time of Delivery Service	24,784	1,419,225	436		0.0573
23	14.08 Air Conditioning Control Rider		(14,835)	25	(593)	
24	14.09 Voluntary Renewable Energy Rider		8,872	20		
25	14.1 WAPA Bill Crediting Program Rider			26		
26	14.12 Off-Peak Electric Vehicle Rider	39	3,489	1		0.0896
27	Other	(96)	(34,084)	(7,589)	4	0.3545
41	TOTAL Billed Small or Commercial	1,005,424	106,161,186	27,141	37,044	0.1056
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(22,668)	(13,678,900)			0.6034
43	TOTAL Small or Commercial	982,756	92,482,286	27,141	36,209	0.0941

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

[\(a\)](#) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercialBilled
Average number of customers are included within the Commercial (Small) Service categories listed.
FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial & Industrial (Large) - 442					
2	Commercial (Large)					
3	10.01 General Service	4,198	421,553	74	5,697	0.1004
4	10.02 General Service	31,848	3,422,361	62	55,199	0.1075
5	10.03 Commercial Time-of-Use	14,777	1,414,543	11	128,595	0.0957
6	10.04 Large General Service	1,056,188	89,482,716	842	106,274	0.0847
7	10.05 Large General Service - Time of Day	1,163,609	83,111,106	26	3,196,581	0.0714
8	10.06 Super Large General Service	764,575	28,795,267	1	28,795,267	0.0377
9	11.01 Standby Service - Option A Firm	144	17,273			0.1202
10	11.03 Outdoor Lighting - Energy Only	51	5,007	14	358	0.0973
11	11.04 Outdoor Lighting	273	43,830	49	894	0.1603
12	11.07 LED Street and Area Lighting	266	87,703	118	743	0.3301
13	12.01 Small Power Producer Rider		86	3	29	
14	12.02 Small Power Producer Rider		8			
15	12.03 Small Power Producer Rider		15			
16	14.01 Water Heating - Controlled (Off-Peak)	101	5,929	3	1,976	0.0586
17	14.02 Real Time Pricing Rider	70,911	3,398,790	2	1,699,395	0.0479
18	14.03 Large General Service Rider	317,390	14,360,513	8	1,795,064	0.0452
19	14.04 Controlled Service - Interruptible Load	49,654	2,554,438	49	52,131	0.0514
20	14.05 Controlled Service - Interruptible Load	2,294	114,029	18	6,335	0.0497
21	14.06 Controlled Service - Deferred Load	3,586	212,295	8	26,537	0.0592
22	14.07 Fixed Time of Delivery Service	2,366	121,113	14	8,651	0.0512
23	14.08 Air Conditioning Control Rider		(6,293)			
24	14.09 Voluntary Renewable Energy Rider		20,988	4	5,247	
25	14.1 WAPA Bill Crediting Program Rider					
26	Other	(96)	(34,084)	463	74	0.3545
41	TOTAL Billed Large (or Ind.) Sales	3,482,135	227,549,186	843	4,130,647	0.0653
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(4,574)	(9,804,170)			2.1435
43	TOTAL Large (or Ind.)	3,477,561	217,745,016	843	4,125,221	0.0626

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
Average number of customers are included within the Commercial (Large) Service categories listed.
FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Streetlighting - 444					
2	11.03 Outdoor Lighting - Energy Only	4,760	430,792	238	1,810	0.0905
3	11.04 Outdoor Lighting	5,220	994,575	158	6,295	0.1905
4	11.07 LED Street and Area Lighting	4,449	2,553,715	259	9,860	0.5740
5	Adjustment		48			2,378.5000
41	TOTAL Billed Public Street and Highway Lighting	14,429	3,979,130	655	22,029	0.2758
42	TOTAL Unbilled Rev. (See Instr. 6)	(2)	(57,385)			0.1749
43	TOTAL	14,427	3,921,745	655	22,026	0.2718

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Other Public Authority-445					
2	10.01 General Service	113	16,336	15	7,539	0.1445
3	10.02 General Service	256	34,473	3		0.1348
4	11.03 Outdoor Lighting - Energy Only	40	3,853	5	771	0.0957
5	11.04 Outdoor Lighting	12	2,266	5		0.1825
6	11.05 Municipal Pumping Service	41,573	3,850,862	1,095	3,517	0.0926
7	11.06 Fire Sirens		10,685	96		
8	11.07 LED Street and Area Lighting	3	2,149	5	430	0.6248
9	14.04 Controlled Service - Interruptible Load	516	24,017	4	6,004	0.0465
10	14.05 Controlled Service - Interruptible Load	269	15,036	9		0.0559
11	14.06 Controlled Service - Deferred Load	63	5,027	1	5,027	0.0798
12	14.07 Fixed Time of Delivery Service	28	1,820	3		0.0656
13	Other		3,438			(3,438.0700)
41	TOTAL Billed Other Sales to Public Authorities	42,873	3,969,962	1,241	34,547	0.0926
42	TOTAL Unbilled Rev. (See Instr. 6)	(211)	(203,511)			(0.1314)
43	TOTAL	42,662	3,766,451	1,241	34,377	0.0883

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Revenue from Fuel Adjustment					
2	Clause is reported in footnote.					
3	Provision for Rate Refunds					
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

The following revenue received through the fuel clause adjustment is included in the amounts reported on pages 304-304.3.

Residential - 440			
1 Residential	9.01 Residential Service		\$23,040,082
1 Residential	9.02 Residential Demand Control Service		\$3,419,260
1 Residential	10.01 Small General Service Under 20 kW		\$120
1 Residential	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn		\$1,856
1 Residential	11.04 Outdoor Lighting - Dusk to Dawn		\$27,178
1 Residential	11.07 LED Street and Area Lighting		\$12,316
1 Residential	14.01 Water Heating Control Rider		\$750,402
1 Residential	14.04 Controlled Service - Interruptible Load - CT Metering Rider		\$6,157
1 Residential	14.05 Controlled Service - Interruptible Load - Self-Contained Metering Rider		\$4,646,393
1 Residential	14.06 Controlled Service - Deferred Load Rider		\$329,802
1 Residential	14.07 Fixed Time of Service Rider		\$160,439
1 Residential	14.12 Off-Peak Electric Vehicle Rider		\$1,955
	Total Residential		\$32,395,959
Commercial and industrial - 442			
2 Commercial	9.01 Residential Service		\$23,577
2 Commercial	9.02 Residential Demand Control Service		\$26,545
2 Commercial	9.03 Farm Service		\$1,729,321
2 Commercial	10.01 Small General Service Under 20 kW		\$5,428,189
2 Commercial	10.02 General Service 20 kW or Greater		\$13,364,824
2 Commercial	10.03 General Service - Time Of Use		\$504,760
2 Commercial	10.04 Large General Service		\$23,544,022
2 Commercial	10.05 Large General Service - Time Of Day		\$28,744,910
2 Commercial	10.06 Super Large General Service		\$14,715,322
2 Commercial	10.07 EV DCFC General Service - Time of Day		\$2,743
2 Commercial	11.01 Standby Service		\$2,293
2 Commercial	11.02 Irrigation Service		\$173,275
2 Commercial	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn		\$38,140
2 Commercial	11.04 Outdoor Lighting - Dusk to Dawn		\$83,323
2 Commercial	11.05 Municipal Pumping Service		-\$220
2 Commercial	11.07 LED Street and Area Lighting		\$65,506
2 Commercial	14.01 Water Heating Control Rider		\$41,557
2 Commercial	14.03 Large General Service Rider		\$7,956,005
2 Commercial	14.04 Controlled Service - Interruptible Load - CT Metering Rider		\$2,800,955
2 Commercial	14.05 Controlled Service - Interruptible Load - Self-Contained Metering Rider		\$1,757,941
2 Commercial	14.06 Controlled Service - Deferred Load Rider		\$642,014
2 Commercial	14.07 Fixed Time of Service Rider		\$731,435
2 Commercial	14.12 Off-Peak Electric Vehicle Rider		\$963
	Total Commercial and industrial		\$102,377,398
Streetlighting			
4 Streetlighting	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn		\$84,561
4 Streetlighting	11.04 Outdoor Lighting - Dusk to Dawn		\$94,995
4 Streetlighting	11.07 LED Street and Area Lighting		\$87,539
	Total Streetlighting		\$267,095
Other public authority - 445			
5 OPA	10.01 Small General Service Under 20 kW		\$2,827
5 OPA	10.02 General Service 20 kW or Greater		\$6,381
5 OPA	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn		\$664
5 OPA	11.04 Outdoor Lighting - Dusk to Dawn		\$193
5 OPA	11.05 Municipal Pumping Service		\$1,001,839
5 OPA	11.07 LED Street and Area Lighting		\$69
5 OPA	14.04 Controlled Service - Interruptible Load - CT Metering Rider		\$11,387
5 OPA	14.05 Controlled Service - Interruptible Load - Self-Contained Metering Rider		\$6,042
5 OPA	14.06 Controlled Service - Deferred Load Rider		\$1,633
5 OPA	14.07 Fixed Time of Service Rider		\$727
	Total Other public authority		\$1,031,762
	TOTAL Billed FCA Revenue		\$136,072,214

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	5,815,925	485,875,379	135,435	42,943	0.0835
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(43,710)	(32,959,876)			0.7541
43	TOTAL - All Accounts	5,772,215	452,915,503	135,435	42,620	0.0785

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

SALES FOR RESALE (Account 447)

- Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
- Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 - RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 - LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
 - IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 - SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 - LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 - IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.
 - OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
 - AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
- Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
- In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
- For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
- The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	RQ SALES										
2	Badger, SD	RQ	144	0.24			313	13,996	10,574	3,995	28,565
3	Newfolden, MN	RQ	174	0.36			1,926	18,519	66,858	16,950	102,327
4	Nielsville, MN	RQ	175	0.01			70	433	2,380	627	3,440
5	Shelly, MN	RQ	176	0.21			692	14,917	23,567	7,518	46,002
6	NON-RQ SALES										
7	Midwest ISO Energy Market	OS	v9				368,112		12,278,722		12,278,722
15	Subtotal - RQ						3,001	47,865	103,379	29,090	180,334
16	Subtotal-Non-RQ						368,112		12,278,722		12,278,722
17	Total						371,113	47,865	12,382,101	29,090	12,459,056

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges
(b) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges
(c) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges
(d) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2) <input type="checkbox"/> A Resubmission		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,318,672	1,446,943
5	(501) Fuel	43,998,317	44,772,884
6	(502) Steam Expenses	4,660,979	5,654,992
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,650,981	1,776,145
10	(506) Miscellaneous Steam Power Expenses	3,844,208	4,471,713
11	(507) Rents	5,006	(5,533)
12	(509) Allowances		181
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	55,478,163	58,117,325
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	551,458	624,662
16	(511) Maintenance of Structures	769,295	795,762
17	(512) Maintenance of Boiler Plant	5,798,533	6,980,241
18	(513) Maintenance of Electric Plant	1,460,691	2,866,936
19	(514) Maintenance of Miscellaneous Steam Plant	1,103,508	941,350
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,683,485	12,208,951
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	65,161,648	70,326,276
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	15,009	51,177
45	(536) Water for Power		
46	(537) Hydraulic Expenses	3,266	8,156
47	(538) Electric Expenses	154	860
48	(539) Miscellaneous Hydraulic Power Generation Expenses	22,558	35,808

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	40,987	96,001
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	6,999	345
54	(542) Maintenance of Structures	3,353	26,644
55	(543) Maintenance of Reservoirs, Dams, and Waterways	232,540	265,138
56	(544) Maintenance of Electric Plant	8,209	18,437
57	(545) Maintenance of Miscellaneous Hydraulic Plant	23,304	718
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	274,405	311,282
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	315,392	407,283
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	324,560	498,816
63	(547) Fuel	16,592,984	20,578,473
64	(548) Generation Expenses	3,501,089	2,650,988
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	3,501,451	2,211,236
66	(550) Rents	1,833,638	1,451,522
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	25,753,722	27,391,035
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	23,925	25,834
70	(552) Maintenance of Structures	49,766	77,501
71	(553) Maintenance of Generating and Electric Plant	5,252,733	4,736,562
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	811,540	392,863
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	6,137,964	5,232,760
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	31,891,686	32,623,795
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	78,291,775	100,281,054
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	436,672	431,659
78	(557) Other Expenses	45,083	42,138
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	78,773,530	100,754,851
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	176,142,256	204,112,205
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	161,483	249,664
85	(561.1) Load Dispatch-Reliability	70,936	84,388
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,144,552	2,441,069
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,051,162	1,211,833
89	(561.5) Reliability, Planning and Standards Development	418,245	531,719
90	(561.6) Transmission Service Studies	13,789	80,983
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	413,014	395,015
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	294,619	783,176
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	24,751,740	23,764,287
97	(566) Miscellaneous Transmission Expenses	612,718	2,174,930
98	(567) Rents	72,876	37,445
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	30,005,134	31,754,509
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
101	(568) Maintenance Supervision and Engineering	260,881	288,580
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	98,822	18,138
104	(569.2) Maintenance of Computer Software	886,216	825,411
105	(569.3) Maintenance of Communication Equipment	65,937	63,034
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,237,569	1,471,875
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	2,786,293	2,019,929
109	(572) Maintenance of Underground Lines	576	1,133
110	(573) Maintenance of Miscellaneous Transmission Plant	425,508	
111	TOTAL Maintenance (Total of Lines 101 thru 110)	5,761,802	4,688,100
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	35,766,936	36,442,609
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	741,632	770,030
117	(575.3) Transmission Rights Market Facilitation	6,821	5,083
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	21,559	25,025
120	(575.6) Market Monitoring and Compliance	1,490	228
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	771,502	800,366
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	246,956	247,043
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	246,956	247,043
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	1,018,458	1,047,409
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	346,927	314,772
135	(581) Load Dispatching	85,201	281,414
136	(582) Station Expenses	349,208	332,859
137	(583) Overhead Line Expenses	240,219	232,250
138	(584) Underground Line Expenses	1,683,904	1,806,839
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	1,193	611
140	(586) Meter Expenses	991,468	888,210
141	(587) Customer Installations Expenses	3,163	7,532
142	(588) Miscellaneous Expenses	4,523,753	3,701,612
143	(589) Rents	205,605	194,724
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	8,430,641	7,760,823
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,084,783	627,121
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	704,515	598,486
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	7,625,101	6,068,194
150	(594) Maintenance of Underground Lines	786,820	811,407
151	(595) Maintenance of Line Transformers	171,171	184,714
152	(596) Maintenance of Street Lighting and Signal Systems	134,781	166,109

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
153	(597) Maintenance of Meters	1,063,452	950,342
154	(598) Maintenance of Miscellaneous Distribution Plant	134,777	136,501
155	TOTAL Maintenance (Total of Lines 146 thru 154)	11,705,400	9,542,874
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	20,136,041	17,303,697
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	30,045	31,226
160	(902) Meter Reading Expenses	6,063,885	6,048,973
161	(903) Customer Records and Collection Expenses	6,249,715	6,398,080
162	(904) Uncollectible Accounts	1,307,083	696,382
163	(905) Miscellaneous Customer Accounts Expenses	1,017,563	850,853
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	14,668,291	14,025,514
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	724,242	745,699
168	(908) Customer Assistance Expenses	10,010,491	9,890,948
169	(909) Informational and Instructional Expenses	145,028	98,070
170	(910) Miscellaneous Customer Service and Informational Expenses	91,766	131,916
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	10,971,527	10,866,633
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	9,034	14,113
175	(912) Demonstrating and Selling Expenses	426,603	572,597
176	(913) Advertising Expenses	1,196	252
177	(916) Miscellaneous Sales Expenses	5,444	5,738
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	442,277	592,700
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	29,701,057	28,959,962
182	(921) Office Supplies and Expenses	11,685,648	13,152,813
183	(Less) (922) Administrative Expenses Transferred-Credit	2,531,974	2,667,481
184	(923) Outside Services Employed	2,935,383	1,899,948
185	(924) Property Insurance	3,450,645	2,411,400
186	(925) Injuries and Damages	3,262,606	2,758,678
187	(926) Employee Pensions and Benefits	1,098,364	1,257,829
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,346,607	2,824,155
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	735,055	985,974
192	(930.2) Miscellaneous General Expenses	1,308,371	1,290,658
193	(931) Rents	344,035	330,177
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	54,335,797	53,204,113
195	Maintenance		
196	(935) Maintenance of General Plant	2,613,437	4,405,340
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	56,949,234	57,609,453
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	316,095,020	342,000,220

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
\$560,184 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.
(b) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
\$595,728 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnhtly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)
1	Rainbow Energy Marketing Corp	SF					57,600			
2	Manitoba Hydro	SF					117,800			
3	DTE Energy	SF					65,600			
4	Minnkota Power Cooperative	SF					37,200			
5	Western Area Power Administration	EX					(837)			
6	Western Area Power Administration - WEC	OS					28,534			
7	Beltrami Electric Cooperative	RQ					108,911			
8	Nodak Rural Electric Cooperative	RQ					5,496			
9	PKM Electric Cooperative	RQ					5,875			
10	Red Lake Rural Electric Cooperative	RQ					6,105			
11	Cass County Electric Cooperative	OS					49			
12	Whetstone Valley Electric Cooperative	OS								
13	City of Detroit Lakes	OS					848			
14	Kindred School	RQ					0			
15	Minnesota Power	SF					16,800			
16	Stevens Community Medical	RQ					0			
17	SLB Milbank, LLC	RQ					0			
18	American Crystal Sugar	OS					50			
19	Hendricks Wind I	RQ					1,027			
20	Borderline Wind	RQ					1,592			
21	University of MN - Morris	RQ					1,135			
22	Lac Qui Parle Valley High School	RQ					2			
23	Lake Region State College	RQ					3,270			
24	conEdison Development RLF Community Hybrid, LLC	RQ					13,969			
25	FPL Energy ND Wind II, LLC	RQ					56,682			
26	Langdon Wind, LLC	RQ					59,971			
27	Langdon Wind, LLC - Curtailment	RQ					2,772			
28	Ashtabula Wind III LLC	RQ					(1,474)			
29	Ashtabula Wind III LLC - Curtailment	RQ					(1,712)			
30	MN Co Generation	OS					820			
31	ND Co Generation	OS					110			
32	SD Co Generation	OS					22			
33	Midwest ISO Energy Market	OS					2,199,321			
34	Southwest Power Pool ISO Energy Market	OS					151			
15	TOTAL						2,787,689	0	0	0

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
1		2,784,149		2,784,149
2		6,421,029		6,421,029
3		3,497,156		3,497,156
4		2,416,809		2,416,809
5		(37,072)		(37,072)
6		785,601		785,601
7	2,043,221	5,365,510	78,542	7,487,273
8	108,698	270,284		378,982
9	134,311	364,681		498,992
10	132,644	328,593		461,237
11	1,988	10,262		12,250
12	1,034			1,034
13	1,122	1,280		2,402
14	50,000			50,000
15		1,344,000		1,344,000
16	27,840			27,840
17	64,350			64,350
18		502		502
19		50,512		50,512
20		47,760		47,760
21		59,585		59,585
22		132		132
23		102,903		102,903
24		489,184		489,184
25		1,694,794		1,694,794
26		2,350,124		2,350,124
27		108,728		108,728
28		(46,608)		(46,608)
29		(54,158)		(54,158)
30		81,290		81,290
31		4,963		4,963
32		951		951
33		46,281,858		46,281,858
34		923,223		923,223
15	2,565,208	75,648,025	78,542	78,291,775

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: OtherChargesOfPurchasedPower

Nomination charge

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (l) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY	
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)
1	Badger, SD	Western Area Power Administration	Badger, SD	LFP	4	(1)	Badger, SD		1,455	1,455
2	Newfolden, MN	Western Area Power Administration	Newfolden, MN	LFP	4	(1)	Newfolden, MN		2,775	2,775
3	Nielsville, MN	Western Area Power Administration	Nielsville, MN	LFP	4	(1)	Nielsville, MN		608	608
4	Shelly, MN	Western Area Power Administration	Shelly, MN	LFP	4	(1)	Shelly, MN		1,572	1,572
5	Fort Totten Indian Agency	Western Area Power Administration	Fort Totten, ND	LFP	4	(1)	Fort Totten, ND		309	309
6	State Development Center	Western Area Power Administration	Grafton, ND	LFP	4	(1)	Grafton, ND		4,636	4,636
7	North Dakota School for Deaf	Western Area Power Administration	Devils Lake, ND	LFP	4	(1)	Devils Lake, ND		444	444
8	North Dakota School of Forestry	Western Area Power Administration	Bottineau, ND	LFP	4	(1)	Bottineau, ND		1,116	1,116
9	North Dakota College of Science	Western Area Power Administration	Wahpeton, ND	LFP	4	(1)	Wahpeton, ND		7,896	7,896
10	Turtle Mountain Indian Agency	Western Area Power Administration	Belcourt, ND	LFP	4	(1)	Belcourt, ND		2,218	2,218
11	Oakes O&M Headquarters	Western Area Power Administration	Oakes, ND	LFP	4	(1)	Oakes, ND		62	62
12	Minnkota Power Cooperative, Inc.	Minnkota Power Cooperative, Inc.	Various Interconnects	OS	See Footnote ⁽²⁾	(1)	Various Interconnects		223,885	209,238
13		U.S. Bureau of Reclamation	Otter Tail Power Company	OS	—	—	(1)		862	
14		Various Companies	Otter Tail Power Company	OS	—	—	(1)		(275,511)	
15		⁽³⁾ Various Companies	Otter Tail Power Company	OS	—	—	(1)		(862)	
16		⁽³⁾ Various Companies	Various Companies	OS			Various Interconnects			
17	Midwest Independent System Operator	Various Companies	Various Companies	OS	OATT	System	System		0	
18	⁽²⁾ See Footnote					⁽²⁾ See Footnote			0	
35	TOTAL							0	(28,535)	232,329

Line No.	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)
1	9,510			9,510
2	25,420			25,420
3	7,507			7,507
4	15,844			15,844
5	1,518			1,518
6	21,142			21,142
7	5,319			5,319
8	11,209			11,209
9	89,726			89,726
10	25,886			25,886
11	1,651			1,651
12		209,239	841,254	1,050,493
13				
14				
15				
16			5,220,053	5,220,053
17			45,380,208	45,380,208
18				
35	214,732	209,239	51,441,515	51,865,486

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Lines 1-10 Otter Tail Power Company wheels WAPA's portion of customers' load.
Line 11 Otter Tail Power Company wheels WAPA's total load to customer.
Line 12 Otter Tail Power Company wheels MPC's total load to various interconnects
Lines 13 - 15 contain losses and regulation that result from interconnects with various companies in the integrated system.

(b) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Various companies. Miscellaneous losses - mwh received.

(c) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Generator Interconnection Agreements and/or Facility Service Agreements between various parties

(d) Concept: RateScheduleTariffNumber

Original Service Agreement No. 30 under Otter Tail Power Company FERC Electric Tariff, Original Volume No. 1

(e) Concept: TransmissionPointOfReceipt

(1) Various points of interconnect in the intergrated system

(f) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Midwest Independent System Operator Transmission

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1	Not Applicable				
40	TOTAL				

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

- Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
- In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
- In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
- Enter ""TOTAL"" in column (a) as the last line.
- Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Otter Tail Power Company	FNS					\$23,948,321	23,948,321
2	Montana-Dakota Utilities Co.	OS					\$775,140	775,140
3	Central Power Electric Cooperative, Inc	FNS				25,660		25,660
4	PKM Electric Coop Inc.	FNS		555		2,619		2,619
	TOTAL		0	555	0	28,279	24,723,461	24,751,740

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

The expenses incurred are for transmission of electricity and supporting services provided by the Midcontinent Independent System Operator and the Southwest Power Pool.

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

The expenses incurred are for facility service agreement fees.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	391,690
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	19,949
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	289,682
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Miscellaneous labor	59,315
7	Public Relations Expenses:	
8	Labor	18,676
9	Items less than \$5,000 each	20,036
10	Director Fees and Expense:	
11	Director Fees	509,023
46	TOTAL	1,308,371

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

- Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
- Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,904,889		3,904,889
2	Steam Production Plant	14,783,298	86,825			14,870,123
3	Nuclear Production Plant					
4	Hydraulic Production Plant- Conventional	142,589				142,589
5	Hydraulic Production Plant- Pumped Storage					
6	Other Production Plant	23,984,699	545,117			24,529,816
7	Transmission Plant	12,370,979				12,370,979
8	Distribution Plant	14,840,562				14,840,562
9	Regional Transmission and Market Operation					
10	General Plant	3,221,786				3,221,786
11	Common Plant-Electric					
12	TOTAL	69,343,913	631,942	3,904,889		73,880,744

B. Basis for Amortization Charges

The \$3,904,889 Amortization of limited term Electric Plant is: Franchise Consents (302): \$49,961 for hydro plant license with a remaining life of 40 years at a rate of 2.50%; Miscellaneous Intangible Plant (303): \$971,220 for computer software with a 5-year service life at a rate of 20.0%; \$2,884,653 for computer software with a 10-year service life at a rate of 10.0%; (\$825) Amortization of Ashtabula III Acquisition Adjustment

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production -						
13	Big Stone Plant -						
14	311	46,286	34 years, 6 months, 11 days	(5.7)%	2.78%	SQ	22 years, 8 months, 23 days
15	312	147,293	32 years, 5 months, 27 days	(5.7)%	3.49%	SQ	22 years, 8 months, 23 days
16	314	10,457	41 years, 6 months, 15 days	(5.7)%	1.74%	SQ	22 years, 8 months, 16 days
17	315	10,836	36 years, 7 months, 21 days	(5.7)%	2.51%	SQ	22 years, 8 months, 19 days
18	316	1,942	37 years, 2 months, 12 days	(5.7)%	2.71%	SQ	22 years, 8 months, 19 days
19	Hoot Lake Plant -						
20	312 - Units 2, 3	6,375	35 years, 11 months, 12 days		2.24%	SQ	27 years, 4 months, 21 days
21	Coyote Plant -						
22	311	7,516	49 years, 4 months, 2 days	(8.7)%	1.68%	SQ	17 years, 11 months, 23 days
23	312	37,435	39 years, 8 months, 1 day	(8.7)%	2.42%	SQ	17 years, 11 months, 27 days
24	314	9,058	37 years, 4 months, 13 days	(8.7)%	2.58%	SQ	18 years
25	315	2,873	46 years, 6 months, 7 days	(8.7)%	1.8%	SQ	17 years, 11 months, 27 days
26	316	1,411	30 years, 7 months, 10 days	(8.7)%	3.7%	SQ	18 years, 4 days
27	STEAM PROD	281,482					
28	Hydro Production -						
29	Hoot Lake Hydro -						
30	331	1	98 years, 2 months, 9 days		0.03%	SQ	37 years, 11 days
31	332	411	81 years, 4 months, 17 days		1.57%	SQ	37 years, 1 month, 28 days
32	333	1	72 years, 9 months, 26 days		0.03%	SQ	37 years, 2 months, 23 days
33	334	485	40 years, 1 month, 10 days		2.44%	SQ	37 years, 5 months, 9 days
34	335	4	46 years, 11 months, 27 days		0.23%	SQ	37 years, 4 months, 24 days
35	Wright Hydro -						
36	331	1	72 years, 11 months, 23 days		0.2%	SQ	37 years, 2 months, 19 days
37	332	69	51 years, 8 months, 1 day		0.21%	SQ	37 years, 4 months, 13 days
38	333	16	48 years, 11 months, 12 days		0.08%	SQ	37 years, 4 months, 21 days
39	334	8	55 years, 2 months, 19 days		0.11%	SQ	37 years, 4 months, 6 days
40	335	7	53 years, 1 month, 10 days		0.17%	SQ	37 years, 4 months, 10 days
41	Pisgah Hydro -						
42	331	1	78 years, 9 months, 7 days		0.26%	SQ	37 years, 2 months, 5 days
43	332	2,562	41 years, 3 months, 11 days		3.25%	SQ	37 years, 5 months, 5 days
44	333	8	54 years, 1 month, 28 days		0.14%	SQ	37 years, 4 months, 6 days
45	334	5	54 years, 4 days		0.13%	SQ	37 years, 4 months, 6 days
46	335	6	46 years, 11 months, 27 days		0.24%	SQ	37 years, 4 months, 24 days
47	Dayton Hollow Hydro -						
48	331	152	47 years, 11 months, 19 days		2.73%	SQ	37 years, 4 months, 21 days
49	332	1,243	46 years, 7 months, 17 days		1.35%	SQ	37 years, 4 months, 24 days

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
50	333	11	53 years, 29 days		0.13%	SQ	37 years, 4 months, 10 days
51	334	7	59 years, 7 months, 24 days		0.09%	SQ	37 years, 3 months, 26 days
52	335	9	47 years, 18 days		0.22%	SQ	37 years, 4 months, 24 days
53	Taplin Gorge Hydro -						
54	331		108 years, 8 months, 27 days		0.02%	SQ	36 years, 11 months, 12 days
55	332	29	62 years, 3 months, 22 days		0.13%	SQ	37 years, 3 months, 15 days
56	333		113 years, 6 months		0.02%	SQ	36 years, 10 months, 28 days
57	334	2	62 years, 11 months, 12 days		0.08%	SQ	37 years, 3 months, 18 days
58	335	6	51 years, 5 months, 16 days		0.17%	SQ	37 years, 4 months, 13 days
59	HYDRO PROD	5,044					
60	Other Production -						
61	Jamestown Peaking #1 -						
62	341	42	35 years, 10 months, 2 days	(5.8)%	2%	SQ	10 years, 3 months, 26 days
63	342	97	28 years, 3 months, 15 days	(5.8)%	3.04%	SQ	10 years, 3 months, 29 days
64	343	441	38 years, 4 days	(5.8)%	1.97%	SQ	10 years, 3 months, 26 days
65	345	20	56 years, 3 months, 4 days	(5.8)%	1.78%	SQ	10 years, 3 months, 22 days
66	346	28	22 years, 4 months, 21 days	(5.8)%	3.7%	SQ	10 years, 3 months, 29 days
67	Lake Preston Peaking -						
68	341	82	42 years, 2 months, 23 days	(6.9)%	3.39%	SQ	10 years, 3 months, 26 days
69	342	37	39 years, 10 months, 24 days	(6.9)%	1.75%	SQ	10 years, 3 months, 26 days
70	343	307	43 years, 2 months, 23 days	(6.9)%	1.58%	SQ	10 years, 3 months, 26 days
71	345	40	42 years, 2 months, 19 days	(6.9)%	1.64%	SQ	10 years, 3 months, 26 days
72	346	1	48 years, 8 months, 23 days	(6.9)%	0.99%	SQ	10 years, 3 months, 26 days
73	Jamestown Peaking #2 -						
74	341	6	27 years, 8 months, 5 days	(5.8)%	3.08%	SQ	10 years, 3 months, 29 days
75	342	3	30 years, 10 months, 13 days	(5.8)%	1.37%	SQ	10 years, 3 months, 26 days
76	343	380	43 years, 3 months, 29 days	(5.8)%	1.5%	SQ	10 years, 3 months, 26 days
77	345	28	21 years, 3 months, 11 days	(5.8)%	4.32%	SQ	10 years, 3 months, 29 days
78	346		45 years, 10 months, 13 days	(5.8)%	(0.2)%	SQ	10 years, 3 months, 26 days
79	Solway Combustion Turbine -						
80	341	2,285	31 years, 2 months, 19 days	(1.6)%	3.24%	SQ	15 years, 1 month, 24 days
81	342	718	31 years, 2 months, 5 days	(1.6)%	3.86%	SQ	15 years, 1 month, 24 days
82	343	12,073	30 years, 1 month, 2 days	(1.6)%	3.95%	SQ	15 years, 1 month, 24 days
83	345	613	32 years, 4 months, 10 days	(1.6)%	3.2%	SQ	15 years, 1 month, 21 days
84	346	162	29 years, 9 months, 4 days	(1.6)%	3.46%	SQ	15 years, 1 month, 24 days
85	Astoria Station -						
86	341	23,845	33 years, 5 months, 19 days	(1.7)%	3.02%	SQ	32 years, 4 days

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
87	342	5,611	33 years, 5 months, 19 days	(1.7)%	3.02%	SQ	32 years, 4 days
88	343	102,392	33 years, 5 months, 19 days	(1.7)%	3.02%	SQ	32 years, 4 days
89	345	7,013	33 years, 5 months, 19 days	(1.7)%	3.02%	SQ	32 years, 4 days
90	346	1,403	33 years, 5 months, 19 days	(1.7)%	3.02%	SQ	32 years, 4 days
91	Langdon Wind Energy Center -						
92	341	1,059	33 years, 8 months, 23 days	(4.9)%	2.51%	SQ	18 years, 11 months, 16 days
93	344	31,897	32 years, 11 months, 19 days	(4.9)%	2.66%	SQ	18 years, 11 months, 16 days
94	345	3,220	33 years, 3 months, 11 days	(4.9)%	2.55%	SQ	18 years, 11 months, 16 days
95	346	126	23 years, 29 days	(4.9)%	5.87%	SQ	18 years, 11 months, 19 days
96	Ashtabula Wind Energy Center -						
97	341	1,507	33 years, 8 months, 12 days	(4.2)%	2.54%	SQ	19 years, 10 months, 24 days
98	344	52,496	33 years, 2 months, 27 days	(4.2)%	2.66%	SQ	19 years, 10 months, 24 days
99	345	3,055	33 years, 3 months, 11 days	(4.2)%	2.58%	SQ	19 years, 10 months, 24 days
100	346	110	22 years, 10 months, 13 days	(4.2)%	5.54%	SQ	19 years, 11 months, 1 day
101	Luverne Wind Energy Center -						
102	341	1,112	33 years, 7 months, 28 days	(7)%	2.69%	SQ	20 years, 10 months, 6 days
103	344	37,424	32 years, 9 months, 7 days	(7)%	2.92%	SQ	20 years, 10 months, 6 days
104	345	2,387	33 years, 7 months, 28 days	(7)%	2.69%	SQ	20 years, 10 months, 6 days
105	346	153	24 years, 10 months, 13 days	(7)%	5.24%	SQ	20 years, 10 months, 10 days
106	Merricourt Wind Energy Center -						
107	341	7,329	33 years, 5 months, 19 days	(5)%	3.18%	SQ	31 years, 1 month, 2 days
108	344	219,874	33 years, 5 months, 19 days	(5)%	3.18%	SQ	31 years, 1 month, 2 days
109	345	17,101	33 years, 5 months, 19 days	(5)%	3.18%	SQ	31 years, 1 month, 2 days
110	346	11	33 years, 5 months, 19 days	(5)%	3.34%	SQ	31 years, 1 month, 2 days
111	Ashtabula III Wind Energy Center -						
112	341	2,546	25 years, 6 months		2.72%	SQ	25 years, 6 months
113	344	44,716	25 years, 6 months		2.72%	SQ	25 years, 6 months
114	345	4,445	25 years, 6 months		2.72%	SQ	25 years, 6 months
115	346	140	25 years, 6 months		2.72%	SQ	25 years, 6 months
116	Hoot Lake Solar -						
117	341	1,838	35 years, 6 months	8.1%	2.59%	SQ	35 years, 6 months
118	345	56,973	35 years, 6 months	8.1%	2.59%	SQ	35 years, 6 months
119	346	613	35 years, 6 months	8.1%	2.59%	SQ	35 years, 6 months
120	Minnesota Dakota Small Solar -						
121	341	12	24 years, 2 months, 19 days	(1)%	4.24%	SQ	21 years, 9 months, 22 days
122	345	130	24 years, 2 months, 19 days	(1)%	4.24%	SQ	21 years, 9 months, 22 days
123	North Dakota Small Solar -						

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
124	341	15	24 years, 2 months, 23 days	(1)%	4.34%	SQ	20 years, 10 months, 10 days
125	345	135	24 years, 2 months, 23 days	(1)%	4.34%	SQ	20 years, 10 months, 10 days
126	OTHER PROD	648,051					
127	Transmission Plant -						
128	350.1	20,046	70 years		1.43%		
129	353	150,481	65 years, 1 month, 13 days	(5)%	1.56%	R1	56 years, 4 days
130	354	177,777	75 years	(10)%	1.45%	R5	69 years, 1 month, 17 days
131	355	106,470	75 years, 3 months	(50)%	1.86%	R2	60 years, 10 months, 6 days
132	356	133,626	75 years, 1 month, 6 days	(30)%	1.63%	R2	62 years, 8 months, 16 days
133	358	26	51 years, 4 days	(5)%	1.44%	S4	20 years, 8 months, 1 day
134	SUBTOTAL	588,426					
135	Distribution Plant -						
136	362	68,372	43 years, 6 months, 7 days	5%	1.94%	SC	34 years, 5 months, 16 days
137	364	35,319	70 years, 1 month, 6 days	(100)%	2.92%	R3	48 years, 1 month, 13 days
138	365	15,349	65 years, 2 months, 27 days	(75)%	2.33%	R2.5	43 years, 22 days
139	367	69,630	44 years, 11 months, 9 days	(5)%	2.22%	R4	29 years, 7 months, 13 days
140	368	107,148	43 years, 4 days	30%	1.73%	R2.5	30 years, 6 months, 11 days
141	369	(4,590)	55 years, 5 months, 1 day	(200)%	5.79%	S5	28 years, 11 months, 5 days
142	369.1	26,596	50 years, 1 month, 28 days	(20)%	2.25%	R4	32 years, 6 months, 22 days
143	370	17,228	29 years, 2 months, 16 days		3.21%	L1	19 years, 1 month, 2 days
144	370.05	745	20 years		4.88%	S3	16 years, 6 months, 26 days
145	370.1	49	16 years, 8 months, 27 days		0.39%	R5	1 year, 5 months, 1 day
146	370.2		5 years		20%	SQ - Amortized	0 days
147	371.1	18	10 years		10%	SQ - Amortized	7 years, 6 months
148	371.2	9,127	25 years, 3 months, 4 days		3.87%	O3	24 years, 6 months, 7 days
149	373	11,415	22 years, 2 months, 1 day	(5)%	4.93%	L0.5	18 years, 6 months, 4 days
150	SUBTOTAL	356,406					
151	General Plant -						
152	390	15,889	51 years, 29 days	5%	2%	R1	32 years, 5 months, 9 days
153	390.1	3,800	36 years, 7 months, 21 days	43.1%	0.94%	SQ	17 years, 18 days
154	390.2	307	47 years, 6 months, 22 days	55.6%	(0.66)%	SQ	21 years, 9 months, 4 days
155	390.25	2,065	55 years, 6 months, 4 days	50%	0.88%	SQ	52 years, 4 months, 2 days
156	390.3	2,746	54 years, 11 months, 5 days	75.8%	(0.53)%	SQ	21 years, 8 months, 27 days
157	391	137	15 years		6.67%	SQ - Amortized	5 years, 4 months, 21 days
158	391.1	91	10 years		10%	SQ - Amortized	4 years, 6 months, 15 days
159	391.2	278	10 years		10%	SQ - Amortized	4 years, 2 months, 5 days
160	391.5	1,661	5 years		20%	SQ - Amortized	2 years, 4 months, 6 days

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
161	391.6	1,263	5 years		20%	SQ - Amortized	2 years, 4 months, 24 days
162	392	20,406					
163	Aircraft	1,671	10 years	25%			
164	Autos		5 years	15%			
165	Light Trucks		10 years	10%			
166	Heavy Trucks & Semi		10 years	15%			
167	Tractors (Includes		10 years	15%			
168	Cranes)						
169	Trailers		15 years	10%			
170	Portable Oil Purifier		10 years	20%			
171	Trenchers		10 years	10%			
172	Misc. Light Equip.		10 years	10%			
173	Misc. Heavy Equip.		15 years	15%			
174	394	2,555	15 years		6.67%	SQ - Amortized	6 years, 11 months, 9 days
175	394.2	282	15 years		6.67%	SQ - Amortized	5 years, 18 days
176	395		15 years		6.67%	SQ - Amortized	0 days
177	396	1,389	23 years, 5 months, 16 days	5%	3.89%	L0	19 years, 8 months, 9 days
178	397	3,195	15 years		6.67%	SQ - Amortized	10 years, 18 days
179	397.1	202	10 years		10%	SQ - Amortized	1 year
180	397.2	1,751	15 years		6.67%	SQ - Amortized	6 years, 11 months, 23 days
181	397.3	79	10 years		10%	SQ - Amortized	4 years, 8 months, 9 days
182	397.4	860	50 years, 5 months, 27 days	(5)%	1.67%	R2.5	29 years, 8 months, 27 days
183	SUBTOTAL	60,627					
184	TOTAL	1,940,036					
185	SUBACCOUNTS USED						

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

SUBACCOUNTS USED

312.1	Ash Landfills
350.1	Easements
369.1	Underground Services
370.1	Load Management Switches
370.2	Interruption Monitors
371.2	All Other Private Lighting
390.1	General Office Building
390.2	Fleet Service Center Building - Fergus Falls
390.3	Fleet Service Center Building - Jamestown
390.3	Central Stores Building
391.1	Office Equipment
391.2	Duplicating Equipment
391.5	Computer Systems
391.6	Computer Related Equipment
394.2	AMR Equipment
397.1	Radio Telecommunication Equipment
397.2	Microwave Equipment
397.3	Radio Load Control Equipment
397.4	Communication Towers

Column (b) is the balance of plant in service (except land) at the beginning of the year, less the associated reserve for accumulated depreciation and includes amounts tentatively classified in Account 106, Completed Construction Not Classified.

Column (e) rates are applied to the original cost per books (Accounts 101 and 106) from the close of the prior month except when major additions and retirements occur which significantly affect depreciation expense.

Column (d) factors are a composite of rates allowed in the jurisdictions served.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	MN Dept. of Commerce/Public Utilities Commission	604,028		604,028		Electric	928	604,028				
2	Administrative Cost Assessment Fees					Electric	928					
3	E017/GR-15-1033 (MN Rate Case; BSAT/MVP Appeal)	7,884		7,884	1,131,280	Electric	928	7,884			377,093	754,187
4	MN FCA Forecast		34,659	34,659		Electric	928	34,659				
5	E017-RP-21-339 - Integrated Resource Plan 2022-2036		163,424	163,424		Electric	928	163,424				
6	E017-M-21-382 (MN Electric Utility Infrastructure Costs)		4,636	4,636		Electric	928	4,636				
7	E017-M-21-99 (Energy Intensive Trade Exposed Customer Rate)		1,787	1,787		Electric	928	1,787				
8	M-23-261 - MN TOD Pilot		25,957	25,957		Electric	929	25,957				
9	E017/M-23-076 - MN 2022 SRSQ		18,831	18,831		Electric	928	18,831				
10	Miscellaneous - MN		360,246	360,246		Electric	928	360,246				
11	ND Public Service Commission	48,500		48,500		Electric	928	48,500				
12	Administrative Cost Assessment Fees					Electric	928					
13	PU-17-398 (ND Rate Case)		9,464	9,464		Electric	928	9,464				
14	PU-23-283 - ND AMDT		12,269	12,269		Electric	928	12,269				
15	PU-23-306 - ND TCR		37,698	37,698		Electric	928	37,698				
16	Miscellaneous - ND		18,530	18,530		Electric	928	18,530				
17	SD Public Service Commission	76,529		76,529		Electric	928	76,529				
18	Administrative Cost Assessment Fees					Electric	928					
19	EL23-033 (SD TCR)		8,035	8,035		Electric	928	8,035				
20	EL23-015 - Phase In Rider		18,895	18,895		Electric	928	18,895				
21	Miscellaneous - SD		5,885	5,885		Electric	928	5,885				
22	Federal Energy Regulatory Commission:											
23	MISO Schedule 10		511,219	511,219		Electric	928	511,219				
24	SPP Schedule 12		21,269	21,269		Electric	928	21,269				
25	North American Electric Reliability Corporation	305,334		305,334		Electric	928	305,334				
26	FERC/RTO Policy		51,527	51,527		Electric	928	51,527				
46	TOTAL	1,042,275	1,304,331	2,346,606	1,131,280			2,346,606			377,093	754,187

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: DeferredRegulatoryCommissionExpensesAmortized

Amortized period is Jan 2021 through Dec 2025

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

- Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
- Indicate in column (a) the applicable classification, as shown below:
Classifications:

A. Electric R, D and D Performed Internally:

1. Generation

a. hydroelectric

- i. Recreation fish and wildlife
- ii. Other hydroelectric

- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Unconventional generation
- f. Siting and heat rejection

2. Transmission

- a. Overhead
- b. Underground

- 3. Distribution
- 4. Regional Transmission and Market Operation
- 5. Environment (other than equipment)
- 6. Other (Classify and include items in excess of \$50,000.)
- 7. Total Cost Incurred

B. Electric, R, D and D Performed Externally:

- 1. Research Support to the electrical Research Council or the Electric Power Research Institute
- 2. Research Support to Edison Electric Institute
- 3. Research Support to Nuclear Power Groups
- 4. Research Support to Others (Classify)
- 5. Total Cost Incurred

- Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
- Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
- Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
- If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
- Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	Electric Utility R&D						
2	PERFORMED INTERNALLY:						
3	Other	Miscellaneous	2,302		506.0	2,302	
4	Other	Miscellaneous					
5	PERFORMED EXTERNALLY:						
6		E Source Companies LLC		19,949	930.2	19,949	
7	TOTAL:		2,302	19,949		22,251	

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	6,821,743		
4	Transmission	4,202,504		
5	Regional Market	750,621		
6	Distribution	5,434,238		
7	Customer Accounts	6,547,667		
8	Customer Service and Informational	1,618,847		
9	Sales	194,553		
10	Administrative and General	31,160,199		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	56,730,372		
12	Maintenance			
13	Production	4,247,467		
14	Transmission	2,050,574		
15	Regional Market	43,231		
16	Distribution	5,653,291		
17	Administrative and General	1,857,711		
18	TOTAL Maintenance (Total of lines 13 thru 17)	13,852,274		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,069,210		
21	Transmission (Enter Total of lines 4 and 14)	6,253,078		
22	Regional Market (Enter Total of Lines 5 and 15)	793,852		
23	Distribution (Enter Total of lines 6 and 16)	11,087,529		
24	Customer Accounts (Transcribe from line 7)	6,547,667		
25	Customer Service and Informational (Transcribe from line 8)	1,618,847		
26	Sales (Transcribe from line 9)	194,553		
27	Administrative and General (Enter Total of lines 10 and 17)	33,017,910		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	70,582,646		70,582,646
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	70,582,646		70,582,646
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	22,561,711		22,561,711
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	22,561,711		22,561,711
72	Plant Removal (By Utility Departments)			
73	Electric Plant	67,294		67,294
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	67,294		67,294
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Fuel Stock (151)			
80	Miscellaneous Deferred Debits (186)	1,125,392		1,125,392
81	Other Electric Revenue (456)	264,581		264,581
82	Expenses of Nonutility Operations (417.1)	59,125		59,125
83	Exp. for Certain Civic, Political and Related Activity (426.4)	152,841		152,841
84	Other Deductions (426.5)	271,682		271,682
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,873,621		1,873,621
96	TOTAL SALARIES AND WAGES	95,085,272		95,085,272

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

[\(a\)](#) Concept: SalariesAndWagesOtherAccountsDescription
Salaries and wages are included in the specified accounts because they are either not provided for elsewhere, are nonutility in nature, or are nonoperating.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Not Applicable

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	MISO				
8	Energy				
9	Net Purchases (Account 555)	33,424,774	52,660,090	68,878,414	106,238,630
10	Net Sales (Account 447)	(1,695,927)	(4,203,101)	(8,769,639)	(11,861,790)
11	Transmission Rights (555)	(9,856,863)	(20,514,511)	(29,548,915)	(51,753,320)
12	Transmission Rights (447)				
13	Ancillary Services (555)	75,626	(114,172)	(355,653)	(393,895)
14	Ancillary Services (447)				
15	Other Items (list separately) (555)	(1,703,579)	(3,113,806)	(2,757,263)	(2,199,215)
16	Other Items (list separately) (447)	(71,075)	(202,941)	(357,991)	(416,932)
17	SPP				
18	Net Purchases (Account 555)	184,522	304,228	980,434	1,202,666
19	Net Sales (Account 447)				
20	Transmission Rights (555)		(279,464)	(279,464)	(279,464)
21	Ancillary Services (555)	15	34	36	58
22	Other Items (list separately) (555)	18	(178)	(154)	(37)
46	TOTAL	20,357,511	24,536,179	27,789,805	40,536,701

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff. In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			135,687	1,334,359	\$/MW-Hr	219,502
2	Reactive Supply and Voltage				4,397,763	\$/MW-Hr	659,664
3	Regulation and Frequency Response				0	\$/MW-Hr	
4	Energy Imbalance				0	0	
5	Operating Reserve - Spinning				0	0	
6	Operating Reserve - Supplement				0	0	
7	Other				0	\$/MW-Hr	
8	Total (Lines 1 thru 7)			135,687	5,732,122		879,166

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	958	31	9	957	1				
2	February	961	2	8	960	1				
3	March	898	29	8	897	1				
4	Total for Quarter 1				2,814	3				
5	April	752	19	11	751	1				
6	May	759	31	15	758	1				
7	June	814	19	18	813	1				
8	Total for Quarter 2				2,322	3				
9	July	836	24	15	835	1				
10	August	837	2	18	836	1				
11	September	817	4	18	816	1				
12	Total for Quarter 3				2,487	3				
13	October	872	31	10	871	1				
14	November	907	27	18	906	1				
15	December	901	18	9	900	1				
16	Total for Quarter 4				2,677	3				
17	Total				10,300	12				
	NAME OF SYSTEM: Not Applicable									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total									

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

The peak numbers for October through December are estimated and are from MISO's S-55, S-14, or S-7 settlement data.

FERC FORM NO. 1 (NEW. 07-04)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Not Applicable									
1	January	0								
2	February	0								
3	March	0								
4	Total for Quarter 1									
5	April	0								
6	May	0								
7	June	0								
8	Total for Quarter 2									
9	July	0								
10	August	0								
11	September	0								
12	Total for Quarter 3									
13	October	0								
14	November	0								
15	December	0								
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 2023-12-31	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	5,772,215
3	Steam	1,759,137	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,001
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	368,112
5	Hydro-Conventional	8,846	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	21,179
7	Other	1,751,930	27	Total Energy Losses	(117,769)
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	3,519,913	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	6,046,738
10	Purchases (other than for Energy Storage)	2,787,689			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	(28,534)			
17	Delivered	232,330			
18	Net Transmission for Other (Line 16 minus line 17)	(260,864)			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	6,046,738			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2023-12-31	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: EnergyLosses

Includes all retail, wholesale, and transmission wheeling service system losses, losses on other systems due to sales for resale, and inadvertent energy imbalances.

(b) Concept: ElectricPowerWheelingEnergyReceived

Includes interchange transactions and losses thereon.

(c) Concept: ElectricPowerWheelingEnergyDelivered

Includes interchange transactions and losses thereon.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	758,328	8,722	958	31	9
30	February	558,090	17,854	961	2	8
31	March	548,935	36,753	898	29	8
32	April	511,287	21,466	752	19	11
33	May	458,235	43,859	759	31	15
34	June	475,740	24,604	814	19	18
35	July	493,179	51,151	836	24	15
36	August	455,765	40,586	837	2	18
37	September	405,926	31,800	817	4	18
38	October	498,953	32,741	872	31	10
39	November	342,837	27,238	907	27	18
40	December	539,463	31,338	901	18	9
41	Total	6,046,738	368,112			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0	Plant Name: Astoria	Plant Name: Big Stone	Plant Name: Coyote	Plant Name: Jamestown	Plant Name: Lake Preston	Plant Name: Solway
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		Gas Turbine	Steam	Steam	Gas Turbine	Gas Turbine	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Conventional	Conventional	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed		2021	1975	1981	1976	1978	2003
4	Year Last Unit was Installed		2021	1975	1981	1978	1978	2003
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		245	223	145	48	24	45
6	Net Peak Demand on Plant - MW (60 minutes)		285	256	152	38	18	47
7	Plant Hours Connected to Load		1,845	6,606	7,841	98	14	4,264
8	Net Continuous Plant Capability (Megawatts)		250	257	148	41	19	42
9	When Not Limited by Condenser Water		250	257	148	41	19	42
10	When Limited by Condenser Water		250	257	148	41	19	42
11	Average Number of Employees		4	77	77	0	0	2
12	Net Generation, Exclusive of Plant Use - kWh		407,228,960	858,441,035	900,695,576	869,386	76,278	163,387,025
13	Cost of Plant: Land and Land Rights			380,568	713,587	24,614	12,339	89,809
14	Structures and Improvements		25,452,349	81,059,803	35,004,316	311,512	279,726	4,907,301
15	Equipment Costs		122,811,197	259,159,725	148,271,056	7,901,036	4,227,423	24,647,998
16	Asset Retirement Costs		1,072,896	354,996	4,310,212		0	
17	Total cost (total 13 thru 20)		149,336,442	340,955,092	188,299,171	8,237,162	4,519,488	29,645,108
18	Cost per KW of Installed Capacity (line 17/5) Including		610	1,529	1,299	172	188	659
19	Production Expenses: Oper, Supv, & Engr		320	566,961	784,947	2,604	10,150	285
20	Fuel		12,317,724	21,293,280	22,274,968	419,142	24,083	3,832,035
21	Coolants and Water (Nuclear Plants Only)						0	
22	Steam Expenses			2,149,508	2,491,594		0	
23	Steam From Other Sources						0	
24	Steam Transferred (Cr)						0	
25	Electric Expenses		207,700	870,557	790,447	9,032	1,755	186,367
26	Misc Steam (or Nuclear) Power Expenses		238,060	1,878,273	753,354	20,320	2,567	509,350
27	Rents		903		5,006		0	129
28	Allowances						0	
29	Maintenance Supervision and Engineering		8,290	318,461	238,293	2,051	0	7,738
30	Maintenance of Structures		22,563	270,906	433,754	4,114	426	22,676
31	Maintenance of Boiler (or reactor) Plant			2,809,488	2,707,924		0	
32	Maintenance of Electric Plant		751,856	1,243,909	219,254	150,311	48,152	300,736
33	Maintenance of Misc Steam (or Nuclear) Plant		62,024	475,414	581,306	1,609	1,462	6,989
34	Total Production Expenses	0	13,609,440	31,876,757	31,280,847	609,183	88,595	4,866,305
35	Expenses per Net kWh	0.0000	0.0334	0.0371	0.0347	0.7007	1.1615	0.0298

35	Plant Name	Astoria	Big Stone	Big Stone	Coyote	Coyote	Jamestown	Lake Preston	Solway	Solway
36	Fuel Kind	Natural Gas	Coal	Oil	Coal	Oil	Oil	Oil	Natural Gas	Oil
37	Fuel Unit	MMBTU	T	bbl	T	bbl	bbl	bbl	MMBTU	bbl
38	Quantity (Units) of Fuel Burned	4,257,380	596,793	4,226	756,001	3,621	3,093	254	1,638,677	125
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,865,700	8,204	140,000	7,022	140,000	140,000	140,000	1,639,495	140,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.900	37.680	143.560	28.672	122.430	114.744	142.630	2.310	139.100
41	Average Cost of Fuel per Unit Burned	2.910	36.509	139.100	28.731	139.818	123.586	94.790	2.330	104.328
42	Average Cost of Fuel Burned per Million BTU	2.910	2.225	23.656	2.046	23.779	21.018	16.121	2.330	17.743
43	Average Cost of Fuel Burned per kWh Net Gen	0.030	0.025	0.000	0.025	0.000	0.482	0.316	0.023	
44	Average BTU per kWh Net Generation	10,455.000	11,335.000	0.000	11,842.000	0.000	20,919.000	19,580.000	10,034.000	
Page 402-403										

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: PlantName

Big Stone - Jointly owned facility operated by Otter Tail Power Company

(b) Concept: PlantName

Coyote - Jointly owned facility operated by Otter Tail Power Company

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	(2) <input type="checkbox"/> A Resubmission		

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 0 Plant Name: Not Applicable
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0	0
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - kWh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	Total cost (total 13 thru 20)	0.0000	0.0000
21	Cost per KW of Installed Capacity (line 20 / 5)		
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net kWh	0	0

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2) <input type="checkbox"/> A Resubmission		

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWh as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. Not Applicable Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)		
2	Year Originally Constructed		
3	Year Last Unit was Installed		
4	Total installed cap (Gen name plate Rating in MW)		
5	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
6	Plant Hours Connect to Load While Generating	0	0
7	Net Plant Capability (in megawatts)	0	0
8	Average Number of Employees		
9	Generation, Exclusive of Plant Use - kWh	0	0
10	Energy Used for Pumping		
11	Net Output for Load (line 9 - line 10) - Kwh	0	0
12	Cost of Plant		
13	Land and Land Rights		
14	Structures and Improvements	0	0
15	Reservoirs, Dams, and Waterways	0	0
16	Water Wheels, Turbines, and Generators	0	0
17	Accessory Electric Equipment	0	0
18	Miscellaneous Powerplant Equipment	0	0
19	Roads, Railroads, and Bridges	0	0
20	Asset Retirement Costs	0	0
21	Total cost (total 13 thru 20)		
22	Cost per KW of installed cap (line 21 / 4)		
23	Production Expenses		
24	Operation Supervision and Engineering	0	0
25	Water for Power	0	0
26	Pumped Storage Expenses	0	0
27	Electric Expenses	0	0
28	Misc Pumped Storage Power generation Expenses	0	0
29	Rents	0	0
30	Maintenance Supervision and Engineering	0	0
31	Maintenance of Structures	0	0
32	Maintenance of Reservoirs, Dams, and Waterways	0	0
33	Maintenance of Electric Plant	0	0
34	Maintenance of Misc Pumped Storage Plant	0	0
35	Production Exp Before Pumping Exp (24 thru 34)		
36	Pumping Expenses		
37	Total Production Exp (total 35 and 36)		
38	Expenses per kWh (line 37 / 9)		
39	Expenses per kWh of Generation and Pumping (line 37/(line 9 + line 10))	0	0

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2) <input type="checkbox"/> A Resubmission		

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l))	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	Hydro:												
2	Hoot Lake Hydro	1914	0.67	0.70	1,815	3,525,341	5,036,202	6,694		74,819			Hydro
3	Wright Hydro	1922	0.40	0.00	(66)	1,860,735		7,391		33,186			Hydro
4	Pisgah Hydro	1917	0.65	0.60	1,935	2,528,943	4,214,905	6,094		39,077			Hydro
5	Dayton Hollow Hydro	1909	0.97	0.50	3,539	2,856,591	5,713,181	8,191		43,469			Hydro
6	Taplin Gorge Hydro	1925	0.56	0.50	1,625	1,060,477	2,120,953	6,332		63,149			Hydro
7	Wind Turbine Plants:												
8	Langdon	2007	40.50	33.90	104,744	82,393,852	2,430,497	1,210,987		62,872			Wind
9	Ashtabula	2008	48.00	48.50	123,215	118,060,255	2,434,232	1,383,920		49,565			Wind
10	Luverne	2009	49.50	49.90	159,462	76,813,116	1,539,341	1,369,626		42,101			Wind
11	Ashtabula III	2010	48.00	58.30	163,228	83,607,247	1,434,087	1,576,220		66,655			Wind
12	Merricourt	2020	150.00	147.50	594,737	268,871,849	1,822,860	1,556,519		3,899,259			Wind
13	Solar Plants:												
14	Blue Jay Solar	2020	0	0.03	56	168,580	5,619,344						Solar
15	Blue Heron Solar	2020	0	0.03	38	156,123	5,204,086			1,164			Solar
16	Hoot Lake Solar	2023	50	48.60	34,889	62,481,031	1,285,618	29,429		173,180			Solar

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)
1	Not Applicable			0								
35	TOTAL			0	0	0	0	0	0	0	0	0

Line No.	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1							
35	0	0	0		0	0	0
Page 414 Part 2 of 2							

Name of Respondent: Otter Tail Power Company	This report is: (1)	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
36	TOTAL			0	0	0	0	0	0

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)		(f)	(g)		
1									
2	Center	Maple River	345	345	Alum Tower	47.73		1	
3	Alexandria	MN Border	345	345	Steel Tower	0.00		1	
4	Big Stone South	Brookings	345	345	Steel Tower	71.59		1	
5	Big Stone South	Ellendale	345	345	Steel Tower	161.88		1	
6	Brookings	MN Border	345	345	Steel Tower	10.30		1	
7	Cedar Mountain	Helena	345	345	Steel Tower	73.10		2	
8	Cedar Mountain	Lyon County	345	345	Steel Tower	49.50		2	
9	Chub Lake	Hampton	345	345	Steel Tower	18.15		1	
10	Chub Lake	Helena	345	345	Steel Tower	20.92		1	
11	Hazel Creek	Lyon County	345	345	Steel Tower	24.55		1	
12	Lyon County	MN Border	345	345	Steel Tower	48.35		1	
13	MN Border	Bison	345	345	Steel Tower	34.53		1	
14	Monticello	Quarry Sub	345	345	Steel Tower	28.82		1	
15	St. Cloud	Alexandria	345	345	Steel Tower	77.53		1	
16	Fergus Falls	Inman	230	230	Wood H	19.39		1	
17	Fergus Falls	Wahpeton	230	230	Wood H	28.78		1	
18	Wahpeton	Hankinson	230	230	Wood H	27.11		1	
19	Hankinson	Forman	230	230	Wood H	36.46		1	
20	Forman	Ellendale	230	230	Wood H	47.32		1	
21	Audubon (W 1/10)	Badoura	230	230	Wood H	5.71		1	
22	Audubon	Sheyenne	230	230	Wood H	42.34		1	
23	Winger (E 1/3)	Wilton	230	230	Alum Tower	17.51		1	
24	Grand Forks (M 1/3)	Winnipeg	230	230	Wood H	27.10		1	
25	Big Stone (N 1/3)	Hankinson	230	230	Wood H	22.76		1	
26	Big Stone (S 1/4)	Blair	230	230	Wood H	14.96		1	
27	Harvey	Coal Creek	230	230	Wood H	74.87		1	
28	Balta	Harvey	230	230	Wood H	22.46		1	
29	Rugby	Balta	230	230	Steel H	17.86		1	
30	Wilton	Cass Lake	230	230	Steel H	19.34		1	
31	Cass Lake	Boswell	230	230	Steel H	51.19		1	
32	Hazel Creek	MN Valley	230	345	Steel Tower	5.00		1	
33	Big Stone Plant	Big Stone South	230	230	Steel Tower	1.58		1	
34	Big Stone Plant	Big Stone South	230	230	Steel Tower	1.71		1	
35		Total	115	115	Wood H	482.55			
36		Total	115	115	SWP	437.30			
37		Total	115	115	Steel Tower	4.29			
38		Total	69	69		219.85			
39		Total	41.6	41.6	SWP	3,792.00			
40		Total	41.6	41.6	Underground	1.00			
36	TOTAL					6,087	0	35	

Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1				4,754,215	2,912,450	72,876	7,739,541
2		5,840,882	5,840,882				
3	2,908,447	30,054,193	32,962,640				
4	3,602,817	51,741,105	55,343,922				
5	547,832	106,984,929	107,532,761				
6	93,013	1,046,844	1,139,857				
7	1,365,905	6,388,228	7,754,133				
8	483,093	3,984,308	4,467,401				
9	491,533	2,427,110	2,918,643				
10	869,812	2,154,448	3,024,260				
11	156,242	2,072,907	2,229,149				
12	129,317	3,792,375	3,921,692				
13	616,125	8,167,232	8,783,357				
14	2,259,131	8,201,392	10,460,523				
15	2,680,036	23,297,499	25,977,535				
16		2,024,040	2,024,040				
17		2,266,026	2,266,026				
18		2,670,994	2,670,994				
19	366,016	4,937,753	5,303,769				
20		16,208,050	16,208,050				
21		414,677	414,677				
22		1,693,664	1,693,664				
23		1,852,883	1,852,883				
24		969,012	969,012				
25		846,453	846,453				
26		2,354,862	2,354,862				
27		10,973,552	10,973,552				
28		4,433,901	4,433,901				
29		3,486,133	3,486,133				
30	489,732	4,363,752	4,853,484				
31	567,060	10,910,711	11,477,771				
32	47,522	704,213	751,735				
33	53,811	1,022,410	1,076,221				
34	58,247	1,106,693	1,164,940				
35	118,776	16,319,433	16,438,209				
36	2,672,111	38,722,720	41,394,831				
37	15,567	187,032	202,599				
38	53,441	8,758,931	8,812,372				
39		119,742,928	119,742,928				
40		77,461	77,461				
36	20,645,586	513,201,736	533,847,322	4,754,215	2,912,450	72,876	7,739,541

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: OperatingExpensesOfTransmissionLine

Column detail by line not available.

(b) Concept: MaintenanceExpensesOfTransmissionLine

Column detail by line not available.

(c) Concept: RentExpensesOfTransmissionLine

Column detail by line not available.

(d) Concept: OverallExpensesOfTransmissionLine

Column detail by line not available.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under-ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating) (k)
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	
	(a)	(b)		(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Denhoff	McClusky	5.30	41.6 kV	20	3	1	1/0 T2	ACSR	3102 - 4'	42
2	Denhoff	McClusky	(5.30)	Retire							
3	W 1.5 miles of Gackle, ND	W 2.8 miles of Gackle, ND	1.30	Single Pole	19	1	1	1/0RT2	ACSR	3102	42.0
4	W 1.5 miles of Gackle, ND	W 2.8 miles of Gackle, ND	(1)	Retire							
5	W 3.5 miles of Gackle, ND	W 4 miles of Gackle, ND	1	Single Pole, H Structure	19	1	1	1/0RT2	ACSR	3102, 3254, 3651, H Structure	42
6	W 3.5 miles of Gackle, ND	W 4 miles of Gackle, ND	(1)	Retire							
7	S 6.5 miles of Verona, ND	S 6.8 miles of Verona, ND	1	Single Pole	19	1	1	1/0RT2	ACSR	3102, 3254	42
8	S 6.5 miles of Verona, ND	S 6.8 miles of Verona, ND	(1)	Retire							
9	Fergus SE Sub	Buse Switching Station	2	Ductile Iron	22	1	1	266	ACSR	Vertical, 3102	42
10	Fergus SE Sub	Buse Switching Station	(2)	Retire							
44	TOTAL		0		99	7	5				

Line No.	LINE COST					Construction
	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1	290,870	387,680	581,521		1,260,071	Overground
2				(75,236)	(75,236)	Overground
3	11,526	101,615	152,423		265,564	Overground
4				(9,913)	(9,913)	Overground
5	11,526	123,135	184,703		319,364	Overground
6				(5,681)	(5,681)	Overground
7	120	48,209	72,313		120,642	Overground
8				(2,007)	(2,007)	Overground
9	207,740	560,537	840,805		1,609,082	Overground
10				(63,838)	(63,838)	Overground
44	521,782	1,221,176	1,831,765	(156,675)	3,418,048	
Page 424-425 Part 2 of 2						

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(b) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(c) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(d) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(e) Concept: CostOfTransmissionLinesAdded
Estimated total cost.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
1	Astoria, SD - 345 kv - 620483	Transmission		345.00	115.00	43.00	112.00	1	
2	Ashtabula III Substation - 657745	Distribution		241.50	34.50		75.00	1	
3	Bemidji, MN - 115 kv - 63246	Transmission		115.00	69.00	13.80	15.00	1	
4	Big Stone, SD - 230 kv - 620314	Transmission		236.00	118.00	13.80	233.00	1	
5	Big Stone, SD Highway 12 - 115 kv - 63215	Transmission		115.00	43.80	0.00	44.80	1	
6	Big Stone South, SD - 345 kv - 620417	Transmission		345.00	230.00	34.50	896.00	2	
7	Bottineau, ND - 115 kv - 63183	Transmission		115.00	41.60		36.00	2	
8	Browns Valley, MN - 230 kv (Peever) - 63325	Transmission		230.00	43.80		26.88	1	
9	Buffalo, ND - 345 kv - 63258	Transmission		345.00	115.00	41.60	200.00	2	
10	Canby, MN - 115 kv - 63211	Transmission		115.00	43.80		20.00	1	
11	Cass Lake, MN - 115 kv - 63347	Transmission		230.00	76.16	41.60	55.00	2	
12	Cass Lake, MN - 230 kv - 620447	Transmission		230.00	118.00	13.80	187.00	1	
13	Clearbrook, MN - 115 kv - 63241	Transmission		115.00	41.60		10.00	1	
14	Crookston, MN - 115 kv - 63249	Transmission		115.00	41.60		51.00	2	
15	Devils Lake, ND - East 115 kv - 63265	Transmission		115.00	43.80		33.60	1	
16	Devils Lake, ND - SW 115 kv - 224	Transmission		115.00	43.80		30.00	1	
17	Donaldson, MN - 115 kv - 63255	Transmission		115.00	41.60		20.00	2	
18	Erie, ND 230 kv - 620326	Transmission		236.00	118.00	1.80	187.00	1	
19	Fergus Falls, MN - Hoot Lake 115 kv - 63223	Transmission		115.00	43.80		80.00	2	
20	Fertile, MN - 115 kv - 63250	Transmission		115.00	41.60		10.00	1	
21	Finley, ND - Pickert 115 kv - 711	Transmission		230.00	72.00	41.60	60.00	1	
22	Forman, ND - Forman 230 kv - 63363	Transmission		230.00	118.00	43.00	125.00	1	
23	Hensel, ND - 115 kv - 63157	Transmission		115.00	72.00	43.80	33.00	1	
24	Hetland, SD - 115 kv - 63209	Transmission		115.00	43.80		44.80	1	
25	Jamestown, ND - 345 kv - 63369	Transmission		690.00	230.00	87.60	672.00	2	
26	Jamestown, ND - Peaking Plant 115 kv - 63272	Transmission		115.00	69.90		60.00	3	
27	Maple River, ND - 345 kv - 66792	Transmission		345.00	236.00	13.80	180.00	1	
28	Mapleton, ND - 115 kv - 63203	Transmission		115.00	13.10		29.00	2	
29	Marietta, MN - 115 kv - 63213	Transmission		115.00	41.60		10.00	1	
30	Merricourt, ND - 230 kv - 661992	Transmission		230.00	34.50	13.80	167.00	1	
31	New Effington, SD - 620328	Transmission		236.00	43.00		33.60	1	
32	Northwoods, MN - 115kv - 63282	Transmission		115.00	44.00		12.00	1	
33	Oakes, ND - 230 kv - 63362	Transmission		460.00	265.00		67.20	2	
34	Ortonville, MN - 115 kv - 63216	Transmission		115.00	43.80		29.90	1	
35	Pelican Rapids, MN - 115 k - 63234	Transmission		115.00	41.60		10.00	1	
36	Plummer, MN - 115kv - 7967	Transmission		115.00	43.80		18.00	1	
37	Rugby, ND - 230 kv - 620379	Transmission		230.00	115.00	41.60	140.00	1	
38	Rugby, ND - 230 kv - 620379	Transmission		230.00	115.00	13.80	75.00	1	
39	Spiritwood, ND - 620270	Transmission		230.00	56.90		30.80	2	
40	Toronto, SD - 115 kv - 63210	Transmission		115.00	41.60		45.00	1	
41	Wahpeton Inventory	Transmission		115.00	43.80				1
42	Wahpeton, ND - 230 kv - 620329	Transmission		230.00	115.00	43.00	280.00		2
43	WAPA Summit, SD	Transmission		115.00	41.60		25.00	1	
44	Winger, MN 63238	Transmission		230.00	115.00	13.20	327.00	2	
45	Transmission Subs Under 10,000 kva								
46	Colgate	Transmission		69.00	43.80	12.50	6.10	4	
47	Green Valley	Transmission		67.00	41.60		10.00	2	
48	Lake Preston East River	Transmission		69.00	44.00		8.00	1	
49	St Vincent	Transmission		69.00	44.00		7.50	1	
50	Wahpeton Inventory	Transmission		69.00	41.60				1

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
51	Bemidji, MN 25th Street	Distribution		69.00	13.10		15.00	1	
52	Bemidji, MN Airport	Distribution		43.80	13.10		10.00	1	
53	Bemidji, MN Nymore	Distribution		69.00	13.10		10.00	1	
54	Bemidji, MN Industrial Park	Distribution		69.00	13.10		7.50	1	
55	Bottineau, ND Downtown	Distribution		41.60	12.50		10.00	3	
56	Bottineau, ND South	Distribution		43.80	13.10		10.00	1	
57	Casselton, ND	Distribution		43.80	7.60		10.00	1	
58	Casselton, ND 115 Ethanol plant	Distribution		115.00	12.50		66.00	2	
59	Cass Lake, MN 620349	Distribution		115.00	13.00		10.00	1	
60	Clearbrook, MN Pipeline	Distribution		115.00	4.16		20.00	2	
61	Cooperstown, ND	Distribution		43.80	13.10		10.00	1	
62	Crookston, MN Parkview	Distribution		43.80	13.10		10.00	1	
63	Crookston, MN South Main	Distribution		41.60	12.50		25.00	2	
64	Dawson, Mn Dawson Mills	Distribution		115.00	13.10		10.00	1	
65	Devils Lake, ND Downtown	Distribution		43.80	4.40		10.00	1	
66	Enderlin, ND	Distribution		115.00	13.10		14.00	1	
67	Fairmount, ND	Distribution		115.00	12.50		10.00	3	
68	Fergus Falls, MN Edgetown	Distribution		115.00	13.10		20.00	1	
69	Fergus Falls, MN Hoot Lake	Distribution		115.00	14.40		7.50	1	
70	Fergus Falls, MN South East	Distribution		115.00	13.10		37.30	1	
71	Gwinner, ND	Distribution		115.00	12.50		20.00	2	
72	Harvey, ND Northwest	Distribution		115.00	13.10		14.00	1	
73	Itasca, MN Minnesota Pipeline	Distribution		115.00	4.40		10.00	1	
74	Jamestown, ND Downtown	Distribution		115.00	12.50		54.80	2	
75	Jamestown, ND North	Distribution		115.00	13.10		10.00	1	
76	Jamestown, ND Potato	Distribution		115.00	13.10		10.00	1	
77	Jamestown, ND Southwest	Distribution		43.80	13.10		10.00	1	
78	Lake Norden, SD Dairy	Distribution		43.80	4.40		3.80	1	
79	Lake Norden, SD	Distribution		115.00	12.50		93.30	2	
80	Lisbon, ND Town	Distribution		115.00	12.10		14.00	1	
81	Mahnomen, MN	Distribution		115.00	13.10		10.00	1	
82	Milbank, SD Northwest	Distribution		41.60	12.50		63.00	3	
83	Milbank, SD South	Distribution		43.80	13.10		22.40	1	
84	Morris, MN Northeast	Distribution		43.80	13.10		1.00	1	
85	Morris, MN South	Distribution		115.00	12.50		10.00	3	
86	Oakes, ND North	Distribution		41.60	12.50		10.00	3	
87	Parkers Prairie	Distribution		43.80	13.10		12.50	1	
88	Pelican Rapids, MN Turkey Plant	Distribution		115.00	13.10		12.50	1	
89	Perham, MN	Distribution		115.00	12.50		13.00	2	
90	Rosholt, SD	Distribution		43.80	13.10		11.20	1	
91	Rugby, ND Northwest	Distribution		43.80	13.10		14.00	1	
92	Spiritwood, ND	Distribution		115.00	12.50		14.00	1	
93	Wahpeton Inventory	Distribution		115.00	12.50				1
94	Wahpeton Inventory	Distribution		115.00	4.16				1
95	Wahpeton Inventory	Distribution		41.60	4.16				1
96	Wahpeton Inventory	Distribution		41.60	12.50				1
97	Wahpeton, ND North 115 kv - 63230	Distribution		115.00	12.50		24.00	2	
98	Wahpeton, ND Northwest	Distribution		41.60	12.50		22.40	2	
99	Wheaton, MN South	Distribution		115.00	13.10		14.00	1	
100	TotalDistributionSubstationMember						891	65	4
101	TotalTransmissionSubstationMember						4,753	63	4
102	Total						5,644	128	8

Conversion Apparatus and Special Equipment

Line No.	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
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Conversion Apparatus and Special Equipment

Line No.	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
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102		0	0

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

[\(a\)](#) Concept: SubstationNameAndLocation

Joint ownership, Otter Tail Power Company, 53.9%; Northwestern Public Service Company, 23%; Montana-Dakota Utilities Company, 22.7%. Expenses are shared on ownership percent basis. Accounts affected are regular accounts applicable to substations. None of the owners are associated companies. Columns C, D and E are reported in KVA.

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Construction work in progress	Otter Tail Corporation	107	44,852
3	Expenditures for certain civic, political & relat	Otter Tail Corporation	426.4	22,272
4	Dividends declared - common stock	Otter Tail Corporation	438	58,385,674
5	^{(g)(7)} Corporate allocated A&G expense	Otter Tail Corporation	^(g) See Note	14,019,791
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Printing, design & mailing services	Otter Tail Corporation	417	13,770
22	Other deductions	Otter Tail Corporation	426.5	302,658
23	Printing, design & mailing services	TO Plastics	417	1,104
24	Printing, design & mailing services	BTD Manufacturing	417	10,538
42				

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

Corporate Allocated A&G expenses are allocated in accordance with Otter Tail Corporation's Corporate Cost Allocation Manual as provided by the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, and the South Dakota Public Utilities Commission.

(b) Concept: DescriptionOfNonPowerGoodOrService

Corporate Allocated A&G expenses are allocated in accordance with Otter Tail Corporation's Corporate Cost Allocation Manual as provided by the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, and the South Dakota Public Utilities Commission.

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

The following accounts were charged:

Account	Amount (\$)
500.0	5,779
506.0	3,947
908.0	7,098
920.0	5,661,162
921.0	5,400,729
923.0	1,520,852
924.0	19,172
925.0	222,852
926.0	23,372
928.0	8,416
930.1	6,131
930.2	857,567
931.0	126,160
935.0	156,555
	14,019,791

[PROTECTED DATA BEGINS...

Case No. PU-24-213

PU-24-213_2023-07-31_OTP SLGS Assessment Part 4 of 5_PUBLIC

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in its Entirety

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[PROTECTED DATA BEGINS...

Case No. PU-24-213

PU-24-213_2023-07-31_OTP EDR Assessment Part 5 of 5_PUBLIC

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