

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)



June 25, 2025

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 2024 Annual Report
Caser No. PU-25-193**

Dear Mr. Kahl:

Enclosed is Otter Tail Power Company's (Otter Tail Power's) 2024 Annual Report for North Dakota. As in past years, I am enclosing a copy of Otter Tail Corporation's 2024 Annual Report to Shareholders and SEC Form 10-K for Otter Tail Corporation and Otter Tail Power's 2024 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 Power's current base rate recoveries as well as recoveries through Otter Tail Power'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 Power's actual 2024 earnings reflected a return on equity (ROE) of 9.61 percent. As shown on page 5 of the attached report, Otter Tail Power's normalized 2024 results reflected a 9.96 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 2024 and a Trade Secret report on the Economic Development Rider Rate Schedule Section 14.13 (EDR) for the calendar year 2024. 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**.

4 PU-25-193 Filed 06/25/2025 Pages: 340
2024 Annual Report, Shareholders Report, and
FERC Financial Report for North Dakota - Redacted

Otter Tail Power Company
Christy Petersen, Mgr Reg Acct Reg Eco

If you have questions on the information provided, do not hesitate to contact me at (218) 739-8541 or cpetersen@otpc.com.

Sincerely,

/s/ Christy Petersen
Christy Petersen
Manager, Regulatory Accounting
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, 2024

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Otter Tail Power Company
2024 North Dakota Annual Report

Operating Statement - With All Riders, Un-Normalized

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	2024 Total Company	2024 North Dakota	ND Percent (B / A)	2023 North Dakota	Annual Change (B-D / D)
	Operating Revenues:					
1	Residential	\$ 131,774,557	\$ 63,439,802	48.14%	\$ 64,277,169	-1.30%
2	Small Commercial and Industrial	\$ 100,962,127	\$ 52,546,840	52.05%	\$ 50,493,353	4.07%
3	Large Commercial and Industrial	\$ 213,149,534	\$ 76,482,669	35.88%	\$ 71,815,944	6.50%
4	Other Retail	\$ 7,740,176	\$ 3,567,330	46.09%	\$ 3,195,321	11.64%
5	Total Retail Revenue	\$ 453,626,394	\$ 196,036,641	43.22%	\$ 189,781,787	3.30%
6	Other Electric Revenue	\$ 70,918,599	\$ 16,857,822	23.77%	\$ 16,203,943	4.04%
7	Total Revenue	\$ 524,544,993	\$ 212,894,463	40.59%	\$ 205,985,730	3.35%
	Operating Expenses:					
8	Production Expenses	\$ 163,674,129	\$ 69,330,206	42.36%	\$ 74,680,891	-7.16%
9	Transmission Expenses	\$ 36,452,533	\$ 14,448,570	39.64%	\$ 13,604,159	6.21%
10	Distribution Expenses	\$ 19,319,587	\$ 8,885,801	45.99%	\$ 9,017,670	-1.46%
11	Customer Accounting Expenses	\$ 12,413,942	\$ 5,369,477	43.25%	\$ 6,459,624	-16.88%
12	Customer Service and Information Expenses	\$ 11,083,422	\$ 1,116,625	10.07%	\$ 1,190,260	-6.19%
13	Sales Expenses	\$ 250,510	\$ 103,453	41.30%	\$ 83,182	24.37%
14	Administration and General Expenses	\$ 50,222,146	\$ 19,872,242	39.57%	\$ 19,432,122	2.26%
15	Charitable Contributions	\$ -	\$ -	N/A	\$ -	N/A
16	Depreciation Expense	\$ 81,164,542	\$ 32,058,053	39.50%	\$ 28,654,558	11.88%
17	General Taxes	\$ 15,653,729	\$ 5,806,971	37.10%	\$ 6,053,596	-4.07%
18	Total Operating Expenses	\$ 390,234,540	\$ 156,991,398	40.23%	\$ 159,176,062	-1.37%
19	Net Operating Income Before Income Taxes	\$ 134,310,452	\$ 55,903,065	41.62%	\$ 46,809,668	19.43%
	Income Tax Expense:					
20	Investment Tax Credit	\$ (8,421,455)	\$ (2,561,879)	30.42%	\$ (2,231,288)	14.82%
21	Deferred Income Taxes	\$ 18,165,145	\$ 6,102,333	33.59%	\$ 5,017,141	21.63%
22	Income Taxes	\$ 3,340,947	\$ 2,881,129	86.24%	\$ 2,345,029	22.86%
23	Total Income Tax Expense	\$ 13,084,637	\$ 6,421,583	49.08%	\$ 5,130,882	25.16%
24	Net Regulated Earnings	\$ 121,225,816	\$ 49,481,482	40.82%	\$ 41,678,786	18.72%

Otter Tail Power Company
2024 North Dakota Annual Report

Rate Base - With All Riders, Un-Normalized

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	2024 Total Company	2024 North Dakota	ND % (B / A)	2023 North Dakota	Annual Change (B-D / D)
1	Plant in Service	\$ 3,033,177,782	\$ 1,171,013,302	38.61%	\$ 1,084,654,218	7.96%
2	Net Capitalized Items - Big Stone Plant			0.00%		0.00%
3	Accumulated Depreciation	\$ (1,033,579,850)	\$ (430,300,119)	41.63%	\$ (406,873,524)	5.76%
4	Net Plant in Service	\$ 1,999,597,932	\$ 740,713,183	37.04%	\$ 677,780,694	9.29%
5	Plant Held for Future Use	\$ 6,019	\$ 2,487	41.32%	\$ 4,698	-47.06%
6	Construction Work in Progress	\$ 6,673,724	\$ 2,911,109	43.62%	\$ 3,835,086	-24.09%
7	Materials and Supplies	\$ 45,149,357	\$ 19,379,813	42.92%	\$ 15,252,169	27.06%
8	Fuel Stocks	\$ 11,674,937	\$ 4,753,972	40.72%	\$ 4,747,612	0.13%
9	Prepayments	\$ 73,545,692	\$ 27,243,609	37.04%	\$ 20,682,496	31.72%
10	Customer Advances	\$ (2,172,698)	\$ (804,835)	37.04%	\$ (649,435)	23.93%
11	Cash Working Capital	\$ 4,384,612	\$ 2,279,167	51.98%	\$ 2,240,644	1.72%
12	Accumulated Deferred Income Taxes	\$ (307,556,835)	\$ (117,000,576)	38.04%	\$ (106,785,515)	9.57%
13	Total Average Rate Base	\$ 1,831,302,740	\$ 679,477,929	37.10%	\$ 617,108,449	10.11%
ACTUAL						
14	Rate of Return on Average Rate Base (page 1, Line 24 /line 13)	6.62%	7.28%			
15	Less: Weighted Cost of Ltd (Page 3, line 1 (D))	2.13%	2.13%			
16	Weighted Cost of Pref. Stock (Page 3 line 2 (D))	0.00%	0.00%			
17	Weighted Return on Equity	4.48%	5.15%			
18	% of Equity to Capital Structure (Page 3, line 3 (B))	53.54%	53.54%			
19	Return on Equity (Page 3, line 3 (C))	8.37%	9.61%			

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

		(A)	(B)	(C)	(D)
Line No.	Description	2024 Total	Ratio	Cost	Weighted Cost
1	Long Term Debt	\$ 872,931,733	46.46%	4.60%	2.13%
2	Preferred Equity	\$ -	0.00%	0.00%	0.00%
3	Common Equity	\$ 1,006,148,718	53.54%	9.61%	5.15%
4	Total	\$ 1,879,080,451	100.00%		7.28%

Otter Tail Power Company
2024 North Dakota Annual Report

Operating Statement - With All Riders, Normalized

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	2024 Total Company	2024 North Dakota	N. D. % (B / A)	2023 North Dakota	Annual Change (B-D / D)
	Operating Revenues:					
1	Residential	\$ 134,603,549	\$ 66,249,805	49.22%	\$ 63,262,759	4.72%
2	Small Commercial and Industrial	\$ 101,252,606	\$ 53,420,066	52.76%	\$ 50,164,073	6.49%
3	Large Commercial and Industrial	\$ 213,853,159	\$ 76,643,504	35.84%	\$ 71,683,668	6.92%
4	Other Retail	\$ 7,773,508	\$ 3,579,694	46.05%	\$ 3,185,370	12.38%
5	Total Retail Revenue	\$ 457,482,823	\$ 199,893,070	43.69%	\$ 188,295,871	6.16%
6	Other Electric Revenue	\$ 68,327,836	\$ 15,758,460	23.06%	\$ 16,203,943	-2.75%
7	Total Revenue	\$ 525,810,659	\$ 215,651,530	41.01%	\$ 204,499,814	5.45%
	Operating Expenses:					
8	Production Expenses	\$ 166,182,728	\$ 70,411,631	42.37%	\$ 74,764,271	-5.82%
9	Transmission Expenses	\$ 36,452,533	\$ 14,448,570	39.64%	\$ 13,604,159	6.21%
10	Distribution Expenses	\$ 19,319,587	\$ 8,885,801	45.99%	\$ 9,017,670	-1.46%
11	Customer Accounting Expenses	\$ 12,413,942	\$ 5,369,477	43.25%	\$ 6,459,624	-16.88%
12	Customer Service and Information Expenses	\$ 11,083,422	\$ 1,116,625	10.07%	\$ 1,190,260	-6.19%
13	Sales Expenses	\$ 250,510	\$ 103,453	41.30%	\$ 83,182	24.37%
14	Administration and General Expenses	\$ 50,222,146	\$ 19,872,242	39.57%	\$ 19,432,122	2.26%
15	Charitable Contributions	\$ -	\$ -	N/A	\$ -	N/A
16	Depreciation Expense	\$ 81,164,542	\$ 32,058,053	39.50%	\$ 28,654,558	11.88%
17	General Taxes	\$ 15,653,729	\$ 5,806,971	37.10%	\$ 6,053,596	-4.07%
18	Total Operating Expenses	\$ 392,743,139	\$ 158,072,823	40.25%	\$ 159,259,442	-0.75%
19	Net Operating Income Before Income Taxes	\$ 133,067,519	\$ 57,578,707	43.27%	\$ 45,240,372	27.27%
	Income Tax Expense:					
20	Investment Tax Credit	\$ (8,421,455)	\$ (2,561,879)	30.42%	\$ (2,231,288)	14.82%
21	Deferred Income Taxes	\$ 18,165,145	\$ 6,102,333	33.59%	\$ 5,017,141	21.63%
22	Income Taxes	\$ 3,324,819	\$ 3,290,623	98.97%	\$ 1,961,365	67.77%
23	Total Income Tax Expense	\$ 13,068,509	\$ 6,831,077	52.27%	\$ 4,747,218	43.90%
24	Net Regulated Earnings	\$ 119,999,010	\$ 50,747,629	42.29%	\$ 40,493,154	25.32%

Otter Tail Power Company
2024 North Dakota Annual Report

Rate Base - With All Riders, Normalized

		(A)	(B)	(C)	(D)	(E)
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5	Plant Held for Future Use	\$ 6,019	\$ 2,487	41.32%	\$ 4,698	-47.06%
6	Construction Work in Progress	\$ 6,673,724	\$ 2,911,109	43.62%	\$ 3,835,086	-24.09%
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8	Fuel Stocks	\$ 11,674,937	\$ 4,753,972	40.72%	\$ 4,747,612	0.13%
9	Prepayments	\$ 73,545,692	\$ 27,243,609	37.04%	\$ 20,682,496	31.72%
10	Customer Advances	\$ (2,172,698)	\$ (804,835)	37.04%	\$ (649,435)	23.93%
11	Cash Working Capital	\$ 4,306,887	\$ 2,172,588	50.44%	\$ 2,375,299	-8.53%
12	Accumulated Deferred Income Taxes	\$ (307,559,835)	\$ (117,000,576)	38.04%	\$ (106,785,515)	9.57%
13	Total Average Rate Base	\$ 1,831,222,015	\$ 679,371,350	37.10%	\$ 617,243,104	10.07%
ACTUAL						
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Otter Tail Power Company
2024 North Dakota Annual Report

Average Weighted Cost of Capital - With All Riders, Normalized

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Line No.	Description	2024 Total	Ratio	Cost	Weighted Cost
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2	Preferred Equity	\$ -	0.00%	0.00%	0.00%
3	Common Equity	<u>\$ 1,006,148,718</u>	<u>53.54%</u>	10.10%	<u>5.41%</u>
4	Total	\$ 1,879,080,451	100.00%		7.54%

Otter Tail Power Company
2024 North Dakota Annual Report

Miscellaneous

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
Line No.	Total Description	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
	Customer Related (ND):											
	Year End # of Customers (1)											
1	Residential	45,463	45,431	45,535	45,584	45,614	45,620	45,862	45,882	45,743	45,689	45,379
2	Commercial	12,457	12,481	12,448	12,481	12,430	12,395	11,465	11,439	11,385	11,333	11,286
3	Industrial	287	289	285	283	278	277	980	979	978	984	947
4	Other	882	882	885	888	890	889	497	499	503	509	504
5	Total Customers	59,089	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	554,454,423	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	487,265,045	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	1,372,641,305	1,365,347,468	1,122,524,727	607,703,011	596,367,789	653,782,339	861,510,082	854,040,398	856,344,193	852,769,327	899,948,129
9	Other	24,731,824	25,335,667	27,194,689	26,994,553	29,522,372	29,278,133	29,467,197	29,625,196	29,362,956	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	17,087,461	(28,187,360)	*****	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	17,087,461	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)	141.7	110.8	118.6	79.0	91.3	128.2	85.3	86.5	110.5	100.6	74.2
14	SAIFI (frequency)	1.2	1.5	1.6	1.2	1.3	1.5	1.3	1.4	1.7	1.7	1.2
15	CAIDI (duration)	119.0	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-25-193

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

July 26, 2025

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Otter Tail Power Company 2024 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 VertexOne, formerly Accelerated Innovations, to develop an online platform that provides customers enhanced functionality in the areas of bill payment, usage information, and outage and load management 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 fully integrated with our Outage Management System (OMS), Customer Information System, Paymentus payment provider, as well as MDMS/AMI and provides the most comprehensive information to the customer having these other systems in place.

Implementation began in April 2022 and the project went live in August 2023. This platform will continually be enhanced with further improvements, such as an Outage Center and Landlord portal area, to enhance the customer experience.

Advanced Metering Infrastructure (AMI)

Otter Tail Power continues to work toward completion of 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 and vendor product deliveries. An AMI pilot of 500 meters occurred in December 2023. Full meter deployment started in mid-February 2024 and meter installations continued throughout the year with around 158,000 new AMI meters installed by the end of 2024. Allegiant Utility Services, Otter Tail Power's meter installation contractor, completed their contracted portion of the installations in 2024, which represented approximately 91 percent of the total meter installations. Otter Tail Power continues to install new AMI meters associated with complex rates, complexity of metering configurations, and heightened impact to customer processes. Allowing Otter Tail Power staff to manage these meter exchanges has allowed for a more coordinated exchange process for the customer group, which includes larger commercial and industrial load. Otter Tail Power plans to complete the AMI project in 2025.

Demand Response – Advanced Load Management (ALM)

The Demand Response replacement or now known as Advanced Load Management (ALM), project began development in early 2021. In the Fall of 2021, Otter Tail Power retained Katama Technologies as a consultant to assist in the Request for Proposal process. Otter Tail Power's Request for Proposals was released in the Fall of 2022, receiving six responses. Otter Tail Power selected: Landis+Gyr (L+G) and Open Access Technology International (OATI).

Otter Tail Power signed contracts with L+G and OATI in the first quarter of 2025 with detailed system requirements and design starting in quarter two. Like Otter Tail Power's AMI project: ALM is a technology project with complex software application integrations along with a hardware upgrade for consumers that have elected load control rates. Field deployment work is scheduled to begin in 2026 with a project completion targeting mid-2028.

ALM is included in Otter Tail Power's Innovative Distributed Energy Automation (IDEA) application for the Federal DOE GRIP Topic Area 2 – Smart Grid Grants. The IDEA application has been selected to move forward with negotiations. Otter Tail Power is currently engaged with the DOE on negotiations and trying to determine the impacts of the changing grant requirements.

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 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.

In June 2025, Otter Tail successfully activated the integration between our AMI and OMS. Although this integration is still new, we have already seen several impactful benefits. We can now restore outages before customers report them, address recurring issues like loose connections more proactively, and deploy field personnel with greater efficiency.

Looking ahead, we are enhancing customer communication through CEP by developing a new feature called the Outage Center. This tool will trigger real-time notifications when customers log into CEP, ensuring they receive timely and relevant updates during outages.

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.

2024



Annual Report





Otter Tail Power Company
Electric utility
Headquarters: Fergus Falls, MN
Founded: 1907
Full-time employees: 798
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, commercial and talent excellence



MANUFACTURING PLATFORM

BTD Manufacturing, Inc.

Metal fabricator
Headquarters: Detroit Lakes, MN
Acquired: 1995
Full-time employees: 960
www.btdmfg.com



T.O. Plastics, Inc.

Custom plastic products manufacturer
Headquarters: Clearwater, MN
Acquired: 2001
Full-time employees: 162
www.toplastics.com



Northern Pipe Products, Inc.

PVC pipe manufacturer
Headquarters: Fargo, ND
Acquired: 1995
Full-time employees: 93
www.northernpipe.com



Vinyltech Corporation

PVC pipe manufacturer
Headquarters: Phoenix, AZ
Acquired: 2000
Full-time employees: 82
www.vtpipe.com



	2024	2023	Percent Change
CONSOLIDATED OPERATIONS (\$ in thousands, except per share amounts)			
Operating Revenues	\$ 1,330,548	\$ 1,349,166	(1.4)
Net Income	\$ 301,662	\$ 294,191	2.5
Diluted Earnings per Share	\$ 7.17	\$ 7.00	2.4
Dividends per Common Share	\$ 1.87	\$ 1.75	6.9
Return on Average Common Equity	19.3%	22.1%	(12.7)
Book Value per Common Share	\$ 39.89	\$ 34.60	15.3
Cash Flow from Operating Activities	\$ 452,731	\$ 404,499	11.9
Number of Common Shares Outstanding	41,827,967	41,710,521	0.3
Number of Common Shareholders	10,245	10,650	(3.8)
Closing Stock Price	\$ 73.84	\$ 84.97	(13.1)
Total Return (share price appreciation plus dividends)	(10.9)%	47.7%	n/m
Total Market Value of Common Stock	\$ 3,088,577	\$ 3,544,143	(12.9)
ELECTRIC PLATFORM			
Operating Revenues	\$ 524,515	\$ 528,359	(0.7)
Total Retail Electric Sales (MWH)	5,681,268	5,772,215	(1.6)
Net Income	\$ 90,963	\$ 84,424	7.7
Customers	133,971	133,747	0.2
Total Assets	\$ 2,785,522	\$ 2,533,831	9.9
Capital Expenditures	\$ 301,454	\$ 240,695	25.2
MANUFACTURING PLATFORM			
Operating Revenues	\$ 806,033	\$ 820,807	(1.8)
Net Income	\$ 214,428	\$ 209,202	2.5
Total Assets	\$ 440,488	\$ 415,522	6.0
Capital Expenditures	\$ 56,908	\$ 46,313	22.9

To our shareholders

CHARLES S. MACFARLANE
PRESIDENT AND CEO



Otter Tail Corporation remains committed to our mission—delivering value for our shareholders, customers and employees by building strong electric utility and manufacturing platforms. We aim to deliver above-average returns to our shareholders, reliable service, high-quality products and value for our customers and an environment of opportunity for our employees.

I am proud of how Otter Tail Corporation performed in 2024, delivering record annual earnings, and am grateful to our team members for their hard work, dedication to our mission and the ways in which they lived out our values each day.

STRONG FINANCIAL RESULTS

Otter Tail Corporation produced record earnings in 2024, generating diluted earnings per share of \$7.17, compared with \$7.00 in 2023. We achieved a consolidated return on equity of 19.3 percent on an equity ratio of 62.2 percent. We ended 2024 in a position of financial strength, with a solid balance sheet and ample liquidity to support future growth initiatives.

The completion of 2024 marked the 86th consecutive year we've paid dividends to our shareholders. In early 2025 we increased our dividend by 12.3 percent, producing an annual indicated dividend of \$2.10. We have performed very well over the last few years, and the double-digit increase to our dividend reflects our commitment to delivering shareholder value. Going forward, we expect our annual dividend increase to approximate our long-term earnings per share growth rate target.

For a fourth 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 66.9 percent over the five-year period ending September 30, 2024. 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.

EXECUTING OUR STRATEGY

ELECTRIC PLATFORM HIGHLIGHTS

Otter Tail Power Company, our regulated electric utility, produced \$91.0 million of earnings in 2024 and continues to perform well, converting our rate base growth into earnings growth at approximately a 1:1 ratio. We executed on our key regulatory priorities and delivered against our significant rate base growth plan. We remain committed to providing safe, reliable and increasingly clean electric service to our customers while maintaining some of the lowest electric rates in the nation.

Our Advanced Metering Infrastructure project, with a total investment of \$60 million, is progressing well and we plan to finish upgrading more than 170,000 electric meters in 2025. We look forward to leveraging the additional features these meters will provide to better

serve our customers through outage response and visibility into their energy use that can help them save money.

Upgrades and refurbishments to four of our owned wind energy centers remain on schedule. We repowered the Langdon Wind Energy Center in late 2024 and plan to finish the equipment upgrades at the Ashtabula, Ashtabula III and Luverne Wind Energy Centers by the end of 2025. Despite the approximately \$230 million capital investment associated with this project, we continue to expect this repowering to lower customer bills through the use of available tax credits and the increased energy output provided.

We continued to make significant progress on our Midcontinent Independent System Operator (MISO) Long-Range Transmission Planning Tranche 1 projects throughout 2024. We secured various required regulatory approvals for the projects and continued our public outreach. The total capital investment associated with this portfolio of projects is estimated to be \$475 million, and we expect to complete it in 2032.

The Minnesota Public Utilities Commission approved our Integrated Resource Plan in May. The decision authorized the addition of 200 to 300 megawatts of solar generation by 2027, 150 to 200 megawatts of wind generation and 20 to 75 megawatts of battery storage by 2029. We also received approval to designate the Minnesota portion of Coyote Station as an emergency-only resource starting as early as 2026, retaining the reliability benefits from the coal facility while simultaneously reducing its output and emissions.

We announced plans to add two solar facilities, totaling up to 345 megawatts, to our energy generation fleet in December, subject to certain regulatory approvals. Solway Solar is a 50 megawatt solar generation facility we plan to build in Minnesota. Depending on the timing of project approvals, we anticipate this facility to be fully operational in 2026. Abercrombie Solar is a 295 megawatt solar generation facility under development in North Dakota, and we currently expect this facility to be complete in 2028.

In December, the North Dakota Public Service Commission approved our fully settled general rate case. The outcome of the case provided for a net annual revenue requirement increase of 6.2 percent premised on a return on equity of 10.1 percent and an equity layer of 53.5 percent. Even with this approved increase, our electric service rates remain among the lowest in the nation.

MANUFACTURING PLATFORM HIGHLIGHTS

Northern Pipe Products and Vinyltech, our two PVC pipe manufacturing companies comprising our Plastics segment, produced record earnings in 2024 totaling \$200.7 million. We continue to benefit from improved end market demand and customers' sales volume growth.

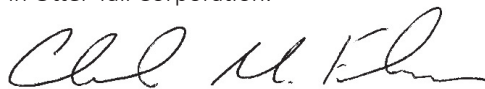
We completed the first phase of our Vinyltech expansion project in the fourth quarter on time and on budget, providing a new facility in Phoenix, Arizona, for our team members and increasing our resin and pipe storage. The first phase also added a line capable of producing large diameter PVC pipe, increasing our Plastics segment production capacity by approximately 7 percent. We look forward to leveraging this new capability at Vinyltech to better serve our customers in the southwest market.

Our Manufacturing segment, comprised of BTD Manufacturing, our contract metal fabricator, and T.O. Plastics, our custom plastic products manufacturer, generated \$13.7 million of earnings in 2024. BTD Manufacturing and T.O. Plastics navigated softened end market demand in 2024, especially in the second half of the year. The end markets most impacted were recreational vehicle, agriculture, construction, lawn and garden and horticulture. We took action to mitigate the impact of lower sales volumes on earnings while ensuring we are still well positioned once demand improves. Despite the down-cycle, this segment continues to produce incremental cash to fund future growth and the long-term fundamentals remain intact.

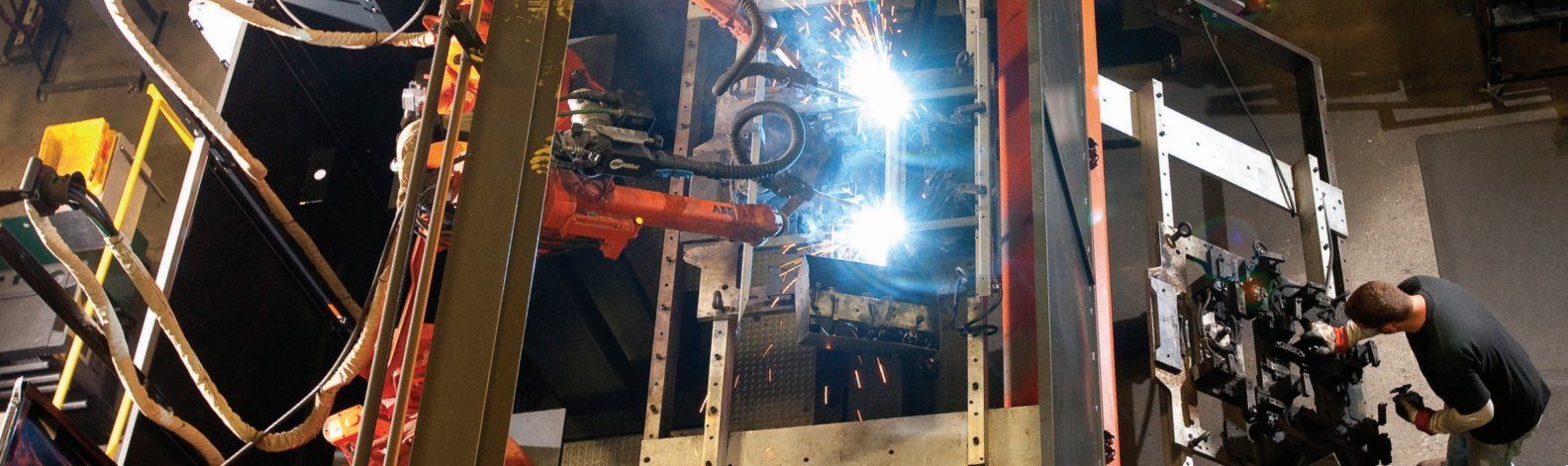
BTD Manufacturing's expansion project at our Dawsonville, Georgia location is progressing well. Many of our customers are expanding in the southeast market and this project positions us well to support this growth. We are currently occupying the new space and plan to bring the additional manufacturing capacity online in the first quarter of 2025, which is expected to unlock up to \$35 million in incremental annual sales.

TARGETING GROWTH

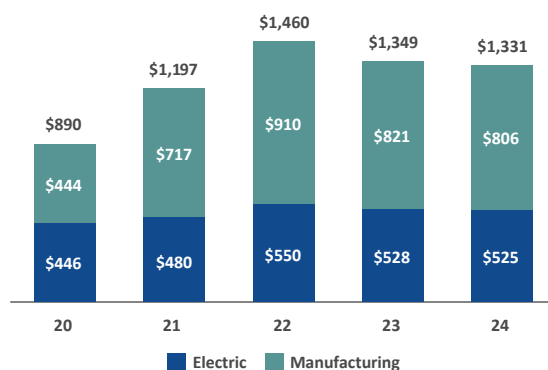
We updated our five-year capital spending plan and revised our long-term financial targets. Otter Tail Power's updated five-year capital spending plan totals \$1.4 billion and is expected to produce a rate base compounded annual growth rate of 9.0 percent. We also increased our consolidated long-term earnings per share growth rate target to 6 to 8 percent from 5 to 7 percent, increasing our total shareholder return target to 9 to 11 percent. We are positioned well to deliver on our revised financial targets over the long term and will continue to strive for operational, commercial and talent excellence. Thank you, again, to our employees for your collective efforts and to our customers and shareholders for your continued confidence in Otter Tail Corporation.



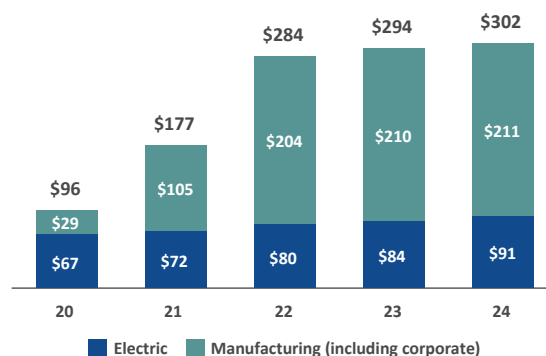
Charles S. MacFarlane
President and Chief Executive Officer



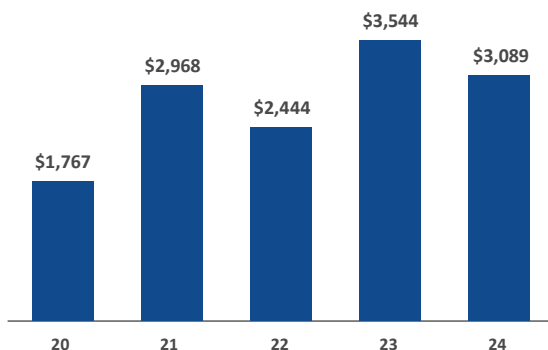
Revenue by Platform (millions)



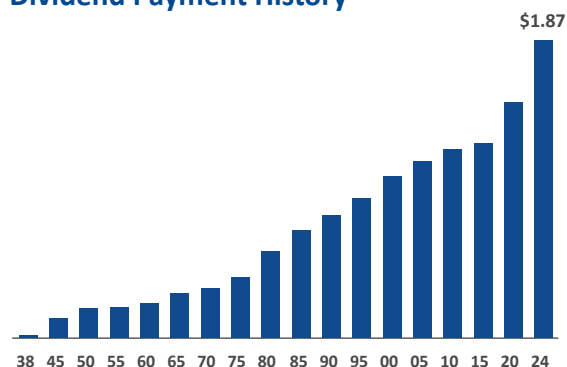
Net Income by Platform (millions)



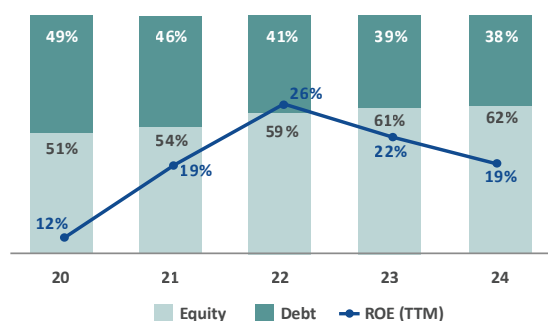
Market Capitalization (millions)



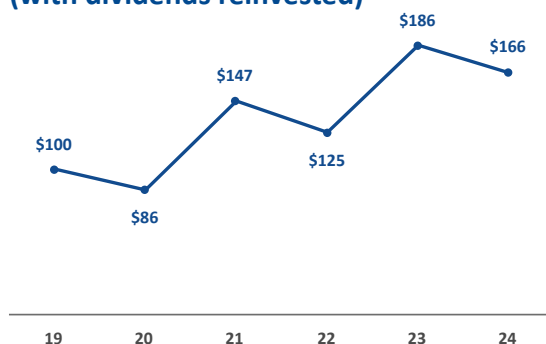
Dividend Payment History



Capital Structure and Return on Equity



Growth of \$100 Investment in Otter Tail Common Stock made December 31, 2019 (with dividends reinvested)



SELECTED COMMON SHARE DATA	2024	2023	2022	2021	2020	2019
Market Price						
High	\$ 100.84	\$ 92.74	\$ 82.46	\$ 71.71	\$ 56.90	\$ 57.74
Low	\$ 73.26	\$ 57.29	\$ 52.60	\$ 39.35	\$ 30.95	\$ 45.94
Common Price/Earnings Ratio						
High	14.1	13.2	12.2	17.0	24.3	26.6
Low	10.2	8.2	7.8	9.3	13.2	21.2
Book Value per Common Share	\$ 39.89	\$ 34.60	\$ 29.24	\$ 23.84	\$ 21.00	\$ 19.46
SELECTED DATA AND RATIOS						
Interest Coverage Before Taxes	9.8x	8.4x	10.8x	6.5x	4.1x	4.1x
Effective Income Tax Rate	18%	19%	21%	17%	17%	17%
Return on Capitalization Including Short-Term Debt	12.8%	10.9%	15.6%	11.6%	7.6%	8.0%
Return on Average Common Equity ⁽¹⁾	19.3%	22.1%	25.6%	19.2%	11.6%	11.6%
Dividend Payout Ratio	26%	25%	24%	37%	63%	65%
Cash Realization ⁽²⁾	1.50	1.37	1.37	1.31	2.21	2.13
Capital Ratio						
Short-Term and Long-Term Debt	37.8%	38.6%	40.6%	46.3%	49.3%	47.1%
Common Equity	62.2%	61.4%	59.4%	53.7%	50.7%	52.9%
SELECTED ELECTRIC OPERATING DATA						
Revenues (thousands)						
Residential	\$ 133,408	\$ 135,570	\$ 143,888	\$ 135,361	\$ 127,260	\$ 131,988
Commercial and Industrial	311,968	312,551	318,494	262,408	254,951	267,125
Other Retail	7,838	7,719	7,918	7,715	7,311	7,365
Total Retail	453,214	455,840	470,300	405,484	389,522	406,478
Sales for Resale	11,077	12,459	18,539	17,936	4,857	5,007
Other Electric	60,224	60,060	60,860	56,901	51,751	47,612
Total Electric	\$ 524,515	\$ 528,359	\$ 549,699	\$ 480,321	\$ 446,130	\$ 459,097
Kilowatt-Hours Sold (thousands)						
Residential	1,174,545	1,252,627	1,309,249	1,241,951	1,266,232	1,303,317
Commercial and Industrial	4,450,461	4,450,183	4,224,190	3,489,342	3,446,743	3,598,002
Other	56,262	69,404	58,928	58,586	63,712	67,770
Total Retail	5,681,268	5,772,215	5,592,368	4,789,879	4,776,687	4,969,089
Sales for Resale	273,365	351,729	267,184	420,044	236,528	198,569
Total	5,954,633	6,123,944	5,859,552	5,209,923	5,013,215	5,167,658
Annual Retail Kilowatt-hour Sales Growth	(1.6)%	3.2%	16.8%	0.3%	(3.9)%	(0.2)%
Heating Degree Days ⁽³⁾	5,313	6,259	7,122	5,794	6,174	7,240
Cooling Degree Days ⁽⁴⁾	440	590	531	704	534	392
Average Revenue Per Kilowatt-hour						
Residential	11.38¢	10.82¢	10.99¢	10.90¢	10.05¢	10.13¢
Commercial and Industrial	7.03¢	7.02¢	7.54¢	7.52¢	7.40¢	7.42¢
All Retail	7.98¢	7.90¢	8.41¢	8.47¢	8.15¢	8.18¢
Customers						
Residential	104,367	104,151	103,950	103,835	103,658	103,328
Commercial and Industrial	27,714	27,709	27,578	27,582	27,468	27,348
Other	1,890	1,887	1,886	1,887	1,906	1,911
Total Electric Customers	133,971	133,747	133,414	133,304	133,032	132,587
Peak Demand and Net Generating Capability						
Peak Demand (kilowatts)	969,509	961,210	987,628	865,120	844,929	923,962
Owned Generation (kilowatts)						
Steam	415,900	405,300	406,200	406,800	548,100	548,700
Wind	350,400	350,400	288,000	288,000	288,000	138,000
Combustion Turbines	416,700	352,500	343,700	352,500	107,900	105,100
Solar	49,900	49,900	—	—	—	—
Hydro	1,000	2,600	2,500	2,600	2,500	2,800
Total Owned Generation	1,233,900	1,160,700	1,040,400	1,049,900	946,500	794,600

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.

Executive and Senior Leadership

CHARLES S. MACFARLANE

President and
Chief Executive Officer

TODD R. WAHLUND

Vice President and
Chief Financial Officer

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
Retired President and
Chief Investment Officer
Duff & Phelps Investment
Management Co.

JEANNE H. CRAIN ^{1,2}

President and
Chief Executive Officer
Bremer Financial
Corporation

JOHN D. ERICKSON

Advisor, ECJV Holding, LLC
Former President and
Chief Executive Officer
Otter Tail Corporation

STEVEN L. FRITZE ^{1,3}

Retired Chief Financial Officer
Ecolab Inc.

DR. KATHRYN O. JOHNSON ^{2,3}

Senior Geochemist
Barr Engineering

DR. MICHAEL E. LEBEAU ^{2,3}

System Vice President
Sanford Health

MARY E. LUDFORD ^{1,3}

Retired Chief Audit Executive
and Deputy Chief Security Officer
Exelon Corporation

CHARLES S. MACFARLANE

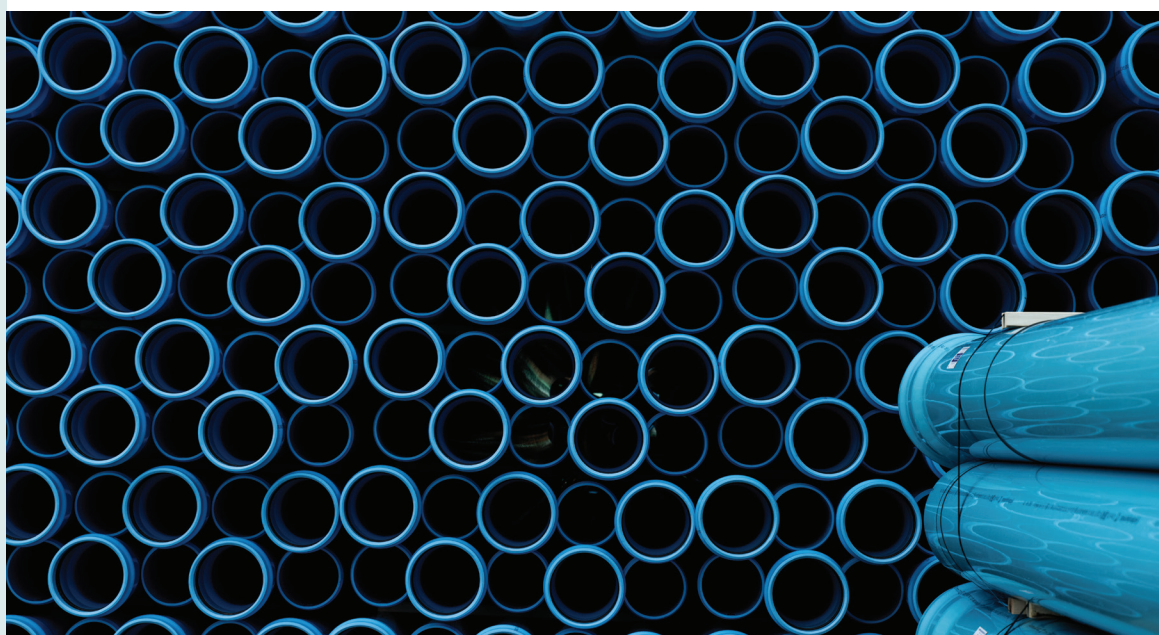
President and
Chief Executive Officer
Otter Tail Corporation

THOMAS J. WEBB ^{1,2}

Advisor
Retired Executive Vice President
and Chief Financial Officer
CMS Energy Corporation

Board Committees

1. Audit
2. Compensation and Human Capital Management
3. 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, 2024 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, 2024, the aggregate market value of common stock held by non-affiliates was **\$3,545,374,386**.Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **41,827,999 Common Shares (\$5 par value) as of January 31, 2025**.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive Proxy Statement for its 2025 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:

ADP	Advanced Determination of Prudence	kV	kiloVolt
AFUDC	Allowance for Funds Used During Construction	kW	kiloWatt
AME	Available Maximum Energy	kwh	kilowatt-hour
ARO	Asset Retirement Obligation	LSA	Lignite Sales Agreement
ARP	Alternative Revenue Program	MDT	Metering and Distribution Technology
ASC	Accounting Standards Codification	MISO	Midcontinent Independent System Operator
BSER	Best System of Emission Reduction	MPUC	Minnesota Public Utilities Commission
BTD	BTD Manufacturing, Inc.	MW	Megawatt
CCMC	Coyote Creek Mining Company, L.L.C.	NAV	Net Asset Value
CCR	Coal Combustion Residual	NDDEQ	North Dakota Department of Environmental Quality
CDD	Cooling Degree Day	NDPSC	North Dakota Public Service Commission
CIS	Center for Information Security	NERC	North American Electric Reliability Corporation
CO ₂	Carbon dioxide	Northern Pipe	Northern Pipe Products, Inc.
CODM	Chief Operating Decision Maker	NOx	Nitrogen Oxides
COSO	Committee of Sponsoring Organizations of the Treadway Commission	OTC	Otter Tail Corporation
DOE	U.S. Department of Energy	OTP	Otter Tail Power Company
DOJ	U.S. Department of Justice	PFAS	Polyfluoroalkyl substances
ECO	Energy Conservation and Optimization Rider	PIR	Phase-in Rider
EEI	Edison Electric Institute	PSLRA	Private Securities Litigation Reform Act of 1995
EEP	Energy Efficiency Plan	PTCs	Production tax credits
EPA	Environmental Protection Agency	PVC	Polyvinyl chloride
ERISA	Employee Retirement Income Security Act of 1974	RHR	Regional Haze Rule
ESSRP	Executive Survivor and Supplemental Retirement Plan	ROE	Return on equity
EUIC	Electric Utility Infrastructure Costs Rider	REC	Renewable Energy Certificate
FASB	Financial Accounting Standards Board	RRR	Renewable Resource Rider
FCA	Fuel Clause Adjustment	RTOs	Regional Transmission Organizations
FERC	Federal Energy Regulatory Commission	SDPUC	South Dakota Public Utilities Commission
FOB	Free on Board	SEC	Securities and Exchange Commission
GCR	Generation Cost Recovery Rider	SIP	State Implementation plan
GHG	Greenhouse Gas	SO ₂	Sulfur Dioxide
HDD	Heating Degree Day	SOFR	Secured Overnight Financing Rate
HDPE	High-Density Polyethylene	SPP	Southwest Power Pool
ICSP	Information and Cybersecurity Program	T.O. Plastics	T.O. Plastics, Inc.
IRP	Integrated Resource Plan	TCR	Transmission Cost Recovery Rider
IT	Information Technology	TSR	Total Shareholder Return
ITC	Investment Tax Credits	VIE	Variable Interest Entity
JTIQ	Joint Targeted Interconnection Queue	Vinyltech	Vinyltech Corporation

WHERE TO FIND MORE INFORMATION

We make available free of charge on 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) is a holding company which has strategically invested in a portfolio of diversified operations including 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 primary business since 1907, serves approximately 134,000 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

Our investment and growth strategy is focused on our electric utility as our foundational business, complemented by our investments in our Manufacturing and Plastics segments (collectively, our Manufacturing Platform). This strategic diversification allows us to maintain a moderate risk profile while driving growth through rate base investments in our Electric segment and organic growth opportunities in our Manufacturing Platform. This strategy and risk profile are designed to provide a more predictable earnings stream, to provide growth over long-term cycles, to produce returns above the utility industry average, to support investment grade credit ratings, and to provide for dividend payments to our shareholders.

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 6 to 8%, 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 6 to 8%. 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 recent investments within our Manufacturing and Plastics segments.

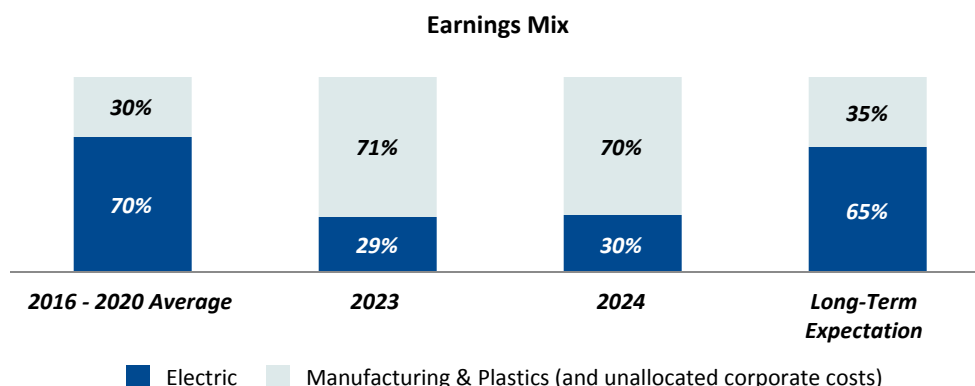
Since 2021, our earnings mix has diverged from our long-term target of 65% from our Electric segment and 35% from our Manufacturing Platform and our earnings growth rate has exceeded our long-term targeted growth rate primarily due to market conditions within the PVC pipe industry. These conditions have led to significant revenue, earnings and cash flow growth in our Plastics segment. Currently, we expect these industry conditions to gradually normalize through 2027. 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, 2024 and 2023 along with an historical average and long-term expectation are shown below:



HUMAN CAPITAL

Our employees are a critical resource for our business 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. We monitor various metrics and objectives associated with i) employee safety, ii) workforce stability, iii) management and workforce demographics, iv) leadership development and succession planning v) productivity, and vi) employee engagement. 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 2024 Total Recordable Incident Rate was 1.64, compared to 1.70 in 2023 and our Lost Time Incident Rate was 0.16 in 2024, compared to 0.53 in 2023.

Employee and Leadership Development, Succession Planning and Training Programs - We invest in training and professional development for 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.

Inclusive Workplace - 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.

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, 2024, we employed 2,133 full-time employees as shown in the table below:

<i>Segment/Organization</i>	<i>Employees</i>
Electric Segment	
OTP ⁽¹⁾	798
Manufacturing Segment	
BTD	960
T.O. Plastics	162
Segment Total	1,122
Plastics Segment	
Northern Pipe	93
Vinyltech	82
Segment Total	175
Corporate	38
Total	2,133

⁽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.

As of December 31, 2024, 371 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.

ELECTRIC

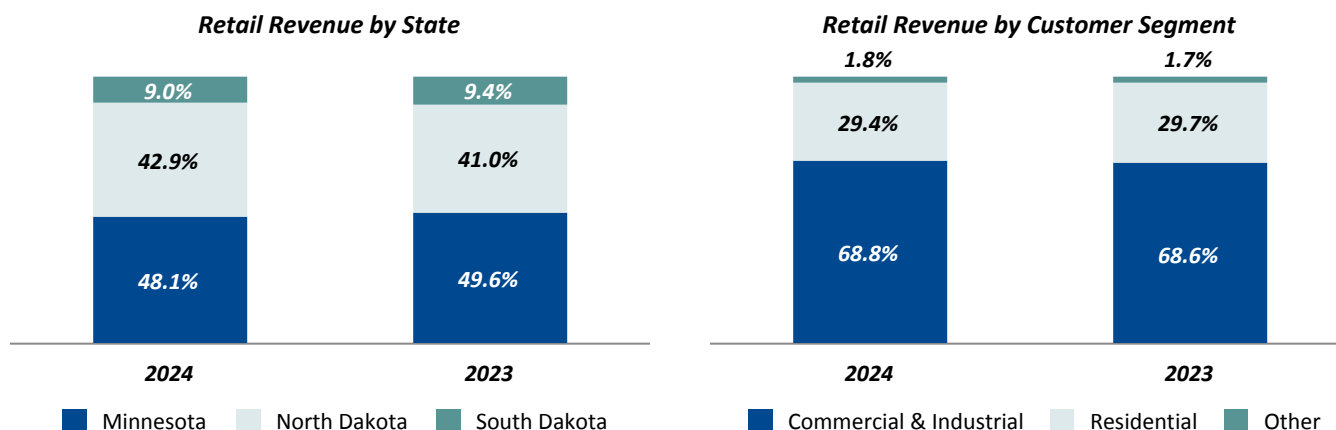
Contribution to Operating Revenues: 39% (2024), 39% (2023), 38% (2022)

OTP, headquartered in Fergus Falls, Minnesota, is a vertically integrated, regulated utility with generation, transmission and distribution facilities to serve its approximately 134,000 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 and in 2024 two customers combined accounted for 19% of segment operating revenues.

The following charts summarize our retail electric revenues by state and by customer segment for the years ended December 31, 2024 and 2023:



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, designed to meet specific, local needs. The adoption of distributed generation can be impacted by the availability of tax credits associated with the development and use of distributed energy. 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. In 2024, our summer residential rates were 16% below the regional average and 30% below the national average.

The following table presents our average retail rate per kilowatt-hour (kwh) by customer class and in total for the years ended December 31, 2024 and 2023:

<i>Revenue per kwh</i>	2024	2023
Residential	11.38 ¢	10.82 ¢
Commercial & Industrial	7.03 ¢	7.02 ¢
Total Retail	7.98 ¢	7.90 ¢

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, including the three states in our service territory, have laws which provide the incumbent transmission owner the right of first refusal to construct and own new transmission facilities. Future changes to the laws which provide for the right of first refusal could impact the competitive conditions related to the construction of 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 with wholesale market energy being utilized when it is determined to be beneficial to customers.

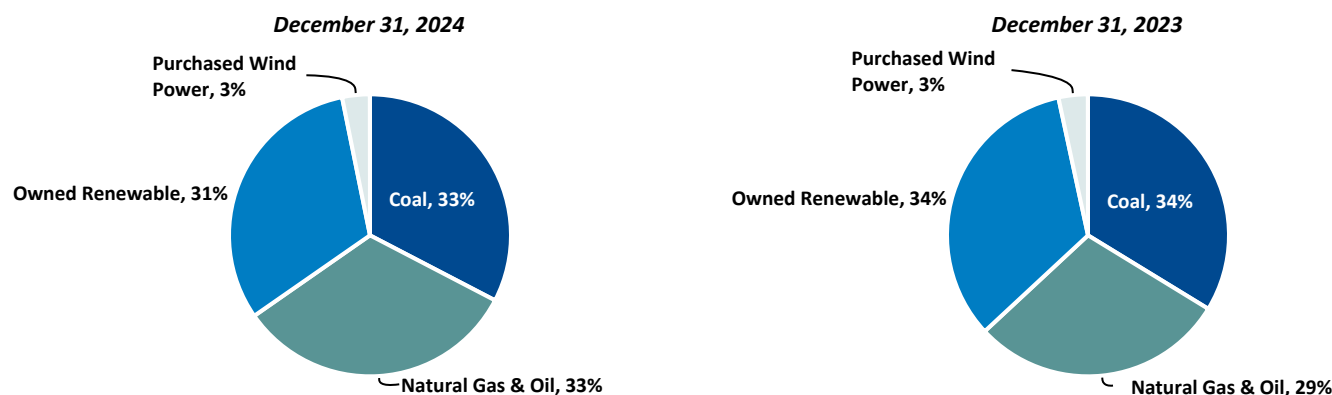
As of December 31, 2024, OTP's wholly or jointly owned plants and facilities, as well as in place power purchase agreements, and their dependable kilowatt (kW) capacity were:

	<i>Capacity / Purchased Power in kW</i>
Owned Generation:	
Baseload Plants	
Big Stone Plant ⁽¹⁾	264,700
Coyote Station ⁽²⁾	151,200
Total Baseload Plants	415,900
Combustion Turbine and Small Diesel Units	
Astoria Station	288,800
Solway	50,000
All Other	77,900
Total Combustion Turbine and Small Diesel Units	416,700
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 (rated at nameplate)	49,900
Hydroelectric Facilities	1,000
Total Owned Generation Capacity	1,233,900
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	1,274,400

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

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

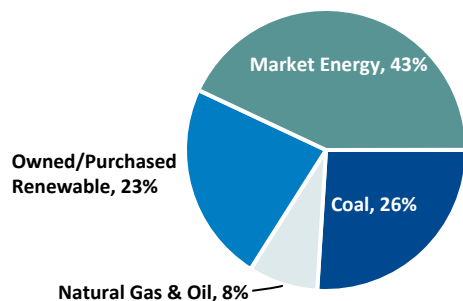
The following charts summarize the percentage of our generating capacity by source, including owned and jointly owned facilities and through power purchase arrangements, as of December 31, 2024 and 2023:



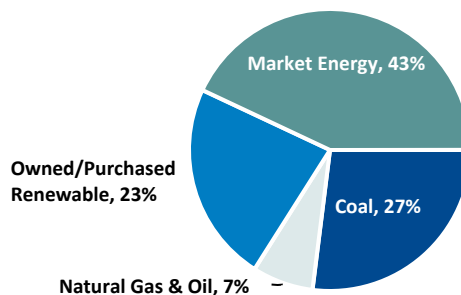
Under the Midcontinent Independent System Operator (MISO) requirements, OTP is required to provide sufficient capacity through wholly or jointly owned generating capacity or power purchase agreements to meet its monthly weather-normalized forecast demand, plus a reserve obligation. MISO operates under 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 9.0% and 33.9%, depending on the season.

The following charts summarize the percentage of retail kwh sold by source during the years ended December 31, 2024 and 2023:

Year Ended December 31, 2024



Year Ended December 31, 2023



Capacity Additions

As part of our investment plan to meet our future energy needs, the following projects are under development or construction:

Wind Energy Facility Upgrades consist 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 megawatts (MW) of generation. Our Langdon facility upgrades were completed in the fourth quarter of 2024 and we anticipate the remaining facilities will 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.

Solway Solar is a solar facility currently under development that is planned to be constructed adjacent to our existing Solway natural gas plant in northern Minnesota. The project is expected to add an additional 50 MW of generating capacity. We estimate the facility will be operational by the end of 2026 and OTP's capital investment is estimated to be \$100 million. The recovery of the costs of this project remains subject to regulatory approval.

Abercrombie Solar is solar facility currently under development in southeastern North Dakota. In October 2024, we entered into a purchase agreement to acquire the development assets of the project, including approximately 3,400 acres of land, interconnection agreements, state and local permits, and all other assets of the project. We anticipate we will close on the purchase of the development project in late 2025 or early 2026 and estimate the facility will be operational by the end of 2028. Once complete, the facility is expected to have a generating capacity of 295 MW. OTP's capital investment in the project is estimated to be \$450 million. The recovery of the costs of this project remains subject to regulatory approval.

ENERGY TRANSITION

OTP is 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**.

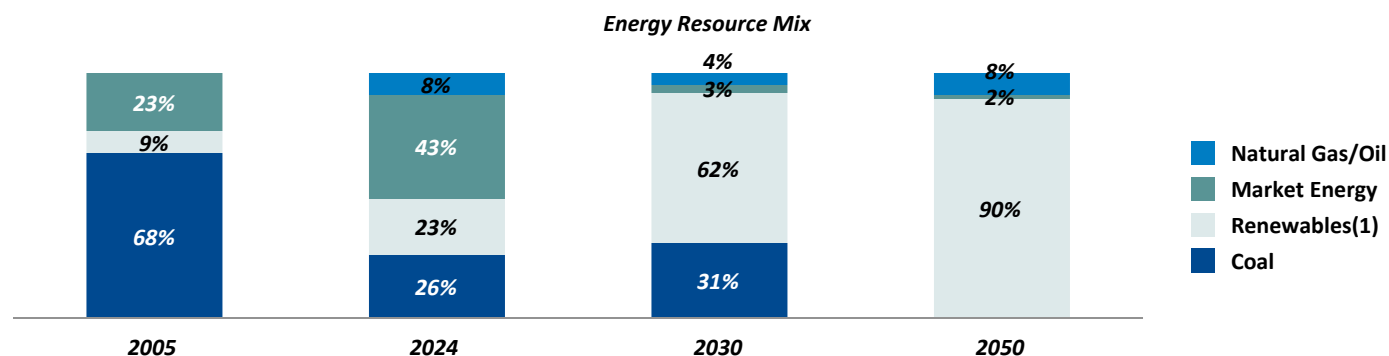
Reduce carbon emissions from owned generation resources **50% by 2030** from 2005 levels.

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

We have 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 adding the 49 MW Hoot Lake Solar facility to our resource mix, the investment in our wind energy facility upgrades, the commencement of development of the 50 MW Solway Solar and 295 MW Abercrombie Solar facilities, and sponsoring energy conservation programs.

From 2005 through 2024, we have reduced our carbon dioxide (CO₂) emissions approximately 40% 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 2024, 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. 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 2026 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, 2024, 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

MISO Tranche 1.0. In 2022, MISO approved several projects within the first tranche of its long-range transmission plan. Within the first tranche of projects, OTP will be a partial owner of two new 345 kV transmission projects. These projects will be developed and constructed over several years and OTP's total investment in these projects is estimated to be \$475 million.

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 and is expected to be completed in 2028.

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 and is expected to be completed in 2032.

MISO Tranche 2.1. In December 2024, MISO approved several projects within the second tranche of its long-range transmission plan. Within this second tranche of projects, we anticipate OTP will be a partial owner of three projects, including a new 345 kV transmission line, a new 765 kV transmission line, and the addition of a second circuit to an existing 345 kV transmission line. These projects will be developed and constructed over several years and OTP's total investment in these projects is estimated to be \$700 million.

Bison-Alexandria includes the construction of a second 345 kV circuit, which is being added to an existing transmission line in eastern North Dakota and western Minnesota. This project is in the initial stages of planning and development and is expected to be completed in 2032.

Maple River-Cuyuna includes the construction of a new 345 kV transmission line in eastern North Dakota and western Minnesota, as well as investment in substation expansion. This project is in the initial stages of planning and development and is expected to be completed in 2033.

Big Stone South-Brookings County includes the construction of a new 765 kV transmission line in eastern South Dakota, as well as investment in substation expansion. This project is in the initial stages of planning and development and is expected to be completed in 2034.

Joint Targeted Interconnection Queue (JTIQ). In December 2024, MISO and Southwest Power Pool (SPP) approved a set of transmission projects that are part of a collaboration between MISO and SPP to construct high-voltage transmission lines along the MISO and SPP seam, which spans seven states - Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota and South Dakota. These projects will improve reliability and resolve constraints in the transmission system to allow for up to 30 gigawatts of new generation to be added to the system.

OTP expects to participate in one JTIQ project, being the sole owner of a new 345 kV transmission line spanning from Big Stone, South Dakota to Hankinson, North Dakota, and a partial owner of a new 345 kV line spanning from Hankinson, North Dakota to Bison, North Dakota. In October 2023, the U.S. Department of Energy (DOE) approved a grant in an amount up to 25% of the total JTIQ project costs. OTP's capital investment in these projects, after the impact of the 25% DOE grant, is estimated to be \$450 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 capital 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 over OTP covered by each regulatory agency:

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

In addition to base rates, which are established through periodic rate case proceedings within each state jurisdiction, there are other mechanisms for recovery of our capital investments and operating costs 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 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.

Under North Dakota law, utilities are required to submit for approval by the North Dakota Public Service Commission (NDPSC) a 15-year advance IRP every three years.

South Dakota does not have a formal advance IRP process.

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 July 30, 2024, allows for an equity-to-total-capitalization ratio between 47.2% and 57.7%, with total capitalization not to exceed \$2.2 billion.

Renewable Energy Standard

Minnesota has adopted 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.

Minnesota Clean Energy Law

In February 2023, Minnesota enacted the Clean Energy Law, 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 anticipate at least 80% of our Minnesota retail sales will be served with carbon-free generation by 2030, in compliance with Minnesota's clean energy requirements.

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 other emission reduction measures which may require future capital investments or ongoing operating and monitoring costs.

Financial Impacts

For the five-year period ended December 31, 2024, OTP invested approximately \$4.8 million in environmental control equipment, including \$1.7 million in 2024. Our capital budget for the next five years includes approximately \$9.0 million of capital investments in environmental control equipment. The timing and amount of our expenditures may change as the regulatory environment changes.

Emerging Environmental Regulation

Regional Haze Rule (RHR). The Environmental Protection Agency (EPA) adopted the RHR 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 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 to periodically evaluate whether those goals and progress are on track or whether additional emission reductions are necessary. The second RHR implementation period covers the years 2018-2028.

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 North Dakota Department of Environmental Quality (NDDEQ) submitted its SIP to the EPA in August 2022. In its plan, the NDDEQ concluded it is not reasonable to require additional emission controls during this planning period.

On December 2, 2024, the EPA published its final ruling on North Dakota's SIP, approving certain aspects of the plan and disapproving other aspects of the plan. Regarding the partial disapproval, the EPA found that North Dakota failed to submit a long-

term strategy that includes enforceable emissions limitations, compliance schedules, and other measures necessary to make reasonable progress on national visibility goals. Specific to Coyote Station, the EPA found that North Dakota relied on non-statutory visibility modeling to reject the installation of additional nitrogen oxides (NO_x) and sulfur dioxide (SO₂) emission controls.

Having disapproved, in part, the North Dakota SIP, the EPA now must promulgate a Federal Implementation Plan within two years from the issuance of its final decision. The Federal Implementation Plan may include emission controls required to satisfy the requirements of the RHR.

We cannot predict with certainty the final resolution of regional haze compliance in North Dakota and specifically the impact, if any, on the operations of Coyote Station. However, significant emission control investments could be required which may have a material impact on our operating results, financial condition and liquidity. Alternatively, such investments may prove to be uneconomic and result in the early closure, sale of or withdrawal from our interest in Coyote Station.

Clean Air Act. In May 2024, the EPA finalized new regulations under Section 111 of the Clean Air Act to regulate GHG emissions from existing and new fossil fuel-based power plants. The final rule establishes subcategories for new combustion turbines and existing coal-fired power plants to achieve certain CO₂ emission reduction levels based on the respective subcategory. For existing coal-fired power plants, the applicable subcategory is based upon the date at which the plant will cease operations.

For existing coal-fired power plants anticipated to be operated after January 2039, the regulation set a Best System of Emission Reduction (BSER) based on 90% capture and sequestration of CO₂ emissions with a compliance date of January 2032. For existing coal-fired power plants anticipated to be operated after January 2032 but plan to cease operations before January 2039, the regulation set a BSER of 40% co-firing with natural gas, which would result in a 16% reduction in CO₂ emissions rate with a compliance date of January 2030. Coal-fired power plants with federally enforceable plans to cease operations by January 2032 are not subject to this regulation.

Several states and industry groups have filed lawsuits challenging the new regulation, arguing the EPA has overstepped its authority under the Clean Air Act.

We continue to review and evaluate the final regulations and the ongoing legal challenges. We cannot at this time conclude what the impact may be on our power plants and the potential impact to our operating results, financial condition and liquidity. However, significant emission control investments could be required, which may have a material impact on our operating results, financial condition and liquidity. Alternatively, such investments may prove to be uneconomic and result in the early closure, sale of or withdrawal from our interest in a coal-fired plant. Coyote Station and Big Stone Plant, our two co-owned coal-fired power plants, are within the scope of the regulations but our combustion turbines are not within the scope of the final regulation.

Coal Combustion Residual (CCR) Regulation. In May 2024, the EPA published a final rule amending CCR regulations, which introduce new requirements for the management of coal ash at active coal-fired power plants and inactive coal-fired power plants with a legacy surface impoundment. The regulations impose new requirements including groundwater monitoring, closure standards, post-closure care obligations and potential remediation activities. We anticipate we will incur costs related to coal ash removal and groundwater monitoring in the future as a result of the amended regulation; however, we continue to review and evaluate the overall impact this regulation may have on our business, including potential impacts to our operating results, financial condition and liquidity.

Mercury and Air Toxics Standards. In May 2024, the EPA published final regulations to strengthen and update Mercury and Air Toxics Standards for coal-fired power plants, tightening the emission standard for toxic metals and finalizing a reduction standard for mercury from existing lignite-fired sources. We continue to review and evaluate the overall impact this regulation may have on our business, including potential impacts to 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, many states and international organizations are pursuing climate policies to regulate GHG emissions as part of a broad-based effort to limit global warming.

The Minnesota Clean Energy Law, passed in 2023, 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 Minnesota Clean Energy Law, regulations under the Clean Air Act and other existing or future federal or state regulations targeting GHG emissions, may have a significant impact on our utility business.

While the future financial impact of any current, proposed or pending 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: 26% (2024), 30% (2023), 27% (2022)

Our Manufacturing businesses are engaged in the production of metal or plastics products sold to commercial customers. 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. BTD is a full-service contract metal fabricator with capabilities in metal stamping and fabrication, tool and die, machining, tube bending, welding, assembly and product painting.

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

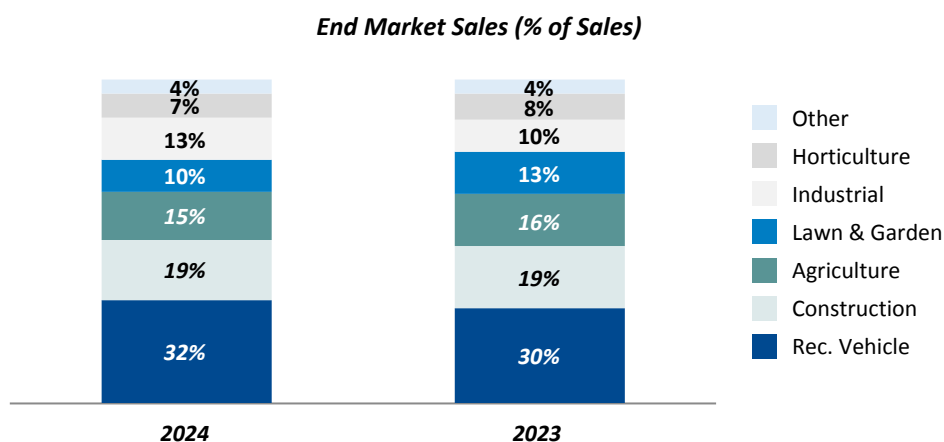
Our metal fabrication business primarily serves Midwestern and Southeastern U.S. original equipment manufacturers (OEM) in the recreational vehicle, lawn and garden, agricultural, construction, industrial, energy equipment and other end markets. Our customers include some of the largest recreational vehicle and equipment manufacturers based in the U.S.

Our plastic products business primarily serves U.S. customers in the horticulture, medical and life sciences, industrial, recreational and electronics industries. Most of our horticulture products are sold through distributors. Our customer packaging products are manufactured to customer specifications and sold directly to the end customer.

Although we sell our products to a large number of customers across a diverse group of end markets, two customers combined to account for approximately 36% of segment operating revenues in 2024.

The principal method of production distribution is by direct shipment to our customers through direct customer pick-up or common carrier ground transportation.

The following presents our revenue by end market for the years ended December 31, 2024 and 2023:



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 domestic and international 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.

In December 2024, we completed an expansion project at our Georgia location, which added approximately 162,000 square feet of owned manufacturing and warehouse space and will replace a warehouse facility that is currently being leased near the same location. This expansion provides additional manufacturing capacity in the southeastern U.S. to meet customer demand as their manufacturing base expands in the same region.

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.

ENVIRONMENTAL REGULATION

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

PLASTICS

Contribution to Operating Revenues: 35% (2024), 31% (2023), 35% (2022)

Our Plastics businesses produce 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 blended with other materials and 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. We produce pipe in a variety of diameters ranging from 3/4" to 24" and in varying lengths, generally from 10 feet to 20 feet.

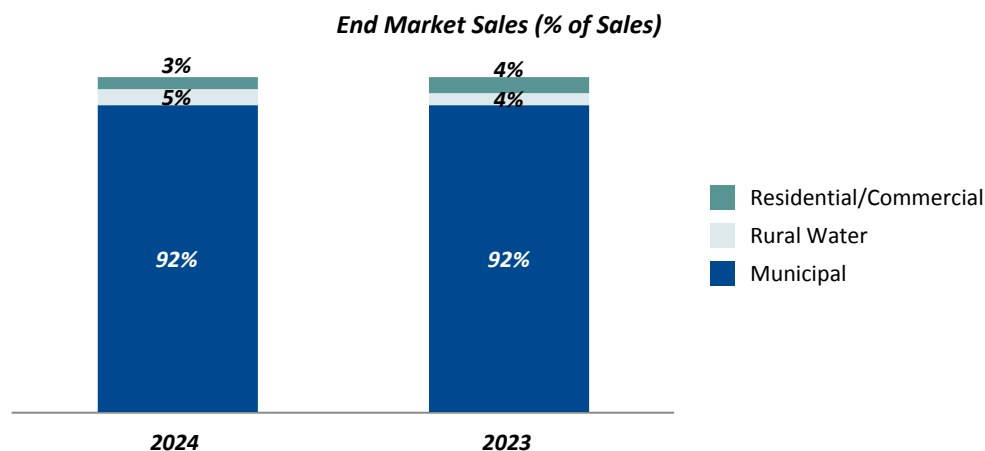
CUSTOMERS

Our PVC pipe is used in municipal and wastewater systems, residential and commercial plumbing applications, and rural water systems.

Our pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Substantially all of our products are sold through distribution partners, which range from large, national distributors to smaller regional or local distributors. In 2024, two customers, both of which are distributors of PVC pipe, combined to account for 52% of segment operating revenues.

The principal method for distribution of our products is by common carrier ground transportation.

The following presents our revenue by end market for the years ended December 31, 2024 and 2023:



COMPETITIVE CONDITIONS

Competition in the plastic pipe industry arises from other PVC pipe manufacturers 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, product availability, shipping costs and product performance.

Industry competition is characterized by a limited number of competitors, with the three largest competitors capturing a significant portion of the overall market. These competitors have a broader geographical reach, integration with PVC resin producers, greater manufacturing capacity and national relationships with key distribution partners. We compete on a regional basis, serving our core markets with strong customer service and high-quality products.

In addition to competition with other PVC pipe manufacturers, our PVC pipe competes with other products that serve the same end markets, including ductile iron, high-density polyethylene (HDPE), steel and concrete pipe products.

We will continue to compete based on our high level of service quality, including being a responsive and reliable partner to our customers, through maintaining product availability, by producing high-quality products and using cost-effective production techniques.

In December 2024, we completed an expansion project at our Arizona location, which added approximately 62,000 square feet of manufacturing, warehouse and office space, allowing for additional manufacturing capacity, including the ability to produce large diameter pipe to serve our customers in our regional market.

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 and in 2024 we utilized all four vendors to source our PVC resin. 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 due to manufacturing capacity and the limited availability of raw material components, along with rail transportation disruptions from PVC resin plants to our facilities. 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 the dynamic supply and demand factors worldwide, historically the market for PVC resin has been cyclical and subject to significant fluctuations in price.

In addition to PVC resin, we use certain other materials, such as stabilizers, waxes, 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. We may not have sufficient insurance coverage to avoid adverse impacts to our operating results or financial condition from damage to our facilities or an interruption in our business. 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 additional 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, ensuring reliability of electric service, 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.

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. 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.

Claims, litigation, government investigations and other proceedings may adversely affect our business, operating results and liquidity.

We are periodically subject to actual and threatened claims, litigation, investigations and other proceedings, including proceedings by governments and regulatory authorities, involving utilities regulation, competition and antitrust, product quality matters, and liability claims.

Any of these proceedings, including the currently ongoing proceedings related to our Plastics segment businesses, could have an adverse effect on our financial condition, operating results and liquidity. It is possible that a resolution of one or more proceedings, including as a result of a settlement, could involve damages, sanctions, consent decrees or orders requiring us to make substantial future payments, prevent us from offering certain products or services, require us to change our business practices in a manner materially adverse to our business, otherwise disrupt our business, divert management resources, damage our reputation or otherwise have a material effect on our operations. The outcomes of these matters are inherently unpredictable and subject to significant uncertainties, and we are unable to determine the likelihood of an outcome or estimate a range of reasonably possible losses, if any, arising from the proceedings at this time.

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. Information systems, both ours and those of third parties, are vulnerable to security breaches by computer hackers and cyber terrorists, system failures, 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 system failure could result in a disruption to our business including, but not limited to, the inability to produce products or serve our customers. A prolonged system failure could negatively impact our operating results. 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 loss of or significant reduction in revenue from any of our key customers could have an adverse effect on our operating results.

In 2024, a single customer provided more than 10% of our consolidated operating revenues, and each of our segments have customers which accounted for over 10% of the segment's operating revenues. In 2024, two customers combined to account for 19% of Electric segment revenues, two customers combined to account for 36% of Manufacturing segment operating revenues and two customers combined to account for 52% of Plastics segment operating revenues, with one of those customers providing more than 10% of our consolidated 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.

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.

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 indebtedness could also impact our operating results.

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, which may negatively impact our financial condition or liquidity.

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.

OTC 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, or a failure to meet the compliance requirements to receive 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

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.

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.

We may be unable to fully recover costs of our co-owned coal-fired generating facilities.

Changes in regulatory, operational or economic factors could result in the early closure or sale of or withdrawal from our interest in a coal-fired 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. In the event of a sale of our interest in a generating facility, we may be unable to negotiate the sale on favorable terms, which could result in the recognition of a loss on the sale. 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 or sale of our interest in a generating facility.

Our IRP, approved in Minnesota by the MPUC in May 2024, directs OTP to commence activities to no longer serve Minnesota customers with capacity or energy from Coyote Station as early as 2029. The discontinuation of service to Minnesota customers from Coyote Station could result in stranded costs, which may significantly impact our operating results, financial condition and liquidity.

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 planning period of the RHR as part of the state of North Dakota's RHR SIP. In December 2024, the EPA partially disapproved the North Dakota SIP related to Coyote Station and now must promulgate a Federal Implementation Plan. The federal plan may include emission controls required to satisfy the requirements of the RHR. We cannot predict with certainty the final resolution of regional haze compliance in North Dakota and specifically the impact, if any, on the operations of Coyote Station. However, significant emission control investments could be required which may have a material impact on our operating results, financial condition and liquidity. Alternatively, such investments may prove to be uneconomic and result in the early closure, 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.

Actions to address climate change and greenhouse gas emissions could materially impact us.

Current and future federal, state, regional and international legislation and 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 May 2024, the EPA finalized new regulations under Section 111 of the Clean Air Act to regulate GHG emissions from existing and new fossil fuel-based power plants. The new regulations require existing coal-fired power plants to achieve certain CO₂ emissions reduction levels, with the amount of reduction dependent upon the remaining operating life of the facility. The new regulation has the potential to materially impact the operations of our coal-fired power plants, which could have a material impact on our operating results, financial condition and liquidity.

In addition to complying with legislation and regulation, we could be subject to litigation related to climate change. If we 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.

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.

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.

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 generation, transmission and distribution facilities could be vulnerable to cyber and physical attack.

OTP owns electric transmission, distribution 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 transmission, distribution and generation 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.

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 to best navigate changing environmental regulations and economic conditions may be impacted by our rights and obligations under the co-ownership and related agreements, and our ability to reconcile a divergence in the interests of OTP and the co-owners of these generation facilities. Such a divergence could impair our ability to effectively manage these changing conditions to meet our strategic objectives, and could adversely impact our financial condition, operating results and liquidity.

We are subject to risks associated with energy and capacity markets.

Our electric business is subject to the risks associated with energy and capacity markets, including changes in market supply, energy and capacity prices. If we need to procure market energy and 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. Changes in our own generation capacity or market capacity, including from changes in capacity accreditation, could lead to increased capacity prices. Significantly higher than expected energy or capacity costs could negatively affect our financial condition, operating results and liquidity.

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 and 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.

MANUFACTURING SEGMENT RISKS

We are impacted by our customers' strategies, operational decisions and conditions in the end markets they serve.

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, industrial, 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:

- 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
- seasonality of demand for our customers' products, which may cause our manufacturing capacity to be underutilized for periods of time;
- 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.

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.

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. 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 and pricing of our PVC pipe products.

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.

Sales prices for PVC pipe began to significantly increase in 2021, reaching a peak level in mid-2022. Pipe prices have since retreated from the high point but remain elevated compared to historic levels. Elevated pipe prices led to a significant expansion in our operating margins and cash generation. We expect sales prices for PVC pipe to continue to decline, which will cause a decline in operating margins and cash generation prospectively. The pace and magnitude of the decline in product pricing could materially impact our operating results and liquidity.

Changes in PVC resin prices could negatively affect our plastics business.

The cost of PVC resin is based on global supply and demand conditions, which can create volatile pricing. Changes in PVC resin cost prices can negatively affect PVC pipe prices and profit margins on PVC pipe sales.

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 2024, we sourced all of our PVC resin needs from four 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 other manufacturers of PVC pipe and manufacturers of alternative products.

Competition in the plastic pipe industry arises from other PVC pipe manufacturers and the fungible nature of the product. Certain of the companies we compete with have a broader geographical reach, integration with PVC resin producers, greater manufacturing capacity and national relationships with key distribution partners. In addition to competing with other plastic pipe manufacturers, our products also compete against similar products serving the same end markets, including ductile iron, HDPE, steel and concrete pipe. Our inability to compete effectively on product price, customer service and product performance may adversely affect the financial performance of our plastics businesses.

GENERAL RISK FACTORS

Changes in economic conditions and economic policies could negatively impact our businesses.

Our businesses are affected by local, national and worldwide economic conditions. Economic recessions, inflation, changes in commodity prices, changes in interest rates and tightening of credit in financial markets could adversely affect our operating results, financial condition and liquidity. In addition, changes in government policies, including trade regulations and tariffs, could impact our businesses, including increasing our costs of materials, negatively impacting our supply chain, reducing sales volumes of our products or services, or disrupting the competitive environment in which we operate. A broad increase in tariffs may also lead to elevated inflation and increased interest rates, which may negatively impact national economic conditions and impact our operating results, financial condition and liquidity.

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 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 our 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 reviews 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. At least 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, 2024.

ELECTRIC SEGMENT

The following reflects our wholly or jointly owned material electric generation facilities as of December 31, 2024:

<i>Description</i>	<i>Location</i>	<i>Year Placed in Service</i>	<i>Fuel Type</i>	<i>Capacity - kW (Nameplate Rating)</i>
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 ⁽³⁾	Barnes County, ND	2023	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, 2024 as follows:

	<i>Miles</i>
Transmission	
345 kV ⁽¹⁾	890
230 kV ⁽²⁾	496
115 kV	974
Less than 115 kV	3,998
Distribution	
Less than 115 kV	7,870

⁽¹⁾ As of December 31, 2024, 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.

⁽²⁾ As of December 31, 2024, 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 properties of our Manufacturing and Plastic segments as of December 31, 2024 which are significant to our operations:

<i>Segment/Location</i>	<i>Owned/Leased</i>	<i>Facility Type/Use</i>	<i>Approximate Square Feet</i>
Manufacturing Segment			
Otsego, MN	Leased	Manufacturing/Warehouse	86,000
Clearwater, MN	Owned	Office/Manufacturing/Warehouse	204,000
Washington, IL	Leased	Office/Manufacturing/Warehouse	218,000
Sauk Rapids, MN	Leased	Warehouse	278,000
Dawsonville, GA	Owned	Office/Manufacturing/Warehouse	334,000
Detroit Lakes, MN	Owned	Office/Manufacturing/Warehouse	354,000
Lakeville, MN	Leased	Office/Manufacturing/Warehouse	413,000
Plastics Segment			
Fargo, ND	Owned	Office/Manufacturing/Warehouse	122,000
Phoenix, AZ	Owned	Office/Manufacturing/Warehouse	149,000

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

ITEM 3. LEGAL PROCEEDINGS

Several class action complaints have been filed against certain PVC pipe manufacturers, including OTC, alleging, among other things, that the defendants conspired to fix, raise, maintain, and stabilize the price of PVC municipal water and electrical conduit pipe in violation of United States antitrust laws. See [Note 14, Commitments and Contingencies](#), to the consolidated financial statements, which information is incorporated herein by reference, for further discussion of this matter.

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 our 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 (60)	04/13/15	President and Chief Executive Officer
Todd R. Wahlund (54)	01/01/24	Vice President, Chief Financial Officer
Timothy J. Rogelstad (58)	04/14/14	Senior Vice President, Electric Platform
John S. Abbott (66)	02/11/15	Senior Vice President, Manufacturing Platform
Jennifer O. Smestad (54)	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 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

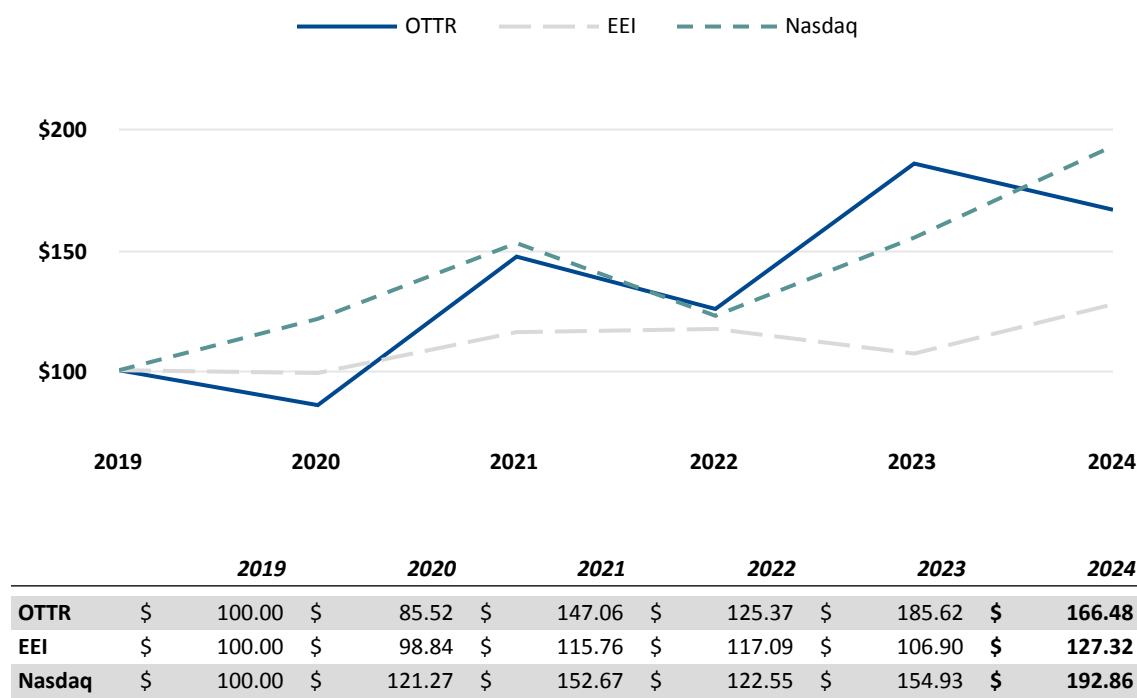
ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the Nasdaq Global Select Market under the Nasdaq symbol "OTTR". As of December 31, 2024, there were 10,245 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, 2024.

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, 2019, and reinvestment of all dividends).



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.

2024 FINANCIAL RESULTS

In 2024, our diversified business model generated record financial results, producing net income of \$301.7 million, or \$7.17 per diluted share, an increase of 3% from \$294.2 million, or \$7.00 per diluted share, in 2023. Our financial results for the year were driven by earnings growth in our Electric and Plastics segments, partially offset by a decline in our Manufacturing segment earnings. In 2024, we paid an annual dividend of \$1.87 per share, or \$78.3 million, completing our 86th consecutive year of dividend payments to our shareholders.

Our Electric segment produced earnings growth of 8% in 2024, from \$84.4 million in 2023 to \$91.0 million in 2024, primarily due to increased retail revenue resulting from an interim rate increase in North Dakota and increased rider revenue, partially offset by the investment and financing costs associated with our rate base investments, resulting in increased depreciation and interest expense compared to the prior year.

Our Manufacturing segment earnings decreased 36% in 2024, from \$21.5 million in 2023 to \$13.7 million in 2024, primarily due to soft end market demand, which resulted in lower sales volumes and a decrease in gross profit margins in our plastics thermoforming business, partially offset by reduced general and administrative expenses. Decreased profit margins were primarily due to reduced leveraging of fixed manufacturing costs resulting from decreased production and sales volumes.

Our Plastics segment produced earnings growth of 7%, from \$187.7 million in 2023 to \$200.7 million in 2024, primarily due to the impact of increased sales volumes, driven by strong customer and end market demand. Increased operating revenues, driven by increased sales volumes, were partially offset by a decrease in gross profit margins. Gross profit margins decreased primarily due to decreases in sales prices, which outpaced decreases in the cost of PVC resin and other input materials.

Our earnings mix in 2024 was 30% from our Electric segment and 70% from the combination of our Manufacturing and Plastics segments including unallocated corporate costs. Since 2021, our earnings mix has diverged from our long-term target of 65% from our Electric segment and 35% from our Manufacturing Platform primarily due to market conditions within the PVC pipe industry. These conditions have led to significant revenue, earnings and cash flow growth in our Plastics segment. Currently, we expect these industry conditions to gradually normalize through 2027. As they do, we expect earnings and cash flow generation within our Plastics segment to moderate from current levels and our earnings mix to return to our long-term targeted mix.

PVC PIPE MARKET 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 four years. Periodic disruptions in the supply of PVC 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. During this time, robust end market demand for PVC pipe led to a rapid and significant increase in sales prices for the product, significantly outpacing the increase in resin input costs, leading to increased operating margins within our Plastics segment. PVC pipe prices and resin costs reached historic levels, peaking in 2022. Sales prices have steadily declined since the third quarter of 2022, a trend that continued throughout 2024; however, operating margins remain elevated relative to historical levels.

In the second half of 2022, our sales volumes declined in response to uncertain and competitive market conditions, which continued through the first half of 2023. Robust infrastructure investment plans, particularly in water supply, sewage, and drainage systems, and increased construction activity drove strong distributor and end market demand for PVC pipe beginning in the second half of 2023 and those trends continued throughout 2024.

The market dynamics impacting our Plastics segment resulted in a significant increase in earnings in the last four years compared to historical levels. We anticipate PVC pipe sales prices will continue to decline over time; however, future supply and demand dynamics, as well as other factors, could impact future product prices. We anticipate PVC pipe prices will gradually normalize through 2027. 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.

RESULTS OF OPERATIONS

For a comparison of fiscal year 2023 to 2022, 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, 2023, filed with the SEC on February 14, 2024.

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, 2024 and 2023:

<i>(in thousands)</i>	2024	2023	\$ change	% change
Operating Revenues	\$ 1,330,548	\$ 1,349,166	\$ (18,618)	(1.4)%
Operating Expenses	950,298	971,247	(20,949)	(2.2)
Operating Income	380,250	377,919	2,331	0.6
Interest Expense	(41,815)	(37,677)	(4,138)	11.0
Nonservice Components of Postretirement Benefits	9,609	10,597	(988)	(9.3)
Other Income	18,848	12,650	6,198	49.0
Income Before Income Taxes	366,892	363,489	3,403	0.9
Income Tax Expense	65,230	69,298	(4,068)	(5.9)
Net Income	\$ 301,662	\$ 294,191	\$ 7,471	2.5 %

Operating Revenues decreased \$18.6 million on a consolidated basis in 2024. Electric segment operating revenues decreased 1% primarily due to decreased fuel recovery and wholesale revenues and the impact of unfavorable weather, partially offset by retail revenue increases due to an interim rate increase in North Dakota in connection with our most recent rate case, as well as increased commercial and industrial sales volumes, and increased rider revenue. Manufacturing segment operating revenues decreased 15% primarily due to lower sales volumes due to soft end market demand across most end markets. Plastics segment operating revenues increased 11% primarily due to increased sales volumes driven by strong customer demand, partially offset by a decrease in sales prices. See our segment disclosures below for additional discussion of items impacting operating revenues.

Operating Expenses decreased \$20.9 million in 2024. Electric segment operating expenses decreased primarily due to decreased purchased power costs resulting from lower market energy prices. Operating expenses in our Manufacturing segment decreased primarily due to decreased sales volumes, as discussed above. Operating expenses in our Plastics segment increased primarily due to increased sales volumes, as discussed above. See our segment disclosures below for additional discussion of items impacting operating expenses.

Interest Expense increased \$4.1 million in 2024 due to the issuance of an additional \$120.0 million of long-term debt at OTP in March, the proceeds of which were used to repay short-term borrowings, fund capital expenditures and support operating activities.

Other Income increased \$6.2 million in 2024 primarily due to an increase in investment income earned on our short-term cash equivalent investments and our long-term fixed income investments.

Income Tax Expense decreased \$4.1 million in 2024 primarily due to an increase in PTCs produced by our wind and solar generation assets. Our effective tax rate was 17.8% in 2024 and 19.1% in 2023. See [Note 13](#) 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, 2024 and 2023:

<i>(in thousands)</i>	2024	2023	\$ change	% change
Retail Revenue	\$ 453,214	\$ 455,840	\$ (2,626)	(0.6)%
Transmission Services Revenue	53,517	52,555	962	1.8
Wholesale Revenue	11,077	12,459	(1,382)	(11.1)
Other Electric Revenues	6,707	7,505	(798)	(10.6)
Total Operating Revenue	524,515	528,359	(3,844)	(0.7)
Production Fuel	60,945	60,339	606	1.0
Purchased Power	61,561	78,292	(16,731)	(21.4)
Operating and Maintenance Expenses	190,422	191,263	(841)	(0.4)
Depreciation and Amortization	82,136	75,330	6,806	9.0
Property Taxes	15,662	16,614	(952)	(5.7)
Operating Income	113,789	106,521	7,268	6.8
Interest Expense	(38,216)	(33,864)	(4,352)	12.9
Nonservice Cost Components of Postretirement Benefits	10,578	11,661	(1,083)	(9.3)
Other Income	3,268	1,754	1,514	86.3
Income Before Income Taxes	89,419	86,072	3,347	3.9
Income Tax (Benefit) Expense	(1,544)	1,648	(3,192)	(193.7)
Net Income	\$ 90,963	\$ 84,424	\$ 6,539	7.7 %

Electric kwh Sales <i>(in thousands)</i>	2024	2023	change	% change
Retail kwh Sales	5,681,268	5,772,215	(90,947)	(1.6)%
Wholesale kwh Sales	273,365	351,729	(78,364)	(22.3)
Heating Degree Days	5,313	6,259	(946)	(15.1)
Cooling Degree Days	440	590	(150)	(25.4)%

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, 2024 and 2023:

	2024	2023
Heating Degree Days	83.7 %	98.4 %
Cooling Degree Days	93.8 %	127.2 %

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, 2024 and 2023, and between years:

	2024 vs Normal	2024 vs 2023	2023 vs Normal
Effect on Diluted Earnings Per Share	\$ (0.13)	\$ (0.15)	\$ 0.02

Retail Revenue decreased \$2.6 million primarily due to the following:

- A \$13.4 million decrease in fuel recovery revenues, primarily due to lower purchased power costs, as described below.
- A \$8.1 million decrease in base revenues from the unfavorable impact of weather compared to last year.

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

- A \$12.4 million increase from an interim rate increase in North Dakota, effective January 1, 2024, in connection with our most recent rate case.
- A \$3.2 million increase in rider revenues, including recovery of our continued investments in advanced metering and outage management systems and wind repowering projects.
- Increased sales volumes to commercial and industrial customers, the mix of customer rates compared to the prior year and other factors.

Purchased Power costs to serve retail customers decreased \$16.7 million due to a 17% decrease in the price of purchased power, primarily due to decreased market energy costs, as well as a 5% decrease in the volume of purchased power primarily due to decreased demand resulting from unfavorable weather.

Operating and Maintenance Expense decreased \$0.8 million primarily due to decreased vegetative maintenance, outage, transmission tariff and insurance costs, partially offset by increased labor, software and environmental protection costs.

Depreciation and Amortization expense increased \$6.8 million primarily due to the placing in service of our metering infrastructure project throughout the year, a full year of depreciation recognized for Hoot Lake Solar, which was placed in service in August 2023, and continued investments in distribution facilities during the year.

Property Taxes decreased \$1.0 million due to lower taxes associated with certain wind farm facilities in North Dakota due to a revision of the tax methodology applied to the property and lower taxes in Minnesota.

Interest Expense increased \$4.4 million due to the issuance of an additional \$120.0 million of long-term debt in March, partially offset by lower interest on short-term borrowings due to lower average borrowings and interest rates compared to the prior year.

Income Tax Expense decreased \$3.2 million due to an increase in PTCs produced by our wind and solar generation assets, partially attributable to Hoot Lake Solar going into service in August 2023.

MANUFACTURING SEGMENT RESULTS

The following table summarizes the operating results of our Manufacturing segment for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023	\$ change	% change
Operating Revenues	\$ 342,592	\$ 402,781	\$ (60,189)	(14.9)%
Cost of Products Sold (excluding depreciation)	267,904	310,601	(42,697)	(13.7)
Selling, General, and Administrative Expenses	35,203	44,545	(9,342)	(21.0)
Depreciation and Amortization	20,393	18,495	1,898	10.3
Operating Income	19,092	29,140	(10,048)	(34.5)
Interest Expense	(2,516)	(2,295)	(221)	9.6
Other Income	—	(1)	1	(100.0)
Income Before Income Taxes	16,576	26,844	(10,268)	(38.3)
Income Tax Expense	2,895	5,390	(2,495)	(46.3)
Net Income	\$ 13,681	\$ 21,454	\$ (7,773)	(36.2)%

Operating Revenues decreased \$60.2 million primarily due to a 15% decrease in sales volumes, with declines experienced in the recreational vehicle, agriculture, construction, lawn and garden, and horticulture end markets. Sales volumes decreased due to lower end market demand and inventory management efforts by manufacturers, distributors and dealers. A 28% decline in scrap metal revenues, largely driven by lower production volumes, also contributed to the decrease in operating revenues.

Cost of Products Sold decreased \$42.7 million primarily due to lower sales volumes, as described above. In response to declines in end market demand and decreased sales volumes, we reduced our headcount and operating hours and placed employees on temporary furlough during the year, which also reduced our costs. These decreases were partially offset by reduced leveraging of fixed manufacturing costs resulting from the decreased production and sales volumes.

Selling, General, and Administrative Expenses decreased \$9.3 million primarily due to decreased employee compensation costs resulting from a decrease in headcount and lower variable compensation driven by financial performance in the current year.

Depreciation and Amortization increased \$1.9 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, 2024 and 2023:

<i>(in thousands)</i>	2024	2023	\$ change	% change
Operating Revenues	\$ 463,441	\$ 418,026	\$ 45,415	10.9 %
Cost of Products Sold (excluding depreciation)	166,628	143,521	23,107	16.1
Selling, General, and Administrative Expenses	20,414	16,076	4,338	27.0
Depreciation and Amortization	4,494	4,027	467	11.6
Operating Income	271,905	254,402	17,503	6.9
Interest Expense	(590)	(602)	12	(2.0)
Other Income	76	14	62	442.9
Income Before Income Taxes	271,391	253,814	17,577	6.9
Income Tax Expense	70,644	66,066	4,578	6.9
Net Income	\$ 200,747	\$ 187,748	\$ 12,999	6.9 %

Operating Revenues increased \$45.4 million primarily due to a 27% increase in sales volumes driven by customer sales volume growth and strong distributor and end market demand. Sales volumes in 2023 were negatively impacted by distributors and contractors reducing purchase volumes in response to uncertain and competitive market conditions. Although market conditions remain somewhat uncertain, infrastructure investment and active construction across our sales territories contributed to increased distributor and end market demand in 2024. The impact of increased sales volumes was partially offset by decreased sales prices. Our sales prices have steadily declined after peaking in late 2022 and decreased 12% in 2024 compared to the prior year due to continuing changes in market conditions.

Cost of Products Sold increased \$23.1 million primarily due to increased sales volumes, as described above. The supply and demand conditions for PVC resin experienced in recent years appear to have normalized and resin costs were less volatile throughout the year than they were in the recent past. The cost of PVC resin and other input materials decreased 13% compared to the prior year, partially offsetting the impact of increased sales volumes.

Selling, General, and Administrative Expenses increased \$4.3 million due to costs associated with ongoing litigation regarding the pricing of PVC pipe, which is further described in [Note 14](#) to the consolidated financial statements, as well as increased variable costs associated with our increase in sales volumes and current year financial performance.

CORPORATE

The following table summarizes Corporate results of operations for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023	\$ change	% change
Selling, General, and Administrative Expenses	\$ 24,438	\$ 12,042	\$ 12,396	102.9 %
Depreciation and Amortization	98	102	(4)	(3.9)
Operating Income (Loss)	(24,536)	(12,144)	(12,392)	102.0
Interest Expense	(493)	(916)	423	(46.2)
Nonservice Cost Components of Postretirement Benefits	(969)	(1,064)	95	(8.9)
Other Income	15,504	10,883	4,621	42.5
Income (Loss) Before Income Taxes	(10,494)	(3,241)	(7,253)	223.8
Income Tax (Benefit)	(6,765)	(3,806)	(2,959)	77.7
Net Income (Loss)	\$ (3,729)	\$ 565	\$ (4,294)	(760.0)%

Selling, General, and Administrative Expenses increased \$12.4 million primarily due to increased insurance expense driven by higher claims costs associated with our self-funded insurance programs, as well as increased variable compensation based on the current year financial performance.

Other Income increased \$4.6 million primarily due to an increase in investment income earned on our short-term cash equivalent investments and our long-term fixed income investments, primarily due to additional investments made during the year driven by an increase in cash available for investment.

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 ⁽¹⁾⁽²⁾	03/15/25	225.6	7.53	10.10	53.50
South Dakota ⁽³⁾	08/01/19	35.5	7.09	8.75	52.92

⁽¹⁾ Includes an earnings sharing mechanism to share with North Dakota customers any earnings above an ROE of 10.20%. The mechanism requires 70% of any revenue creating annual earnings in excess of the authorized ROE be returned to customers.

⁽²⁾ A compliance filing affirming the implementation date, revenue requirement, return on rate base, allowed return on equity, and equity ratio was made on February 7, 2025, and remained subject to final approval by the NDPSC as of the date of this annual report on Form 10-K.

⁽³⁾ 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 ROE of 10.6% on an equity ratio of 53.5% of total capital. The filing also 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. Interim rates went into effect on January 1, 2024. On July 3, 2024, OTP filed an update to the original request increasing the amount of the net annual revenue requirement increase from \$17.4 million to \$22.5 million, or a net increase of 10.9% in annual revenue, to account for certain items identified throughout the regulatory process.

On December 30, 2024, the NDPSC approved a settlement agreement between OTP and certain interested parties in the general rate case and issued its written order on final rates. The key provisions of the order include a revenue requirement of \$225.6 million, based on a return on rate base of 7.53%, and an allowed ROE of 10.10% on an equity ratio of 53.5%. The net annual revenue requirement includes a net increase of \$13.1 million, or 6.18%. OTP's revenue requirement was reduced by approximately \$3.0 million primarily due to the inclusion of forecasted PTCs plus adjustments for new customer load additions, which were not included in OTP's updated request filed on July 3, 2024. Through the settlement of the case, the parties also agreed to establish an earnings sharing mechanism, whereby 70% of actual earnings in excess of a 10.20% ROE would be returned to customers, with OTP retaining the remaining 30%.

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.
ECO - 2024	MN	Approved	04/01/24	8.8	10/01/24	Recovery of energy conservation improvement costs as well as a demand side management financial incentive.
RRR - 2024	MN	Approved	12/04/23	8.0	09/01/24	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.
EUIC - 2025	MN	Approved	05/03/24	4.1	02/01/25	Recovery of advanced metering infrastructure, outage management system, geographic information system, and demand response projects.
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.
TCR - 2025	ND	Approved	09/16/24	3.1	01/01/25	Recovery of transmission project costs.
PIR - 2024	SD	Approved	06/03/24	3.2	09/01/24	Recovery of Ashtabula III, Merricourt, Astoria Station, wind upgrade projects, Advanced Grid Infrastructure project costs, and impact of load growth credits.
PIR - 2025	SD	Requested	12/20/24	3.2	09/01/25	Recovery of Ashtabula III, Merricourt, Astoria Station, wind upgrade projects, advanced metering infrastructure, outage management system, demand response system, and impact of load growth credits.
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

Minnesota

In May 2024, the MPUC approved OTP's 2023 to 2037 IRP. Consistent with MPUC practice, the decision was made during deliberations by oral vote and was finalized in a written order issued in July 2024.

The MPUC:

- Directed OTP to procure the following generation resources, subject to additional regulatory review and approval:
 - 200 to 300 MW of solar generation by November 1, 2027, or as soon as practicable thereafter,
 - 150 to 200 MW of wind generation by December 31, 2029, or as soon as practicable thereafter,
 - 20 to 75 MW of battery storage by December 31, 2029, or as soon as practicable thereafter;
- Approved the project to add on-site liquified natural gas storage at our Astoria Station natural gas plant by 2027;
- Directed OTP to designate the Minnesota share of the jointly owned Coyote Station coal-fired plant as an Available Maximum Emergency (AME) resource beginning in 2026 and ending no later than December 2031. If the designation as an AME resource is found to not be feasible, then Minnesota customers shall not continue to pay for or depend on capacity or energy from Coyote Station past 2028; and
- Directed OTP to commence activities to no longer serve Minnesota customers with capacity or energy from Coyote Station as soon as feasible and no later than December 31, 2031.

Under the MPUC's order, OTP will file its next IRP in May 2026. In this filing, the company will include, among other options, an analysis considering the continued operation of Big Stone Plant with AME.

North Dakota

In December 2024, the NDPSC issued its final order on OTP's IRP. The order stipulated that the commission does not support the addition of new wind or solar generation or battery storage through 2030. Therefore, none of the costs or benefits of the new renewable and battery storage assets in OTP's IRP approved by the MPUC will be assigned to North Dakota customers, including any that may be physically located in North Dakota. In addition, at an informal hearing in July 2024, the NDPSC denied our request for an Advanced Determination of Prudence (ADP) for the on-site liquified natural gas storage at Astoria Station, a project that was part of OTP's IRP approved by the MPUC. We continue to evaluate the benefits of on-site fuel storage at Astoria Station and the development of this project in the future.

LIQUIDITY

LIQUIDITY OVERVIEW

We believe our financial condition is strong and our cash and cash equivalents, 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, fund our capital expenditure program and satisfy our obligations as they become due. Our liquidity, including our operating cash flows and access to capital markets, could be impacted by macroeconomic factors outside of our control, including higher interest rates and debt capital costs, and diminished credit availability. In addition, our liquidity could be impacted by non-compliance with certain financial covenants under our various debt instruments. As of December 31, 2024, we were in compliance with all financial 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, 2024:

(in thousands)	Line Limit	2024		
		Amount Outstanding	Letters of Credit	Amount Available
OTC Credit Agreement	\$ 170,000	\$ —	\$ —	\$ 170,000
OTP Credit Agreement	220,000	69,615	8,772	141,613
Total	\$ 390,000	\$ 69,615	\$ 8,772	\$ 311,613

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 \$300 million, subject to certain terms and conditions.

As of December 31, 2024, we had \$311.6 million of available liquidity under our credit agreements and \$294.7 million of available cash and cash equivalents, resulting in total available liquidity of \$606.3 million, compared to total available liquidity of \$479.8 million as of December 31, 2023.

CASH FLOWS

The following is a discussion of our cash flows for the years ended December 31, 2024 and 2023:

(in thousands)	2024	2023
Net Cash Provided by Operating Activities	\$ 452,731	\$ 404,499

Net Cash Provided by Operating Activities increased \$48.2 million primarily due to a decrease in working capital and increased net income. In our Plastics segment, sales and related receivable balances were less volatile than the prior year where sales and related receivable balances increased in the later part of the year. This resulted in decreased working capital in the current year compared to the prior year. Working capital also decreased due to an increase in payables in our Electric segment, due to the timing of capital investment spending, and decreases in receivables and inventories in our Manufacturing segment, due to decreased sales and production volumes during the later part of the current year.

Market dynamics experienced by our Plastics segment businesses in 2024 and 2023 resulted in a significant increase in our overall cash from operations compared to prior periods. We anticipate our cash from operations in future years will decline from current levels consistent with the anticipated decline in Plastics segment earnings.

<i>(in thousands)</i>	2024		2023	
Net Cash Used in Investing Activities	\$	411,374	\$	289,287

Net Cash Used in Investment Activities increased \$122.1 million primarily due to an increase in capital expenditures. Capital expenditures during the year included additional investments in our wind repowering and advanced metering and outage management projects at OTP, as well as continued investments in our manufacturing facility expansion projects in Arizona and Georgia. A \$50.1 million investment in U.S. treasuries made during the year to secure a fixed rate of return until their maturity in September 2026 also contributed to the increase in net cash used in investing activities.

<i>(in thousands)</i>	2024		2023	
Net Cash Provided by (Used in) Financing Activities	\$	22,921	\$	(3,835)

Net Cash Provided by (Used in) Financing Activities increased \$26.8 million compared to the prior year. Financing activities during the year included the issuance of \$120.0 million of long-term debt at OTP, the proceeds of which were used to repay short-term borrowings under the OTP credit agreement, fund Electric segment construction expenditures and support operating activities. We manage the capital structure of OTP independently from our consolidated financial position to ensure compliance with the capital structure approved through regulation; therefore, our decision to issue long-term debt at OTP is not impacted by our consolidated cash and cash equivalent position.

Financing activities during the year also included net repayments of short-term debt of \$11.8 million compared to net short-term borrowings of \$73.2 million in 2023, and in 2024, we made dividend payments of \$78.3 million compared to \$73.1 million in 2023.

CAPITAL REQUIREMENTS

CAPITAL EXPENDITURES

Our capital expenditure plan includes investments in electric generation facilities, transmission and distribution lines and facilities, 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 approvals, business expansion opportunities, the costs of labor, materials and equipment, and our overall financial condition.

The following provides a summary of capital expenditures for the years ended December 31, 2024 and 2023 for our Electric segment and non-electric businesses and anticipated capital expenditures for the five-year period 2025 through 2029:

<i>(in millions)</i>	2023	2024	2025	2026	2027	2028	2029	<i>Total 2025 - 2029</i>
Electric Segment:								
Renewable Generation	\$ 106	\$ 134	\$ 101	\$ 127	\$ 118	\$ 179	\$ 4	\$ 529
Transmission	49	60	59	93	162	114	100	528
Distribution	45	46	37	37	36	37	34	181
Other	41	61	54	51	31	27	25	188
Total Electric Segment	241	301	251	308	347	357	163	1,426
Manufacturing and Plastics Segments	46	58	27	27	27	25	23	129
Total Capital Expenditures	\$ 287	\$ 359	\$ 278	\$ 335	\$ 374	\$ 382	\$ 186	\$ 1,555

CONTRACTUAL AND OTHER OBLIGATIONS

The following table summarizes our contractual obligations on December 31, 2024 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

<i>(in millions)</i>	<i>Total</i>	<i>Less than 1 Year</i>	<i>1-3 Years</i>	<i>3-5 Years</i>	<i>More than 5 Years</i>
Debt Obligations	\$ 1,017	\$ 70	\$ 122	\$ 70	\$ 755
Interest on Debt Obligations	700	42	81	71	506
Coal Contracts	441	24	50	53	314
Land Easements	62	2	4	4	52
Postretirement Benefit Obligations	65	5	11	11	38
Operating Lease Obligations	35	6	10	6	13
Other Obligations	11	2	2	1	6
Total Contractual Obligations	\$ 2,331	\$ 151	\$ 280	\$ 216	\$ 1,684

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. OTP also has contractual agreements for the purchase of capacity and wind-generated energy. Generally, the terms of OTP's wind power purchase agreements require OTP to purchase all of the electricity generated by a particular wind farm, but do not include fixed or minimum payments.

On October 30, 2024, OTP entered into an agreement to acquire the assets of a solar facility currently under development. Under the terms of the agreement, the purchase price is equal to \$23.6 million, plus the reimbursement of certain interconnection costs and costs to purchase and store the main power transformer. Closing of the transaction is expected to occur in late 2025 or early 2026.

COMMON STOCK DIVIDENDS

We paid dividends to our shareholders totaling \$78.3 million, or \$1.87 per share, in 2024. The determination of the amount of future cash dividends to be paid will depend on, among other things, our financial condition, our actual or expected level of earnings and cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by OTC subsidiaries to OTC. These intercompany distributions serve as the primary source of funding for dividends paid to our shareholders. See [Note 15](#) 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 4, 2025, our Board of Directors approved a quarterly dividend of \$0.525 per common share.

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, unused lines of credit, access to capital markets and alternative financing arrangements such as leasing. Debt financing will be required in the five-year period from 2025 through 2029 to refinance maturing debt and to finance our planned capital investments. Our financing plans are subject to change and are impacted by our planned level of capital investments, decisions to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt, to complete acquisitions or to use capital for other purposes.

REGISTRATION STATEMENTS

On May 3, 2024, we filed two registration statements with the SEC, replacing two previously filed registration statements upon their expiration. The first statement, a shelf registration, allows us to offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the registration statement. No new equity, debt, or other securities have been issued pursuant to this registration statement. The second registration statement allows for the issuance of up to 1,500,000 common shares under our Automatic Dividend Reinvestment and Share Purchase Plan, which provides our common 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 newly issued common shares or common shares purchased on the open market. As of December 31, 2024, there were 1,429,531 shares available for purchase or issuance under the plan. Both registration statements expire in May 2027.

SHORT-TERM DEBT

The OTC Credit Agreement and OTP Credit Agreement provide for unsecured revolving lines of credit. In December 2024, the credit agreements were amended to extend the maturity date of each credit facility and amend certain financial covenants. The OTP Credit Agreement was also amended to increase the borrowing limit. 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 borrower. The weighted-average interest rate on all outstanding borrowings as of December 31, 2024 and 2023 was 5.61% and 6.70%.

The following is a summary of key provisions and borrowing information as of and for the year ended December 31, 2024:

<i>(in thousands, except interest rates)</i>	<i>OTC Credit Agreement</i>		<i>OTP Credit Agreement</i>	
Borrowing Limit	\$	170,000	\$	220,000
Borrowing Limit if Accordion Exercised ¹		290,000		300,000
Amount Restricted Due to Outstanding Letters of Credit at Year-End		—		8,772
Amount Outstanding at Year-End		—		69,615
Average Amount Outstanding During Year		—		38,475
Maximum Amount Outstanding During the Year		—		102,024
Interest Rate at Year-End		5.83 %		5.61 %
Expiration Date		December 11, 2029		December 11, 2029

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

LONG-TERM DEBT

In March 2024, OTP entered into a Note Purchase Agreement pursuant to which OTP issued, in a private placement transaction, \$120.0 million of senior unsecured notes consisting of (a) \$60.0 million of 5.48% Series 2024A Senior Unsecured Notes due April 1, 2034, and (b) \$60.0 million of 5.77% Series 2024B Senior Unsecured Notes due April 1, 2054. The proceeds of the notes were used to repay existing short-term borrowings, fund capital expenditures and for general corporate purposes.

As of December 31, 2024, we had \$947.0 million of principal outstanding under long-term debt arrangements. [Note 10](#) 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 2054.

Financial Covenants

Our short- and long-term debt agreements require OTC and OTP to maintain certain financial covenants. As of December 31, 2024, 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 or 0.65 to 1.00, depending on the debt agreement, 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, 2024, OTC's interest-bearing debt to total capitalization was 0.38 to 1.00, OTC's interest and dividend coverage ratio was 10.00 to 1.00 and OTC had no priority indebtedness outstanding.

OTP, under its financial covenants, may not permit its ratio of interest-bearing debt to total capitalization to exceed 0.60 to 1.00 or 0.65 to 1.00, depending on the debt agreement, 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 20% of its total capitalization. As of December 31, 2024, OTP's interest-bearing debt to total capitalization was 0.47 to 1.00, OTP's interest and dividend coverage ratio was 3.34 to 1.00 and OTP 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 current credit ratings of OTC and OTP are summarized below:

	Otter Tail Corporation			Otter Tail Power Company		
	<i>Moody's</i>	<i>Fitch</i>	<i>S&P</i>	<i>Moody's</i>	<i>Fitch</i>	<i>S&P</i>
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	Negative	Stable	Stable

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The discussion and analysis of our results of operations are based on financial statements prepared in accordance with generally accepted accounting principles in the United States of America. Certain of our accounting policies require management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the preparation of our consolidated financial statements. 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 statements 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 statements of income as an expense or income item, or in the consolidated statements of comprehensive income as a loss or gain, in the period in which this accounting treatment is no longer applicable.

As of December 31, 2024 and 2023, we had regulatory assets of \$108.6 million and \$111.8 million and regulatory liabilities of \$318.2 million and \$302.0 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 numerous assumptions, including a discount rate, an expected return on plan assets, a rate of compensation increase and healthcare cost-trend rates. See [Note 11](#) 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. Other assumptions are developed by reference to available trend or historical data adjusted as necessary for future expectations.

On December 31, 2024, the discount rates used to measure our pension plan and postretirement healthcare obligations were 5.70% and 5.61%, a thirteen and eight basis point increase, respectively, from the estimates used on December 31, 2023. Our estimates used to determine benefit cost for 2024 included a discount rate of 5.57% for pension benefits and 5.53% for postretirement healthcare costs, a six and one basis point increase, respectively, from 2023 estimates. In addition, we estimated our assumed rate of return on pension assets to be 7.00% for 2024, which was unchanged from our 2023 estimate.

The following table summarizes the impact on 2024 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	\$ (96)	\$ 931
Rate of Increase in Future Compensation	573	(424)
Long-Term Return on Plan Assets	(911)	911
Other Postretirement Benefits:		
Discount Rate	(14)	15

For 2025, we expect pension and other postretirement benefit income to be \$4.3 million compared to \$8.5 million of income in 2024 due to the impacts of updated actuarial assumptions. See additional information at [Note 11](#) 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, BTD Manufacturing, our contract metal fabrication business, and our Plastics segment. As of December 31, 2024, BTD Manufacturing and our Plastics segment carried a goodwill balance of \$18.1 million and \$19.3 million, respectively.

We historically tested goodwill for impairment as of December 31st each year; however, in 2024, we elected to change the date of our annual goodwill impairment test to October 1st. We believe this new testing date allows us to better align our annual goodwill impairment testing procedures with our year-end financial reporting, as well as our annual budgeting and forecasting process. This change did not delay, accelerate or avoid the recognition of an impairment charge.

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 using income and market approaches. Our income approach uses 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. Our market approach includes estimating the fair value of our reporting units by reference to various market indications of value, including fair value estimates using multiples derived from comparable enterprise values to earnings before interest, taxes, depreciation and amortization (EBITDA) of select peer companies, 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 market approaches require significant judgment in selecting comparable peer companies and comparable sales transactions and from these peer groups selecting an appropriate EBITDA multiple and indication of fair value. In addition, weighting the indications of fair value between the income and market approaches to arrive at a single fair value estimate for each reporting unit also requires judgment.

Our goodwill impairment testing performed in the fourth quarter of 2024 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 3% decrease in projected operating revenues, a one hundred basis point decrease in projected gross profit margins, a one hundred basis point decrease in projected terminal growth rate, a 50 basis point increase in weighted-average cost of capital or a 1.0x decrease in the assumed EBITDA multiple 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 commodity price and interest rate 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, 2024, OTP was party to financial swap agreements with an aggregate notional amount of 167,200 megawatt-hours of electricity with various settlement dates throughout 2025. As of December 31, 2024, the aggregate fair value of these instruments was \$2.0 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 \$0.9 million impact on the fair value of these instruments.

Our Manufacturing and Plastics segment businesses are exposed to market risk arising from changes in commodity prices for certain raw material inputs, including steel, aluminum and PVC and other plastic resins. We manage commodity price risk by attempting to pass 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 and Plastics segment could be impacted.

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, 2024 and 2023, we had \$69.6 million and \$81.4 million of short-term debt outstanding. Holding other variables constant, a 100 basis point change in interest rates during 2024 would have had an approximate \$0.4 million impact to interest expense in 2024 based on our average outstanding short-term debt during the year. As of December 31, 2024 and 2023, we had \$282.0 million and \$219.7 million invested in cash equivalent investments. Holding other variables constant, a 100 basis point change in the average interest rates during 2024 would have had an approximate \$2.3 million impact to our investment income in 2024, based on our average outstanding investment balance during the year.

All of our outstanding long-term debt obligations as of December 31, 2024 and 2023 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, 2024 and 2023, 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, 2024, 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, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, 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, 2024, 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 6 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 judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

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

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs 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 19, 2025

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>	
	2024	2023
Assets		
Current Assets		
Cash and Cash Equivalents	\$ 294,651	\$ 230,373
Receivables, net of allowance for credit losses	145,964	157,143
Inventories	148,885	149,701
Regulatory Assets	9,962	16,127
Other Current Assets	30,579	16,826
Total Current Assets	630,041	570,170
Noncurrent Assets		
Investments	121,177	62,516
Property, Plant and Equipment, net of accumulated depreciation	2,692,460	2,418,375
Regulatory Assets	98,673	95,715
Intangible Assets, net of accumulated amortization	5,743	6,843
Goodwill	37,572	37,572
Other Noncurrent Assets	66,416	51,377
Total Noncurrent Assets	3,022,041	2,672,398
Total Assets	\$ 3,652,082	\$ 3,242,568
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-Term Debt	\$ 69,615	\$ 81,422
Accounts Payable	113,574	94,428
Accrued Salaries and Wages	34,398	38,134
Accrued Taxes	17,314	26,590
Regulatory Liabilities	29,307	25,408
Other Current Liabilities	45,582	43,775
Total Current Liabilities	309,790	309,757
Noncurrent Liabilities and Deferred Credits		
Pension Benefit Liability	32,614	33,101
Other Postretirement Benefits Liability	27,385	27,676
Regulatory Liabilities	288,928	276,547
Deferred Income Taxes	267,745	237,273
Deferred Tax Credits	14,990	15,172
Other Noncurrent Liabilities	98,397	75,977
Total Noncurrent Liabilities and Deferred Credits	730,059	665,746
Commitments and Contingencies (Note 14)		
Capitalization		
Long-Term Debt	943,734	824,059
Shareholders' Equity		
Common Stock: 50,000,000 shares authorized of \$5 par value; 41,827,967 and 41,710,521 outstanding at December 31, 2024 and 2023	209,140	208,553
Additional Paid-In Capital	429,089	426,963
Retained Earnings	1,029,738	806,342
Accumulated Other Comprehensive Income	532	1,148
Total Shareholders' Equity	1,668,499	1,443,006
Total Capitalization	2,612,233	2,267,065
Total Liabilities and Shareholders' Equity	\$ 3,652,082	\$ 3,242,568

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>		
	2024	2023	2022
Operating Revenues			
Electric	\$ 524,515	\$ 528,359	\$ 549,699
Product Sales	806,033	820,807	910,510
Total Operating Revenues	1,330,548	1,349,166	1,460,209
Operating Expenses			
Electric Production Fuel	60,945	60,339	65,110
Electric Purchased Power	61,561	78,292	100,281
Electric Operating and Maintenance Expenses	190,422	191,263	181,378
Cost of Products Sold (excluding depreciation)	434,522	454,122	542,944
Nonelectric Selling, General, and Administrative Expenses	80,065	72,663	69,718
Depreciation and Amortization	107,121	97,954	92,597
Electric Property Taxes	15,662	16,614	17,742
Total Operating Expenses	950,298	971,247	1,069,770
Operating Income	380,250	377,919	390,439
Other Income and (Expense)			
Interest Expense	(41,815)	(37,677)	(36,016)
Nonservice Cost Components of Postretirement Benefits	9,609	10,597	1,075
Other Income (Expense), net	18,848	12,650	2,037
Income Before Income Taxes	366,892	363,489	357,535
Income Tax Expense	65,230	69,298	73,351
Net Income	\$ 301,662	\$ 294,191	\$ 284,184
Weighted-Average Common Shares Outstanding:			
Basic	41,778	41,668	41,586
Diluted	42,072	42,039	41,931
Earnings Per Share:			
Basic	\$ 7.22	\$ 7.06	\$ 6.83
Diluted	\$ 7.17	\$ 7.00	\$ 6.78

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>		
	2024	2023	2022
Net Income	\$ 301,662	\$ 294,191	\$ 284,184
Other Comprehensive Income (Loss):			
Unrealized Gain (Loss) on Available-for-Sale Securities, net of tax (expense) benefit of \$(128), \$(51) and \$115	386	192	(432)
Unrealized Gain (Loss) on Pension and Other Postretirement Benefit Plans, net of tax (expense) benefit of \$352, \$(14) and \$(2,769)	(1,002)	41	7,871
Total Other Comprehensive Income (Loss)	(616)	233	7,439
Total Comprehensive Income	\$ 301,046	\$ 294,424	\$ 291,623

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, 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)
Stock Compensation Expense	—	—	6,814	—	—	6,814
Net Income	—	—	—	284,184	—	284,184
Other Comprehensive Income	—	—	—	—	7,439	7,439
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)
Stock Compensation Expense	—	—	7,753	—	—	7,753
Net Income	—	—	—	294,191	—	294,191
Other Comprehensive Income	—	—	—	—	233	233
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
Employee Stock Purchase Plan Expenses	—	—	(359)	—	—	(359)
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	117,446	587	(7,044)	—	—	(6,457)
Stock Compensation Expense	—	—	9,529	—	—	9,529
Net Income	—	—	—	301,662	—	301,662
Other Comprehensive Loss	—	—	—	—	(616)	(616)
Common Dividends (\$1.87 per share)	—	—	—	(78,266)	—	(78,266)
Balance, December 31, 2024	41,827,967	\$ 209,140	\$ 429,089	\$1,029,738	\$ 532	\$ 1,668,499

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>		
	2024	2023	2022
Operating Activities			
Net Income	\$ 301,662	\$ 294,191	\$ 284,184
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	107,121	97,954	92,597
Deferred Tax Credits	(182)	(744)	(745)
Deferred Income Taxes	23,057	13,508	32,424
Discretionary Contribution to Pension Plan	—	—	(20,000)
Investment (Gains) Losses	(5,482)	(7,222)	3,296
Stock Compensation Expense	9,529	7,753	6,814
Other, net	(3,111)	(423)	(1,473)
Changes in Operating Assets and Liabilities:			
Receivables	11,179	(12,750)	30,560
Inventories	3,691	(2,450)	5,339
Regulatory Assets	5,194	12,479	(2,464)
Other Assets	(11,640)	2,817	(368)
Accounts Payable	14,826	(9,988)	(29,763)
Accrued and Other Liabilities	(10,371)	6	(5,490)
Regulatory Liabilities	16,821	20,973	(6,846)
Pension and Other Postretirement Benefits	(9,563)	(11,605)	1,244
Net Cash Provided by Operating Activities	452,731	404,499	389,309
Investing Activities			
Capital Expenditures	(358,650)	(287,134)	(171,134)
Proceeds from Disposal of Noncurrent Assets	8,849	6,225	4,346
Purchases of Investments and Other Assets	(61,573)	(8,378)	(8,283)
Net Cash Used in Investing Activities	(411,374)	(289,287)	(175,071)
Financing Activities			
Net (Repayments) Borrowings on Short-Term Debt	(11,807)	73,218	(82,959)
Proceeds from Issuance of Long-Term Debt	120,000	—	90,000
Payments for Retirement of Long-Term Debt	—	—	(30,000)
Dividends Paid	(78,266)	(73,061)	(68,755)
Payments for Shares Withheld for Employee Tax Obligations	(6,457)	(3,088)	(2,942)
Other, net	(549)	(904)	(2,123)
Net Cash Provided by (Used in) Financing Activities	22,921	(3,835)	(96,779)
Net Change in Cash and Cash Equivalents	64,278	111,377	117,459
Cash and Cash Equivalents at Beginning of Period	230,373	118,996	1,537
Cash and Cash Equivalents at End of Period	\$ 294,651	\$ 230,373	\$ 118,996
Supplemental Disclosures of Cash Flow Information			
Cash Paid During the Year for:			
Interest, net of amount capitalized	\$ 39,484	\$ 36,956	\$ 35,699
Income Taxes	\$ 57,614	\$ 46,284	\$ 43,411
Supplemental Disclosure of Noncash Investing Activities			
Accrued Property, Plant and Equipment Additions	\$ 20,281	\$ 13,001	\$ 12,420

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.

Regulatory Accounting

Our regulated electric utility 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 statements 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 statements 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 statements of income as an expense or income item, or in the consolidated statements 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 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 not yet billed to a customer, OTP records revenue and an unbilled receivable based on estimates of the amount of energy delivered and a composite rate per kwh consumed.

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 costs 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, 2024 and 2023:

<i>(in thousands)</i>	2024		2023	
Finished Goods	\$	43,345	\$	47,614
Work in Process		22,637		26,354
Raw Material, Fuel and Supplies		82,903		75,733
Total Inventories	\$	148,885	\$	149,701

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, to provide future funding for obligations under nonqualified deferred compensation plans or provide a return on our available cash and liquidity. 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 the 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.

Property, Plant and Equipment

Electric plant is stated at original cost less accumulated depreciation. The cost of additions includes purchased assets, contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction (AFUDC). The amount of interest capitalized to electric plant was \$1.9 million in 2024, \$1.9 million in 2023 and \$0.9 million in 2022. Significant additions or improvements that extend an asset's useful life are capitalized, while repairs and maintenance costs are expensed as incurred.

Depreciation is recognized on a straight-line basis over the asset's estimated useful life. For certain asset classes, we employ a group or composite method of depreciation in which certain assets are combined and depreciated over the average life of the combined asset group. Actuarial studies are periodically performed to assess the remaining useful lives and salvage values of our assets, with any changes in these estimates incorporated into depreciation on a prospective basis. Gains or losses on group or composite asset dispositions are recorded to accumulated depreciation and impact current and future depreciation rates.

Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Removal costs, when incurred, are charged against the regulatory liability.

Property, plant and equipment of our nonelectric operations are carried at historical cost less accumulated depreciation. Depreciation is recognized on a straight-line basis over the asset's estimated useful life. The cost of additions includes purchased assets, contracted work, direct labor and materials, allocable overheads and capitalized interest, as applicable. No interest was capitalized in 2024, 2023 or 2022. 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	80
Distribution Plant	10	72
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 several 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. We historically tested goodwill for impairment as of December 31st each year; however, in 2024, we elected to change the date of our annual goodwill impairment test to October 1st. We believe this new testing date allows us to better align our annual goodwill impairment testing procedures with our year-end financial reporting, as well as our annual budgeting and forecasting process. This change did not delay, accelerate or avoid the recognition of an impairment charge.

We perform a quantitative impairment assessment, electing to forgo the optional qualitative assessment. 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, 2024 and 2023:

<i>(in thousands)</i>	2024		2023	
Cloud Computing Costs	\$	15,741	\$	12,782
Accumulated Amortization		(3,796)		(1,505)
Cloud Computing Costs, net	\$	11,945	\$	11,277

Amortization expense of capitalized implementation costs for each of the years ended December 31, 2024, 2023 and 2022 totaled \$3.0 million, \$1.3 million, and \$1.4 million.

Leases

We recognize a right-of-use lease asset 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. Certain of our leases contain options to renew or extend the lease term at our discretion if certain conditions are met. 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, or at such time when an event occurs which triggers the remeasurement of a lease, as applicable. In the determination of the lease term for one of our leased manufacturing facilities, we have incorporated the future lease renewals which we believe are reasonably certain to be exercised in the associated right-of-use asset and liability values.

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; such amounts are not incorporated into the measurement of the right-of-use lease asset or lease liability. 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 reference to market interest rates on long-term debt, incorporating considerations of the credit quality of the lessee and the term of lease.

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.

Pension Plans and Other Postretirement Benefits

We maintain pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates. Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

We have elected to apply a minimum amortization method for determining the amount of amortization of net cumulative gains or losses to be included as a component of net periodic benefit cost for any annual period. Cumulative gains and losses recognized in accumulated other comprehensive income or as a deferred regulatory asset or liability that are in excess of 10% of the projected benefit obligation or the market value of pension plan assets are amortized over the expected remaining future service period of active plan participants. In periods in which the cumulative gains and losses do not exceed 10%, no amortization to net period benefit cost is recognized.

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 adjustments 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 within the consolidated statements of income.

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, 2024 and 2023, our liability to participants under these deferred compensation plans was \$29.1 million and \$24.6 million. Company contributions to these plans were \$1.3 million, \$1.2 million and \$0.9 million for the years ended December 31, 2024, 2023 and 2022. Gains or (losses) recognized due to changes in our payment obligations in connection with these plans amounted to (\$3.3 million), (\$3.3 million) and \$3.1 million for the years ended December 31, 2024, 2023 and 2022.

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 OTC's consolidated financial statements. Contribution obligations to the two foundations totaling \$5.5 million and \$5.5 million were recognized as of December 31, 2024 and 2023. Cash contributions paid to the two foundations during the years ended December 31, 2024, 2023 and 2022 were \$5.5 million, \$4.3 million, and \$4.5 million.

Variable Interest Entity

In October 2012, the Coyote Station owners, including OTP, entered into an LSA with Coyote Creek Mining Company, LLC (CCMC), 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, 2024, if recovery of such a loss is denied by regulatory authorities.

Recently Adopted 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. We adopted this updated standard in the 2024 annual period on a retrospective basis, as required by the updated

standard. The adoption of this updated standard resulted in additional disclosures related to our reportable segments and did not have an impact on our consolidated financial position or operating results.

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 2025. The amended guidance is to be applied on a prospective basis with the option to apply the standard retrospectively. We anticipate adopting the updated standard in our Form 10-K for the year ended December 31, 2025 and electing to apply the standard on a retrospective basis for all periods presented.

Disaggregated Income Statement Expenses. In November 2024, the FASB issued authoritative guidance codified in ASC 220, Income Statement—Reporting Comprehensive Income, which will require additional disclosure of certain costs and expenses within the notes to the financial statements. The updated standard is effective for our annual periods beginning in 2027 and interim periods beginning in the first quarter of fiscal 2028 and can be applied on either a prospective or retrospective basis. Early adoption is permitted. We are currently evaluating the impact that the updated standard will have on our financial statement disclosures.

2. Segment Information

Our business is comprised of three reportable segments, Electric, Manufacturing and Plastics, consistent with our business strategy, organizational structure and our internal reporting and review processes. Our chief operating decision maker (CODM) is our Chief Executive Officer. Segment net income is the sole measure of segment profit or loss used by our CODM in assessing segment performance and allocating resources to our segments. Our CODM uses segment net income in assessing financial performance on a monthly basis, reviewing and approving annual operating budgets and periodic forecasts, allocating capital or financial resources to our segments, making strategic decisions and measuring returns on equity in comparison to internal thresholds or peer entities.

The operations of our three reportable segments are further described below. We have aggregated two operating segments within our Manufacturing reportable segment based on the similarity between these businesses and their economic characteristics.

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.

Segment Profit or Loss

Information about each segment, including significant expenses and net income of each segment, for the years ended December 31, 2024, 2023 and 2022 are as follows:

Electric Segment

<i>(in thousands)</i>	2024		2023		2022	
Operating Revenue	\$	524,515	\$	528,359	\$	549,699
Production Fuel and Purchased Power		122,506		138,631		165,391
Operating and Maintenance Expenses		190,422		191,263		181,378
Depreciation and Amortization		82,136		75,330		72,050
Property Taxes		15,662		16,614		17,742
Interest Expense		38,216		33,864		31,950
Income Tax Expense (Benefit)		(1,544)		1,648		5,065
Other Segment Items ⁽¹⁾		(13,846)		(13,415)		(3,851)
Net Income	\$	90,963	\$	84,424	\$	79,974

⁽¹⁾ Other segment items includes nonservice components of postretirement benefits, allowance for funds used during construction, and other expenses (income).

Manufacturing Segment

<i>(in thousands)</i>	2024	2023	2022
Operating Revenue	\$ 342,592	\$ 402,781	\$ 397,983
Cost of Goods Sold	283,390	324,245	327,228
Selling, General, and Administrative Expenses	40,110	49,396	41,690
Interest Expense	2,516	2,295	2,796
Income Tax Expense	2,895	5,390	5,321
Other Segment Items	—	1	(2)
Net Income	\$ 13,681	\$ 21,454	\$ 20,950

Plastics Segment

<i>(in thousands)</i>	2024	2023	2022
Operating Revenue	\$ 463,441	\$ 418,026	\$ 512,527
Cost of Goods Sold	166,628	143,521	227,571
Selling, General, and Administrative Expenses	24,908	20,103	20,378
Interest Expense	590	602	585
Income Tax Expense	70,644	66,066	68,688
Other Segment Items	(76)	(14)	(69)
Net Income	\$ 200,747	\$ 187,748	\$ 195,374

Capital Expenditures and Identifiable Assets

The following provides capital expenditures for each reportable segment and our corporate cost center for the years ended December 31, 2024, 2023 and 2022:

<i>(in thousands)</i>	2024	2023	2022
Capital Expenditures			
Electric	301,454	240,695	147,869
Manufacturing	32,159	23,284	17,954
Plastics	24,749	23,029	5,245
Corporate	288	126	66
Total	\$ 358,650	\$ 287,134	\$ 171,134

The following provides the identifiable assets by segment and corporate assets as of December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Identifiable Assets		
Electric	\$ 2,785,522	\$ 2,533,831
Manufacturing	254,445	251,343
Plastics	186,043	164,179
Corporate	426,072	293,215
Total	\$ 3,652,082	\$ 3,242,568

Corporate assets consist primarily of cash and cash equivalents, prepaid expenses, investments and fixed assets.

Reconciliation to Consolidated Amounts

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

Included below is a reconciliation of certain segment information and our unallocated corporate costs to consolidated amounts for the years ended December 31, 2024, 2023 and 2022:

<i>(in thousands)</i>	2024	2023	2022
Depreciation and Amortization			
Electric	\$ 82,136	\$ 75,330	\$ 72,050
Manufacturing	20,393	18,495	16,202
Plastics	4,494	4,027	4,205
Corporate	98	102	140
Total	107,121	97,954	92,597
Interest Expense			
Total Interest Expense of Reportable Segments	41,322	36,761	35,331
Corporate Interest Expense	493	916	685
Total	41,815	37,677	36,016
Income Tax Expense (Benefit)			
Total Income Tax Expense of Reportable Segments	71,995	73,104	79,074
Corporate Income Tax Benefit	(6,765)	(3,806)	(5,723)
Total	65,230	69,298	73,351
Net Income (Loss)			
Total Net Income of Reportable Segments	305,391	293,626	296,298
Corporate Net Income (Loss)	(3,729)	565	(12,114)
Total	301,662	294,191	284,184

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 2024 we sourced all of our PVC resin needs from four 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.

For the year ended December 31, 2024, two customers combined accounted for 19% of Electric segment operating revenues, two customers combined to account for 36% of Manufacturing segment operating revenues and two customers combined to account for 52% of Plastics segment operating revenues, with one of those customers providing 11% of our consolidated operating revenues.

Entity-Wide Information

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, 2024, 2023 and 2022:

<i>(in thousands)</i>	2024	2023	2022
Operating Revenues			
Electric Segment			
Retail: Residential	\$ 133,408	\$ 135,570	\$ 143,888
Retail: Commercial and Industrial	311,968	312,551	318,494
Retail: Other	7,838	7,719	7,918
Total Retail	453,214	455,840	470,300
Transmission	53,517	52,555	52,213
Wholesale	11,077	12,459	18,539
Other	6,707	7,505	8,647
Total Electric Segment	524,515	528,359	549,699
Manufacturing Segment			
Metal Parts and Tooling	303,077	351,267	338,865
Plastic Products and Tooling	32,210	41,395	49,080
Scrap Metal	7,305	10,119	10,038
Total Manufacturing Segment	342,592	402,781	397,983
Plastics Segment			
PVC Pipe	463,441	418,026	512,527
Total Operating Revenue	1,330,548	1,349,166	1,460,209
Less: Noncontract Revenues Included Above			
Electric Segment - ARP Revenues	575	(4,310)	(9,266)
Total Operating Revenues from Contracts with Customers	\$ 1,329,973	\$ 1,353,476	\$ 1,469,475

4. Receivables

Receivables as of December 31, 2024 and 2023 are as follows:

<i>(in thousands)</i>	2024	2023
Receivables		
Trade	\$ 112,169	\$ 129,257
Other	13,799	9,084
Unbilled Receivables	21,916	21,324
Total Receivables	147,884	159,665
Less Allowance for Credit Losses	1,920	2,522
Receivables, net of allowance for credit losses	\$ 145,964	\$ 157,143

The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Beginning Balance	\$ 2,522	\$ 1,648
Additions Charged to Expense	1,242	2,014
Reductions for Amounts Written Off, Net of Recoveries	(1,844)	(1,140)
Ending Balance	\$ 1,920	\$ 2,522

5. Investments

The following is a summary of our investments as of December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Short-term Investments		
Government Debt Securities	\$ 753	\$ —
Long-term Investments		
Corporate-Owned Life Insurance Policies	47,895	42,287
Government Debt Securities	60,378	7,724
Corporate Debt Securities	1,628	1,579
Mutual Funds	10,653	7,771
Money Market Funds	596	3,125
Other Investments	27	30
Total Long-term Investments	121,177	62,516
Total Investments	\$ 121,930	\$ 62,516

In April 2024, we made a \$50.1 million investment in U.S. treasuries which mature in September 2026. As of December 31, 2024, our government and corporate debt securities had maturity dates ranging from May 2025 to August 2029. During the years ended December 31, 2024 and 2023, our investment income, which consisted primarily of interest on our cash equivalent and debt security investments and gains on our corporate-owned life insurance policy investments, totaled \$19.8 million and \$15.2 million, which is included in other income in our consolidated statements of income.

Debt Securities

The following table summarizes the amortized cost and fair value of debt securities available for sale and the corresponding amounts of gross unrealized gains and losses as of December 31, 2024:

<i>(in thousands)</i>	December 31, 2024			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized (Losses)	Fair Value
Government Debt Securities	\$ 60,891	\$ 424	\$ (184)	\$ 61,131
Corporate Debt Securities	1,629	9	(10)	1,628
Total	\$ 62,520	\$ 433	\$ (194)	\$ 62,759

Unrealized gains and losses on available-for-sale debt securities as of December 31, 2023 were not material. As of December 31, 2024 and December 31, 2023, no unrealized losses on debt securities were deemed to be other-than-temporary.

The following table summarizes the fair value of debt securities available for sale by contractual maturity date as of December 31, 2024:

<i>(in thousands)</i>	December 31, 2024
Due in one year or less	\$ 753
Due in one to five years	62,006
Total	\$ 62,759

Equity Securities

The amount of net unrealized gains and losses during the years ended December 31, 2024 and 2023 on marketable equity securities still held as of December 31, 2024 and 2023, respectively, was not material.

6. Regulatory Matters

Regulatory Assets and Liabilities

The following presents our current and long-term regulatory assets and liabilities as of December 31, 2024 and 2023 and the period we expect to recover or refund such amounts:

(in thousands)	Period of Recovery/	2024		2023	
		Current	Long-Term	Current	Long-Term
Regulatory Assets					
Pension and Other Postretirement Benefit Plans ¹	See below	\$ —	\$ 88,161	\$ 154	\$ 86,134
Alternative Revenue Program Riders ²	Up to 2 years	4,257	195	3,719	158
Deferred Income Taxes	Asset lives	—	8,944	—	6,940
Fuel Clause Adjustments ¹	Up to 1 year	2,218	—	7,294	—
Derivative Instruments ¹	Up to 1 year	1,989	—	4,210	—
Other ¹	Various	1,498	1,373	750	2,483
Total Regulatory Assets		9,962	98,673	16,127	95,715
Regulatory Liabilities					
Deferred Income Taxes	Asset lives	—	130,387	—	136,022
Plant Removal Obligations	Asset lives	—	126,263	—	117,030
Fuel Clause Adjustments	Up to 1 year	11,432	—	11,350	—
Alternative Revenue Program Riders	Up to 1 year	14,255	—	6,885	—
North Dakota PTC Refunds	Asset lives	—	20,099	—	12,011
Pension and Other Postretirement Benefit Plans	See below	2,547	10,758	6,138	11,307
Other	Various	1,073	1,421	1,035	177
Total Regulatory Liabilities		\$ 29,307	\$ 288,928	\$ 25,408	\$ 276,547

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 collected from customers that are subject to refund, respectively, primarily due to investments in qualifying transmission, conservation, renewable resource, environmental and other generation assets, and the impact of decoupling.

Deferred Income Taxes primarily 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 in future periods.

Derivative Instruments represent unrealized losses recognized on derivative instruments. On final settlement of such instruments, any realized losses are 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 from our wind energy facilities. These amounts are being allocated to customers over the lives of the assets generating the credits.

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 ROE of 10.6% on an equity ratio of 53.5% of total capital. The filing also 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. Interim rates went into effect on January 1, 2024. On July 3, 2024, OTP filed an update to the original request increasing the amount of the net annual revenue requirement from \$17.4 million to \$22.5 million, or a net increase of 10.9% in annual revenue, to account for certain items identified throughout the regulatory process.

On December 30, 2024, the NDPSC approved a settlement agreement between OTP and certain interested parties in the general rate case and issued its written order on final rates. The key provisions of the order include a revenue requirement of \$225.6 million, based on a return on rate base of 7.53%, and an allowed ROE of 10.10% on an equity ratio of 53.5%. The net annual revenue requirement includes a net increase of \$13.1 million, or 6.18%. OTP's revenue requirement was reduced by approximately

\$3.0 million primarily due to the inclusion of forecasted PTCs plus adjustments for new customer load additions, which were not included in OTP's updated request filed on July 3, 2024. Through the settlement of the case, the parties also agreed to establish an earnings sharing mechanism, whereby 70% of actual earnings in excess of a 10.20% ROE would be returned to customers, with OTP retaining the remaining 30%.

7. Property, Plant and Equipment

Major classes of property, plant and equipment as of December 31, 2024 and 2023 include:

<i>(in thousands)</i>	<i>2024</i>		<i>2023</i>	
Electric Plant in Service				
Production	\$	1,469,008	\$	1,412,826
Transmission		820,415		777,613
Distribution		726,159		654,704
General		165,361		144,738
Electric Plant in Service		3,180,943		2,989,881
Construction Work in Progress		231,890		137,212
Total Gross Electric Plant		3,412,833		3,127,093
Less Accumulated Depreciation		899,049		851,148
Net Electric Plant		2,513,784		2,275,945
Nonelectric Property, Plant and Equipment				
Equipment		260,307		233,571
Buildings and Leasehold Improvements		88,680		64,753
Land		13,578		13,600
Nonelectric Property, Plant and Equipment		362,565		311,924
Construction Work in Progress		40,536		38,062
Total Gross Nonelectric Property, Plant and Equipment		403,101		349,986
Less Accumulated Depreciation		224,425		207,556
Net Nonelectric Property, Plant and Equipment		178,676		142,430
Net Property, Plant and Equipment	\$	2,692,460	\$	2,418,375

Depreciation expense for the years ended December 31, 2024, 2023 and 2022 totaled \$99.4 million, \$90.8 million and \$84.4 million.

The following table provides OTP's ownership percentages and amounts included in the December 31, 2024 and 2023 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, 2024					
Big Stone Plant	53.9 %	\$ 345,990	\$ 459	\$ (135,065)	\$ 211,384
Coyote Station	35.0 %	188,066	813	(118,268)	70,611
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(8,445)	97,740
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(12,247)	65,937
Big Stone South–Brookings 345 kV line	50.0 %	53,167	—	(5,822)	47,345
Brookings–Southeast Twin Cities 345 kV line	4.8 %	28,013	1,131	(3,941)	25,203
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,693)	12,638
Jamestown– Ellendale 345 kV line	50.0 %	—	5,509	—	5,509
Big Stone South–Alexandria 345 kV line	40.0 %	—	2,418	—	2,418
Alexandria–Big Oaks 345 kV line	14.2 %	—	417	—	417
Oslo - Lake Ardoch 115 kV line	72.0 %	—	2,646	—	2,646
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

8. Intangible Assets

The following table summarizes our goodwill by segment as of December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
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 2024 and 2023, indicated no impairment existed as of the test date.

The following table summarizes the components of our intangible assets as of December 31, 2024 and 2023:

<i>(in thousands)</i>	<i>Gross Amount</i>	<i>Accumulated Amortization</i>	<i>Net Carrying Amount</i>
December 31, 2024			
Customer Relationships	\$ 22,491	\$ 16,766	\$ 5,725
Other	26	8	18
Total	\$ 22,517	\$ 16,774	\$ 5,743
December 31, 2023			
Customer Relationships	\$ 22,491	\$ 15,667	\$ 6,824
Other	26	7	19
Total	\$ 22,517	\$ 15,674	\$ 6,843

Amortization expense for these intangible assets for each of the years ended December 31, 2024, 2023 and 2022 totaled \$1.1 million.

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

<i>(in thousands)</i>		2025		2026		2027		2028		2029
Amortization Expense	\$	1,100	\$	1,092	\$	1,090	\$	554	\$	285

9. 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, 2024, 2023, and 2022 are as follows:

<i>(in thousands)</i>		2024		2023		2022
Lease Cost						
Operating Lease Cost	\$	6,688	\$	6,309	\$	5,606
Variable Lease Cost		1,460		1,433		1,386
Short-Term Lease Cost		2,746		2,525		1,517
Total Lease Cost	\$	10,894	\$	10,267	\$	8,509
Lease Cash Flows						
Operating Cash Flows from Operating Leases	\$	6,762	\$	6,424	\$	5,592

A summary of operating lease right-of-use lease assets and lease liabilities as of December 31, 2024 and 2023 is as follows:

<i>(in thousands)</i>		2024		2023
Right of Use Lease Assets ¹	\$	28,179	\$	16,788
Lease Liabilities				
Current ²		4,776		5,756
Long-Term ³		23,567		11,258
Total Lease Liabilities	\$	28,343	\$	17,014

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 lease liabilities amounted to \$17.6 million and \$3.6 million for the years ended December 31, 2024 and 2023.

Maturities of lease liabilities as of December 31, 2024 for each of the next five years and in the aggregate thereafter are as follows:

<i>(in thousands)</i>		Operating Leases
2025	\$	6,350
2026		5,638
2027		4,785
2028		3,604
2029		2,750
Thereafter		12,921
Total Lease Payments		36,048
Less: Interest		7,705
Present Value of Lease Liabilities	\$	28,343

The weighted-average remaining lease term and the weighted-average discount rate as of December 31, 2024 and 2023 are as follows:

	2024	2023
Weighted-Average Remaining Lease Term (in years)	7.9	3.4
Weighted-Average Discount Rate	6.37 %	5.40 %

10. 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, 2024 and 2023:

(in thousands)	2024			2023		
	OTC	OTP	Total	OTC	OTP	Total
Short-Term Debt	\$ —	\$ 69,615	\$ 69,615	\$ —	\$ 81,422	\$ 81,422
Long-Term Debt	79,900	863,834	943,734	79,849	744,210	824,059
Total	\$ 79,900	\$ 933,449	\$ 1,013,349	\$ 79,849	\$ 825,632	\$ 905,481

Short-Term Debt

The following is a summary of our lines of credit as of December 31, 2024 and 2023:

(in thousands)	Line Limit	2024		2023	
		Amount Outstanding	Letters of Credit	Amount Available	Amount Available
OTC Credit Agreement	\$ 170,000	\$ —	\$ —	\$ 170,000	\$ 170,000
OTP Credit Agreement	220,000	69,615	8,772	141,613	79,446
Total	\$ 390,000	\$ 69,615	\$ 8,772	\$ 311,613	\$ 249,446

On December 11, 2024, OTC entered into a Sixth Amended and Restated Credit Agreement (the OTC Credit Agreement) and OTP entered into a Fifth Amended and Restated Credit Agreement (the OTP Credit Agreement), in each case amending and restating the previously existing credit agreements, to extend the maturity date of each credit facility and adjust the maximum debt to total capitalization covenant. The OTP Credit Agreement was also amended to increase the maximum borrowing capacity. The OTC agreement provides for a \$170.0 million unsecured revolving line of credit and the OTP agreement provides for a \$220.0 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 \$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 \$300.0 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, 2024 and 2023 was 5.61% and 6.70%.

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 includes a cross-default provision whereby an event of default of other outstanding indebtedness will trigger an event of default under the agreement. Each credit facility expires on December 11, 2029.

Long-Term Debt

The following is a summary of outstanding long-term debt by borrower as of December 31, 2024 and 2023:

Entity	Debt Instrument	Rate	Maturity	(in thousands)	
				2024	2023
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 2024A Senior Unsecured Notes	5.48%	04/01/34	60,000	—
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
OTP	Series 2024B Senior Unsecured Notes	5.77%	04/01/54	60,000	—
Total				947,000	827,000
Less: Unamortized Long-Term Debt Issuance Costs				3,266	2,941
Total Long-Term Debt Net of Unamortized Debt Issuance Costs				\$ 943,734	\$ 824,059

On March 28, 2024, OTP entered into a Note Purchase Agreement pursuant to which OTP issued, in a private placement transaction, \$120.0 million of senior unsecured notes consisting of (a) \$60.0 million of 5.48% Series 2024A Senior Unsecured Notes due April 1, 2034, and (b) \$60.0 million of 5.77% Series 2024B Senior Unsecured Notes due April 1, 2054.

Per the terms of the agreement, OTP may prepay all or any part of the notes (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount, as defined in the agreement; provided that no default or event of default exists under the agreement. Any prepayment of the Series 2024A Notes then outstanding on or after January 1, 2034, or the Series 2024B Notes then outstanding on or after October 1, 2053, will be made without any make-whole amount. Consistent with other of our borrowings, the agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell substantially all assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in certain transactions with affiliates.

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. The notes include a cross-default provision whereby an event of default of other outstanding indebtedness will trigger an event of default under the note.

Aggregate maturities of long-term debt obligations on December 31, 2024 for each of the next five years are as follows:

(in thousands)	2025		2026		2027		2028		2029
Debt Maturities	\$	—	\$	80,000	\$	42,000	\$	—	\$ 70,000

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 either 0.60 to 1.00 or 0.65 to 1.00, depending on the debt agreement, a minimum interest and dividend coverage ratio of 1.50 to 1.00, and a maximum level of priority indebtedness. As of December 31, 2024, 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, BTD Manufacturing, Inc., Northern Pipe Products, Inc. and Vinyltech Corporation.

11. 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, 2024 and 2023:

<i>Asset Class</i>	Permitted Range	Actual Allocation	
		2024	2023
Return Enhancement	35 – 60%	41 %	48 %
Risk Management	40 – 80%	59	51
Alternatives	0 – 20%	—	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, 2024 and 2023 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, 2024					
Equity Funds	\$ 116,889	\$ —	\$ —	\$ —	\$ 116,889
Fixed Income Funds	175,310	—	—	—	175,310
Hybrid Funds	10,106	—	—	—	10,106
U.S. Treasury Securities	23,909	—	—	—	23,909
SEI Energy Debt Collective Fund	—	—	—	1,061	1,061
Total	\$ 326,214	\$ —	\$ —	\$ 1,061	\$ 327,275
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

The investments held by the SEI Energy Debt Collective Fund on December 31, 2024 and 2023 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, 2024 and 2023 and the funded status of the plans as of December 31, 2024 and 2023:

(in thousands)	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2024	2023	2024	2023	2024	2023
Change in Fair Value of Plan Assets:						
Fair Value of Plan Assets at January 1	\$ 330,479	\$ 313,797	\$ —	\$ —	\$ —	\$ —
Actual Return on Plan Assets	14,976	34,196	—	—	—	—
Company Contributions	—	—	2,694	2,197	1,568	3,167
Benefit Payments	(18,180)	(17,514)	(2,694)	(2,197)	(3,734)	(8,900)
Participant Premium Payments	—	—	—	—	2,166	5,733
Fair Value of Plan Assets at December 31	\$ 327,275	\$ 330,479	\$ —	\$ —	\$ —	\$ —
Change in Benefit Obligation:						
Benefit Obligation at January 1	\$ 318,801	\$ 308,055	\$ 35,780	\$ 35,624	\$ 30,145	\$ 49,947
Service Cost	3,886	3,698	—	72	490	565
Interest Cost	17,189	16,436	1,897	1,889	1,600	2,416
Benefit Payments	(18,180)	(17,514)	(2,694)	(2,197)	(3,734)	(8,900)
Participant Premium Payments	—	—	—	—	2,166	5,733
Plan Amendments	—	—	—	—	—	(17,493)
Actuarial (Gain) Loss	(7,686)	8,126	331	392	(664)	(2,123)
Benefit Obligation at December 31	314,010	318,801	35,314	35,780	30,003	30,145
Funded Status	\$ 13,265	\$ 11,678	\$ (35,314)	\$ (35,780)	\$ (30,003)	\$ (30,145)
Amounts Recognized in Consolidated Balance Sheets at December 31:						
Noncurrent Assets	\$ 13,265	\$ 11,678	\$ —	\$ —	\$ —	\$ —
Current Liabilities	—	—	(2,700)	(2,679)	(2,618)	(2,469)
Noncurrent Liabilities	—	—	(32,614)	(33,101)	(27,385)	(27,676)
Net Asset (Liability)	\$ 13,265	\$ 11,678	\$ (35,314)	\$ (35,780)	\$ (30,003)	\$ (30,145)

The accumulated benefit obligation of our Pension Plan was \$288.5 million and \$288.8 million as of December 31, 2024 and 2023.

The accumulated benefit obligation of our ESSRP was \$35.3 million and \$35.8 million as of December 31, 2024 and 2023.

The following assumptions were used to determine benefit obligations as of December 31, 2024 and 2023:

	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2024	2023	2024	2023	2024	2023
Discount Rate	5.70 %	5.57 %	5.60 %	5.53 %	5.61 %	5.53 %
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 %	4.50 %	n/a	n/a	n/a	n/a
Participants Age 50 and Older ⁽³⁾	3.75 %	3.75 %	n/a	n/a	n/a	n/a
Healthcare Cost Immediate Trend Rate	n/a	n/a	n/a	n/a	6.44 %	6.97 %
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 2024 and 2023 reduced our obligation by \$4.7 million and \$2.2 million. Changes in plan participant census data decreased our benefit obligation by \$3.0 million in 2024. Actual

returns on Pension Plan assets in 2024 were \$15.0 million, compared to an expected return of \$25.5 million, impacting our net obligation by \$10.5 million.

- For the ESSRP, an increase in the discount rate in 2024 and 2023 reduced our obligation by \$0.2 million and \$0.1 million.
- For the postretirement healthcare plan, an increase in the discount rate in 2024 and 2023 reduced our obligation by \$0.2 million and \$1.3 million. Revised estimates of healthcare cost trends and participant contribution assumptions increased the benefit obligation by \$0.4 million in 2024. Changes in plan participant census data decreased our benefit obligation by \$0.9 million in 2024.

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, 2024, 2023 and 2022:

(in thousands)	Pension Benefits (Pension Plan)			Pension Benefits (ESSRP)			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022	2024	2023	2022
Service Cost	\$ 3,886	\$ 3,698	\$ 6,576	\$ —	\$ 72	\$ 195	\$ 490	\$ 565	\$ 1,338
Interest Cost	17,189	16,436	12,344	1,897	1,889	1,341	1,600	2,416	2,041
Expected Return on Assets	(25,518)	(25,914)	(23,684)	—	—	—	—	—	—
Amortization of Prior Service Cost	—	—	—	—	—	—	(6,302)	(6,649)	(5,733)
Amortization of Net Actuarial Loss	158	—	7,865	—	—	567	—	—	3,063
Net Periodic Benefit Cost	\$ (4,285)	\$ (5,780)	\$ 3,101	\$ 1,897	\$ 1,961	\$ 2,103	\$ (4,212)	\$ (3,668)	\$ 709

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, 2024, 2023 and 2022:

(in thousands)	2024	2023	2022
Net Periodic Benefit Cost	\$ (6,600)	\$ (7,487)	\$ 5,913
Net Amount Amortized Due to the Effect of Regulation	1,367	1,225	1,121
Net Periodic Benefit Cost Recognized	\$ (5,233)	\$ (6,262)	\$ 7,034

The following assumptions were used to determine net periodic benefit cost for the years ended December 31, 2024, 2023 and 2022:

	Pension Benefits (Pension Plan)			Pension Benefits (ESSRP)			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022	2024	2023	2022
Discount Rate	5.57 %	5.51 %	3.03 %	5.53 %	5.51 %	2.93 %	5.53 %	5.52 %	3.01 %
Long-Term Rate of Return on Plan Assets	7.00 %	7.00 %	6.30 %	n/a	n/a	n/a	n/a	n/a	n/a
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	4.00 %	3.50 %	3.50 %	n/a	n/a	n/a	n/a	n/a	n/a
Participants Age 50 and Older	3.38 %	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, 2024 and 2023:

(in thousands)	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2024	2023	2024	2023	2024	2023
Regulatory Assets (Liabilities):						
Unrecognized Prior Service Cost	\$ —	\$ —	\$ —	\$ —	\$ (12,703)	\$ (18,845)
Unrecognized Actuarial Loss	87,868	85,227	292	1,061	1,121	1,759
Net Regulatory Assets (Liabilities)	\$ 87,868	\$ 85,227	\$ 292	\$ 1,061	\$ (11,582)	\$ (17,086)
Accumulated Other Comprehensive Income (Loss):						
Unrecognized Prior Service Cost	\$ —	\$ —	\$ —	\$ —	\$ 339	\$ 498
Unrecognized Actuarial Gain (Loss)	1,937	1,994	(2,502)	(1,403)	732	707
Total Accumulated Other Comprehensive Income (Loss)	\$ 1,937	\$ 1,994	\$ (2,502)	\$ (1,403)	\$ 1,071	\$ 1,205

Cash Flows. We did not make any contributions to our Pension Plan in 2024 or 2023. We made a discretionary contribution of \$20.0 million in 2022. As of December 31, 2024, 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)	2025	2026	2027	2028	2029	2030-2034
Projected Pension Plan Benefit Payments	\$ 19,274	\$ 19,804	\$ 20,284	\$ 20,859	\$ 21,420	\$ 111,275
Projected ESSRP Benefit Payments	2,769	2,899	3,059	2,999	3,070	14,275
Projected Postretirement Benefit Payments	2,618	2,614	2,576	2,488	2,517	12,019
Total	\$ 24,661	\$ 25,317	\$ 25,919	\$ 26,346	\$ 27,007	\$ 137,569

401K Plan

We sponsor a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans totaled \$9.3 million for 2024, \$7.8 million for 2023 and \$6.7 million for 2022.

12. 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 or removal 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, 2024 and 2023, \$0.1 million and \$0.1 million, respectively, was included in other current liabilities and \$42.1 million and \$36.4 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, 2024 and 2023 is as follows:

(in thousands)	2024	2023
Beginning Balance	\$ 36,477	\$ 25,182
New Obligations Recognized	2,991	4,506
Adjustments Due to Revisions in Cash Flow Estimates	1,098	8,394
Accrued Accretion	1,676	1,191
Settlements	(79)	(2,796)
Ending Balance	\$ 42,163	\$ 36,477

Coal Combustion Residual Regulations

In May 2024, the Environmental Protection Agency (EPA) published a final rule amending coal combustion residual (CCR) regulations. The final rule introduces new requirements for the management of coal ash at active coal-fired power plants and inactive coal-fired

power plants with a legacy surface impoundment. The regulations impose new requirements including groundwater monitoring, closure standards, post-closure care obligations and potential remediation activities. At this time, we do not believe there are any significant new requirements which are applicable to our coal-fired power plants, except for Big Stone Plant. During the fourth quarter of 2024, a site evaluation was performed at Big Stone Plant to assess the presence and estimated volumes of coal ash stored at the facility. Based on this and our assessment of the regulations, we believe the plant will be impacted by the new requirements. As of December 31, 2024, we recognized \$3.0 million of additional liabilities for new obligations resulting from the EPA's final CCR rule for costs associated with coal ash removal and groundwater monitoring we expect to incur in the future. The final rule requires facility evaluations to be performed in the future. Revisions to our estimated compliance costs or further obligations could be identified through the process of performing the additional evaluations. Should such revisions be necessary or if additional cost obligations are identified, we will update our cash flow estimates and resulting retirement obligation at that time.

13. Income Taxes

Income before income taxes for the years ended December 31, 2024, 2023 and 2022 consists entirely of domestic earnings.

The provision for income taxes charged to income for the years ended December 31, 2024, 2023 and 2022 consisted of the following:

<i>(in thousands)</i>	2024		2023		2022	
Current						
Federal Income Taxes	\$	36,238	\$	41,253	\$	31,949
State Income Taxes		6,533		15,126		9,568
Deferred						
Federal Income Taxes		13,078		9,832		22,480
State Income Taxes		9,979		3,676		9,943
Tax Credits						
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		(586)		(586)		(586)
Investment Tax Credit Amortization		(12)		(3)		(3)
Total	\$	65,230	\$	69,298	\$	73,351

The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2024, 2023 and 2022 is as follows:

	2024		2023		2022	
Income Taxes at Federal Statutory Rate	\$	77,047	21.0 %	\$	76,332	21.0 %
Increases (Decreases) in Tax from:						
State Taxes on Income, Net of Federal Tax		14,360	3.9		14,429	4.0
Production Tax Credits (PTCs)		(20,106)	(5.5)		(17,394)	(4.8)
Amortization of Excess Deferred Income Taxes		(2,788)	(0.8)		(2,205)	(0.6)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		(586)	(0.2)		(586)	(0.2)
Other, Net		(2,697)	(0.6)		(1,278)	(0.3)
Income Taxes at Effective Tax Rate	\$	65,230	17.8 %	\$	69,298	19.1 %
					\$	73,351
						20.5 %

PTCs, North Dakota wind tax credits and excess deferred income taxes arising from 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, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Deferred Tax Assets		
Employee Benefits	\$ 37,456	\$ 39,959
Regulatory Liabilities	52,664	56,479
Tax Credit Carryforwards	18,268	21,836
Cost of Removal	35,374	32,993
Asset Retirement Obligations	10,948	9,494
Net Operating Loss Carryforward	2,289	2,336
Other	19,449	11,310
Total Deferred Tax Assets	\$ 176,448	\$ 174,407
Deferred Tax Liabilities		
Differences Related to Property	\$ (375,120)	\$ (347,885)
Retirement Benefits Regulatory Asset	(22,892)	(22,458)
Pension Expense	(26,034)	(24,875)
Other	(20,147)	(16,462)
Total Deferred Tax Liabilities	(444,193)	(411,680)
Deferred Income Taxes	\$ (267,745)	\$ (237,273)

As of December 31, 2024, we had net operating loss carryforwards for state tax purposes totaling \$2.3 million that expire between 2029 and 2037, and state tax credits totaling \$18.3 million which expire between 2040 and 2043.

The following table summarizes the activity for unrecognized tax benefits for the years ended December 31, 2024, 2023 and 2022:

<i>(in thousands)</i>	2024	2023	2022
Balance on January 1	\$ 1,489	\$ 923	\$ 827
Increases (Decreases) for tax positions taken during a prior period	(189)	596	44
Increases for tax positions taken during the current period	188	163	260
Decreases due to settlements with taxing authorities	—	—	—
Decreases as a result of a lapse of applicable statutes of limitations	(363)	(193)	(208)
Balance on December 31	\$ 1,125	\$ 1,489	\$ 923

The balance of unrecognized tax benefits as of December 31, 2024 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2024 is not expected to change significantly within the next 12 months.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2024, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2021 for federal and North Dakota income taxes and prior to 2020 for Minnesota state income taxes.

14. Commitments and Contingencies

Commitments

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, but do not include fixed or minimum payments. The required payments are variable and the amounts due are determined based upon the amount of capacity available or electricity generated. Capacity and energy requirement costs under these agreements totaled \$6.0 million, \$5.6 million and \$13.1 million for the years ended December 31, 2024, 2023 and 2022.

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 on 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, 2026. 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 \$44.7 million, \$43.7 million and \$45.1 million for the years ended December 31, 2024, 2023 and 2022.

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 \$62.0 million. Land easement costs under these agreements totaled \$1.8 million, \$1.8 million and \$1.4 million for the years ended December 31, 2024, 2023 and 2022.

Other Commitments. As of December 31, 2024, we had commitments under contracts for plant maintenance, software subscriptions and other services extending into 2046 which totaled approximately \$10.6 million.

Our future commitments as of December 31, 2024 were as follows:

<i>(in thousands)</i>	<i>Coal Purchase Commitments</i>	<i>Land Easement Payments</i>	<i>Other Commitments</i>
2025	\$ 24,192	\$ 1,897	\$ 1,817
2026	24,416	1,902	1,518
2027	25,127	1,941	661
2028	25,859	1,981	544
2029	27,102	2,021	272
Beyond 2029	314,713	52,261	5,758
Total	\$ 441,409	\$ 62,003	\$ 10,570

Solar Development. On October 30, 2024, OTP entered into an agreement to acquire the assets of a solar facility currently under development. The assets to be acquired include real property rights and interests, interconnection agreements, state and local permits, and other development assets. Per the agreement, the purchase price is equal to \$23.6 million, plus the reimbursement of certain interconnection costs and costs to purchase and store the main power transformer. Closing of the transaction is expected to occur in late 2025 or early 2026, and remains subject to certain conditions to close, including regulatory and other approvals. OTP would be subject to a termination fee of up to \$5.0 million if the seller has satisfied all required conditions to close but the transaction is not consummated.

Contingencies

FERC ROE. In November 2013 and February 2015, customers filed complaints with 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 issued an order on November 19, 2020, which 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 and remanded the matter to FERC to reopen the proceedings.

On October 17, 2024, FERC issued an Order on Remand modifying its ROE methodology and establishing a base ROE of 9.98% (10.48% with an adder) effective for the fifteen-month period from November 2013 to February 2015 and on a prospective basis beginning in September 2016, and required MISO transmission owners to provide refunds to customers for collections in excess of the base ROE of 9.98% for the applicable period, plus interest. In addition, FERC concluded the evidentiary record continues to support the ROE established for the period from February 2015 to May 2016.

Prior to FERC's Order on Remand, we had deferred recognition of certain revenues and recognized a refund liability which reflected the amount previously collected under the MISO tariff rate that we anticipated would be refunded to customers. Our previous estimated refund amount was larger than the actual amount ordered by FERC in the Order on Remand and was therefore reduced, which resulted in a pre-tax benefit of \$2.5 million recognized in our consolidated statements of income for the year ended December 31, 2024. The balance of the recorded refund liability as of December 31, 2024 was \$0.5 million.

Self-Funding of Transmission Upgrades for Generator Interconnections. FERC has granted transmission owners within MISO and other regional transmission organizations (RTOs) 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 have 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 proceedings, 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. In December 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.

In June 2024, FERC issued an Order to Show Cause proceeding against four RTOs, including MISO. Within its order, FERC indicates that the transmission tariffs of the RTOs appear to be unjust, unreasonable, and unduly discriminatory or preferential because they allow transmission owners to unilaterally elect transmission owner self-funding, which may increase costs, impose barriers to transmission interconnection and result in undue discrimination among interconnection customers.

The order required each RTO to submit filings to either 1) show cause as to why the transmission tariff remains just and reasonable and not unduly discriminatory or preferential, or 2) to explain what changes to the tariff it believes would remedy the identified concerns. FERC has received a number of responses to its Order to Show Cause. In September 2024, in separate filings, MISO and transmission owners within MISO, including OTP, filed responses outlining the reasons why the self-funding option remains just and reasonable and not unduly discriminatory or preferential. Other responses have been provided by other RTOs, individual transmission owners, developers of renewable generation facilities and other interested parties.

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 the resolution of this matter 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 FERC may ultimately decide on the matter after RTOs' filings in response to the Order to Show Cause.

Class Action Lawsuits. Several class action complaints against certain PVC pipe manufacturers, including OTC, have been filed in the U.S. District Court for the Northern District of Illinois alleging violations of antitrust laws. The first of the complaints was filed on August 23, 2024. The various complaints have been consolidated under the caption *In re: PVC Pipe Antitrust Litigation* (Case No. 1:24-cv-07639). Specifically, the complaints allege, among other things, that beginning in at least January 2021, the defendants conspired and combined to fix, raise, maintain and stabilize the price of PVC municipal water and electrical conduit pipe in violation of U.S. antitrust laws. The plaintiffs are seeking treble damages, injunctive relief, pre- and post-judgment interest, costs and attorneys' fees.

In addition, on August 27, 2024, the Company received a grand jury subpoena issued by the U.S. District Court for the Northern District of California, from the U.S. Department of Justice (DOJ) Antitrust Division. The subpoena calls for production of documents regarding the manufacturing, selling and pricing of PVC pipe. The Company is responding to the subpoena and intends to comply with its obligations under the subpoena.

At this time, we are unable to determine the likelihood of an outcome or estimate a range of reasonably possible losses, if any, arising from the class action complaints or the DOJ investigation. However, if an antitrust violation by the Company is found, it could have a material impact on the Company's financial condition, operating results and liquidity. The Company believes that there are factual and legal defenses to the allegations in the complaints and intends to defend itself accordingly.

Other Contingencies. We are party to litigation and regulatory matters arising in the normal course of business. We regularly analyze relevant information and, as necessary, estimate and record accrued liabilities for legal, regulatory enforcement and other 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, 2024, other than those discussed above, will not be material.

15. 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, 2024 or 2023.

Registration Statements

On May 3, 2024, 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 2027. No shares were issued pursuant to the shelf registration statement in 2024.

On May 3, 2024, 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 methods 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. In 2024, we issued 70,469 common shares under this program and no proceeds were received, as all shares issued were purchased on the open market. As of December 31, 2024, 1,429,531 shares remained available for purchase or issuance under the plan. The registration statement expires in May 2027.

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, as further described below:

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, 2024, we were in compliance with these financial covenants.

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

The MPUC indirectly limits the amount of dividends OTP can pay to OTC by requiring an equity-to-total-capitalization ratio between 47.2% and 57.7%, with total capitalization not to exceed \$2.2 billion based on OTP's capital structure requirements as of December 31, 2024. As of December 31, 2024, OTP's equity-to-total-capitalization ratio including short-term debt was 53.1% and its net assets restricted from distribution totaled approximately \$834.5 million.

16. 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 statements 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, 2024, 2023 and 2022:

<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, 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
Other Comprehensive Income Before Reclassifications, net of tax	501	407	908
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1,503) ⁽¹⁾	(21) ⁽²⁾	(1,524)
Total Other Comprehensive Income (Loss)	(1,002)	386	(616)
Balance, December 31, 2024	\$ 373	\$ 159	\$ 532

⁽¹⁾ Included in the computation of net periodic pension and other postretirement benefit costs. See Note 11 for further information.

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

17. 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 \$0.4 million, \$0.3 million and \$0.3 million for the years ended December 31, 2024, 2023 and 2022. For the years ended December 31, 2024, 2023 and 2022, the amount of shares issued under the plan amounted to 31,252, 26,348 and 26,420 shares. As of December 31, 2024, there were 206,115 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, 2024, 828,761 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 \$9.1 million, \$7.4 million and \$6.6 million for the years ended December 31, 2024, 2023 and 2022. The related income tax benefit recognized for these periods amounted to \$2.7 million, \$1.6 million and \$1.7 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 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, 2024:

	Shares	Average Grant-Date Fair Value
Nonvested, Beginning of Year	148,913	\$ 56.48
Granted	52,425	85.25
Vested	(57,771)	52.78
Forfeited	(150)	66.39
Nonvested, End of Year	143,417	\$ 68.47

The weighted-average grant-date fair value of granted awards was \$85.25, \$68.03 and \$59.95 during the years ended December 31, 2024, 2023 and 2022. The fair value of vested awards was \$5.1 million, \$3.1 million and \$3.0 million during the years ended December 31, 2024, 2023 and 2022. As of December 31, 2024, there was \$3.7 million of unrecognized compensation cost for unvested restricted stock awards to be recognized over a weighted-average period of 1.5 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 number 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, 2024, 2023 and 2022 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, 2024, 2023 and 2022 was determined using a Monte Carlo fair value simulation model incorporating the following assumptions:

	2024	2023	2022
Risk-free interest rate	4.16 %	4.15 %	1.52 %
Expected term (in years)	3.00	3.00	3.00
Expected volatility	35.10 %	34.00 %	32.00 %
Dividend yield	2.40 %	2.50 %	2.90 %

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, 2024 (share amounts reflect awards at target):

	Shares	Average Grant-Date Fair Value
Nonvested, Beginning of Year	194,200	\$ 50.33
Granted	43,400	94.45
Vested	(92,800)	42.06
Forfeited	—	—
Nonvested, End of Year	144,800	\$ 68.85

The weighted-average grant-date fair value of granted awards was \$94.45, \$61.97 and \$54.91 during the years ended December 31, 2024, 2023 and 2022. The fair value of vested awards was \$12.3 million, \$5.3 million and \$5.1 million during the years ended December 31, 2024, 2023 and 2022. As of December 31, 2024, there was \$0.5 million of unrecognized compensation cost of unvested stock performance awards to be recognized over a weighted-average period of 0.65 years.

18. 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, 2024, 2023 and 2022:

<i>(in thousands)</i>	2024	2023	2022
Weighted Average Common Shares Outstanding – Basic	41,778	41,668	41,586
Effect of Dilutive Securities:			
Stock Performance Awards	196	269	248
Restricted Stock Awards	96	100	95
Employee Stock Purchase Plan Shares and Other	2	2	2
Dilutive Effect of Potential Common Shares	294	371	345
Weighted Average Common Shares Outstanding – Diluted	42,072	42,039	41,931

The number 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, 2024, 2023 and 2022.

19. 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 on a gross basis with assets and liabilities presented separately. 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, 2024 and 2023, OTP had multiple outstanding pay-fixed, receive-variable swap agreements. The contracts outstanding as of December 31, 2024 had various settlement dates throughout 2025. The following presents the notional amounts and fair value of our derivative instruments as of December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Megawatt hours of electricity	167	187
Derivative Liabilities:		
Other Current Liabilities	\$ 1,989	\$ 4,210
Other Noncurrent Liabilities	—	—
Total Derivative Liabilities	\$ 1,989	\$ 4,210

During the years ended December 31, 2024 and 2023, contracts matured and were settled in an aggregate amount of a \$3.5 million loss and a \$16.5 million loss, 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 consolidated statements of income, these gains or losses are included in electric purchased power. Gains or losses related to the settlement of derivative instruments are included in cash flows from operations in the consolidated statements of cash flows.

20. Fair Value Measurements

The following tables present our assets and liabilities measured at fair value on a recurring basis as of December 31, 2024 and 2023 classified by the input method used to measure fair value:

	<i>Level 1</i>	<i>Level 2</i>	<i>Level 3</i>
December 31, 2024			
Assets			
Investments:			
Money Market Funds	\$ 596	\$ —	\$ —
Mutual Funds	10,653	—	—
Corporate Debt Securities	—	1,628	—
Government Debt Securities	—	61,131	—
Total Assets	11,249	62,759	—
Liabilities			
Derivative Instruments	—	1,989	—
Total Liabilities	\$ —	\$ 1,989	\$ —

<i>(in thousands)</i>	<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	\$ —

Level 1 fair value measurements are based on quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access at the measurement date.

The level 2 fair value measurements for government and corporate debt securities are determined based on valuations provided by third parties which utilize industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing services 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, 2024 and 2023:

(in thousands)	December 31, 2024		December 31, 2023	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and Cash Equivalents	\$ 294,651	\$ 294,651	\$ 230,373	\$ 230,373
Total	294,651	294,651	230,373	230,373
Liabilities:				
Short-Term Debt	69,615	69,615	81,422	81,422
Long-Term Debt	943,734	806,826	824,059	710,839
Total	\$ 1,013,349	\$ 876,441	\$ 905,481	\$ 792,261

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that fair value:

Cash Equivalents: The carrying amount approximates fair value because of the short-term maturity of these instruments. Fair value is determined based on quoted prices in active markets, a Level 1 fair value input.

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, 2024, 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, 2024.

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, 2024 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, 2024. 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, 2024, 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 is incorporated by reference to the information under "Election of Directors," "Corporate Governance - Director Nomination Process," "Committees of the Board of Directors - Audit Committee," and "Executive Compensation Policies - Insider Trading Policy" in the Company's definitive Proxy Statement for the 2025 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A of this report on Form 10-K.

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.ottetail.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 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," "Director Independence Determinations" and "Committees of the Board of Directors" in the Company's definitive Proxy Statement for the 2025 Annual Meeting.

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 2025 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 2025 Annual Meeting.

The following table sets forth information as of December 31, 2024 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	333,147 ⁽¹⁾	N/A	828,761 ⁽²⁾
1999 Employee Stock Purchase Plan	—	N/A	⁽³⁾
Equity compensation plans not approved by security holders	—	—	206,115
Total	333,147	—	1,034,876

(1) Includes 65,100, 78,600 and 73,500 performance-based share awards, assuming a maximum payout, granted in 2024, 2023 and 2022, respectively, and 115,947 restricted stock units outstanding as of December 31, 2024.

(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 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 2025 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>	
	2024	2023
Assets		
Current Assets		
Cash and Cash Equivalents	\$ 291,575	\$ 228,137
Accounts Receivable from Subsidiaries	5,642	2,555
Interest Receivable from Subsidiaries	117	117
Notes Receivable from Subsidiaries	4,706	—
Other	3,538	977
Total Current Assets	305,578	231,786
Investments in Subsidiaries	2,006,239	1,725,584
Notes Receivable from Subsidiaries	78,900	78,900
Deferred Income Taxes	69,781	65,244
Other Assets	109,057	50,795
Total Assets	\$ 2,569,555	\$ 2,152,309
Liabilities and Stockholders' Equity		
Current Liabilities		
Accounts Payable to Subsidiaries	\$ 7	\$ 7
Notes Payable to Subsidiaries	752,625	568,672
Other	19,100	15,320
Total Current Liabilities	771,732	583,999
Other Noncurrent Liabilities	49,424	45,455
Commitments and Contingencies		
Capitalization		
Long-Term Debt	79,900	79,849
Common Stockholders' Equity	1,668,499	1,443,006
Total Capitalization	1,748,399	1,522,855
Total Liabilities and Stockholders' Equity	\$ 2,569,555	\$ 2,152,309

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>		
	2024	2023	2022
Income			
Equity Income in Earnings of Subsidiaries	\$ 304,525	\$ 294,467	\$ 296,833
Interest Income from Subsidiaries	3,107	2,898	3,382
Other Income	15,085	10,496	466
Total Income	322,717	307,861	300,681
Expense			
Nonelectric Selling, General, and Administrative Expenses	23,016	12,816	17,269
Interest Expense	3,599	3,813	4,066
Interest Expense from Subsidiaries	5	6	5
Nonservice Cost Components of Postretirement Benefits	970	1,063	1,023
Total Expense	27,590	17,698	22,363
Income Before Income Taxes	295,127	290,163	278,318
Income Tax Benefit	6,535	4,028	5,866
Net Income	\$ 301,662	\$ 294,191	\$ 284,184

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>		
	2024	2023	2022
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	\$ 76,333	\$ 77,139	\$ 28,807
Cash Flows from Investing Activities			
Investment in Subsidiaries	(55,000)	(40,000)	(50,000)
Purchases of Investments and Other Assets	(53,085)	(1,754)	(3,175)
Other, net	1,394	1,686	1,480
Net Cash Used in Investing Activities	(106,691)	(40,068)	(51,695)
Cash Flows from Financing Activities			
Net (Repayments) Borrowings on Short-Term Debt	—	—	(22,637)
Borrowings from Subsidiaries	179,247	148,308	236,926
Payments for Shares Withheld for Employee Tax Obligations	(6,457)	(3,088)	(2,942)
Dividends Paid	(78,265)	(73,061)	(68,755)
Other, net	(729)	(339)	(461)
Net Cash Provided by Financing Activities	93,796	71,820	142,131
Net Change in Cash and Cash Equivalents	63,438	108,891	119,243
Cash and Cash Equivalents at Beginning of Period	228,137	119,246	3
Cash and Cash Equivalents at End of Period	\$ 291,575	\$ 228,137	\$ 119,246

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 the 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, 2024 and 2023 are as follows:

<i>(in thousands)</i>	<i>Accounts Receivable</i>	<i>Interest Receivable</i>	<i>Current Notes Receivable</i>	<i>Long-Term Notes Receivable</i>	<i>Accounts Payable</i>	<i>Current Notes Payable</i>
December 31, 2024						
Otter Tail Power Company	\$ 5,223	\$ —	\$ —	\$ —	\$ 7	\$ —
Northern Pipe Products, Inc.	36	7	—	5,000	—	66,170
Vinyltech Corporation	—	17	—	11,500	—	90,764
BTD Manufacturing, Inc.	—	78	—	52,000	—	5,662
T.O. Plastics, Inc.	42	15	4,706	10,400	—	—
Varistar Corporation	—	—	—	—	—	590,029
Otter Tail Assurance Limited	341	—	—	—	—	—
Total	\$ 5,642	\$ 117	\$ 4,706	\$ 78,900	\$ 7	\$ 752,625
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	—	—	—	—	—
Total	\$ 2,555	\$ 117	\$ —	\$ 78,900	\$ 7	\$ 568,672

Dividends

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

<i>(in thousands)</i>	2024	2023	2022
Cash Dividends Paid to Parent by Subsidiaries	\$ 78,191	\$ 72,982	\$ 68,680

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, 2024, 2023 and 2022:

<i>(in thousands)</i>	<i>Balance, January 1</i>	<i>Charged to Cost and Expenses</i>	<i>Deductions⁽¹⁾</i>	<i>Balance, December 31</i>
Allowance for Credit Losses				
2024	\$ 2,522	\$ 1,242	\$ (1,844)	\$ 1,920
2023	1,648	2,014	(1,140)	2,522
2022	1,836	909	(1,097)	1,648

⁽¹⁾ Amounts reflect deductions to the allowance for amounts written-off, net of recoveries.

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	Note Purchase Agreement dated as of March 28, 2024 between Otter Tail Power Company and the Purchases named therein
10.8	Sixth Amended and Restated Credit Agreement, dated as of December 11, 2024, by and between Otter Tail Corporation, as Borrower, and the banks named therein, with U.S. Bank National Association, as Administrative Agent
10.9	Fifth Amended and Restated Credit Agreement, dated as of December 11, 2024, by and between Otter Tail Power Company, as Borrower, and the banks named therein, with U.S. Bank Nation Association, as Administration Agent
10.10.0	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
10.10.1	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
10.10.2	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
10.10.3	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
10.10.4	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
10.10.5	Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003)
10.10.6	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
10.11	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.**
10.12.0	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
10.12.1	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
10.12.2	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
10.12.3	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
10.12.4	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
10.12.5	Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1
10.12.6	Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1
10.13.0	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**

No.	Description
10.13.1	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.
10.13.2	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.
10.14	Executive Survivor and Supplemental Retirement Plan (2020 Restatement)*
10.15	Nonqualified Retirement Plan (2021 Restatement)*
10.16	Otter Tail Corporation Executive Restoration Plus Plan, 2020 Restatement*
10.17	1999 Employee Stock Purchase Plan, As Amended (2016)
10.18	2014 Stock Incentive Plan*
10.19	2023 Stock Incentive Plan*
10.20	2025 Executive Annual Incentive Plan*
10.21	Form of Executive Performance Share Award Agreement (Executives)*
10.22	Form of Restricted Stock Unit Award Agreement (Executives)*
10.23	Form of Restricted Stock Award Agreement (Directors)*
10.24	Summary of Non-Employee Director Compensation (2024)*
10.25	Change in Control Severance Agreement, Chuck MacFarlane, dated February 24, 2012*
10.26	Change in Control Severance Agreement, Timothy Rogelstad, dated April 14, 2014*
10.27	Change in Control Severance Agreement, Paul Knutson, dated December 17, 2012*
10.28	Change in Control Severance Agreement, John Abbott, dated April 13, 2015*
10.29	Change in Control Severance Agreement, Todd Wahlund, dated January 1, 2024*
10.30	Change in Control Severance Agreement, Jennifer Smestad, dated January 1, 2018*
10.31	Form of Change in Control Severance Agreement (2023)*
10.32	Otter Tail Corporation Executive Severance Plan (2024)*
19	Insider Trading and Pre-Clearance Policy
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 19, 2025

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 /s/ Charles S. MacFarlane

Nathan I. Partain)
Chairman of the Board and Director)

Charles S. MacFarlane
Pro Se and Attorney-in-Fact
Dated: February 19, 2025

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. 2024 dividends were \$1.87 per share, and the year-end dividend yield was 2.5 percent. Total shareholder return grew at a compounded average annual rate of 12.5 percent over the past ten years.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Our Dividend Reinvestment and Share Purchase Plan provides shareowners of record with a convenient method for purchasing shares of Otter Tail Corporation common stock. Approximately 84 percent of eligible shareholders holding approximately 6 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.

2025 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 14, 2025 • 10:00 a.m., Central Daylight Time / Meeting Format: Virtual-only

2025 COMMON DIVIDEND DATES

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

KEY STATISTICS

Nasdaq	OTTR
Year-end stock price	\$73.84
Year-end market-to-book ratio	1.85
Annual dividend yield	2.5%
Shares outstanding (as of December 31, 2024)	41.8 million
Market capitalization (as of December 31, 2024)	\$3.1 billion
2024 average daily trading volume	233,304
Institutional holdings (shares as of December 31, 2024)	30.9 million

TRANSFER AGENT

EQ Shareowner Services
P.O. Box 64854, St. Paul, MN 55164-0854
Phone: 866-605-8638 or 651-450-4064

2024 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	Negative	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

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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: 2024/ Q4

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

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

GENERAL INFORMATION

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.

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:

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

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.)

<u>Schedules</u>	<u>Pages</u>
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-faqs-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>.

When to Submit

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

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).

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.

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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;

"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

'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.

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,

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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 filed..."

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: 2024/ 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) ☒ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2024
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) 04/15/2025
02 Title Vice President Finance		
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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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		230b		

26	Unrecovered Plant and Regulatory Study Costs 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	
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		397	

	Amounts included in ISO/RTO Settlement Statements		
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: ☐ Two copies will be submitted ☒ No annual report to stockholders is prepared		

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	Vice President, Finance	Andrew C. Miller		2024-01-01	
5	Vice President, Regulatory Affairs	Bruce G. Gerhardson			2024-07-31
6	Director, Public Policy & Government Affairs	Mark Bring			
7	General Counsel & Vice President, Legal Affairs *	Jennifer O. Smestad			
8	Vice President, Asset Management	JoAnn M. Thompson			
9	Vice President, Energy Supply	Bradley E. Tollerson			
10	Director, Human Resources & Safety	Peter E. Wasberg			
11	Vice President, Information Technology *	Don L. Redden			
12	Director, Communications	Stephanie A. Hoff			
13	Treasurer *	Todd Wahlund		2024-01-01	
14	Assistant Treasurer *	Tyler Nelson		2024-01-01	
15	* This individual is an employee of Otter Tail Corporation				
16	and a portion of their salary is allocated to the				
17	respondent. The reported amount is prorated to the				
18	utility.				

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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	Timothy Rogelstad, Director; President	Fergus Falls, Minnesota	false	false
3	John Abbott, Director	Fargo, North Dakota	false	false
4	Jennifer Smestad, Director	Fergus Falls, Minnesota	false	false

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
INFORMATION ON FORMULA RATES					
Does the respondent have formula rates?				☒ Yes ☐ No	
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
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
56	MISO FERC Electric Tariff	ER24-224
57	MISO FERC Electric Tariff	ER24-1636

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4		
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)?	☒ Yes ☐ No				
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
5	20230315-5126	03/15/2023	ER23-1379	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff
6	20240315-5088	03/15/2024	ER24-1503	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff

FERC FORM NO. 1 (NEW. 12-08)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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. - 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. - 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. - 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. - 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. - 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. - 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. - Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments. - State the estimated annual effect and nature of any important wage scale changes during the year. - 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. - 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. (Reserved.) - 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. - Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period. - 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. None.			
4. None.			
5. None.			
6. See Note 5 (Short-Term and Long-Term Borrowings) in the Notes to Financial Statements and the Capital Resource Section of Otter Tail Corporation's 2024 10-K filing with the Securities Exchange Commission (SEC).			
7. None.			
8. Local Unions 203, 239, 524 and 949 increased 4.0% effective 10/27/2024			
9. See Note 9, Commitments and Contingencies, in Part II and see Item 3, Legal Proceedings, in Part I of Otter Tail Corporation's 2024 10-K filing with the Securities Exchange Commission (SEC).			
10. None.			
12. None.			
13. None.			
14. Not Applicable.			

FERC FORM No. 1 (ED. 12-96)

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	3,223,553,452	3,024,574,378	
3	Construction Work in Progress (107)	200	235,991,197	146,671,993	
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,459,544,649	3,171,246,371	
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,070,942,949	1,009,079,480	
6	Net Utility Plant (Enter Total of line 4 less 5)		2,388,601,700	2,162,166,891	
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)		2,388,601,700	2,162,166,891	
15	Utility Plant Adjustments (116)				
16	Gas Stored Underground - Noncurrent (117)				
17	OTHER PROPERTY AND INVESTMENTS				
18	Nonutility Property (121)		195,981	217,138	
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)		27,066	30,227	
25	Sinking Funds (125)				
26	Depreciation Fund (126)				
27	Amortization Fund - Federal (127)				
28	Other Special Funds (128)		16,745,151	14,331,458	
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)		16,968,198	14,578,823
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		500	19,177
36	Special Deposits (132-134)		3,298,749	2,295,368
37	Working Fund (135)		11,162	12,513
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		20,762,357	22,294,293
41	Other Accounts Receivable (143)		13,227,026	8,384,943
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,497,018	1,495,442
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		6,853	6,853
45	Fuel Stock (151)	227	11,210,086	12,139,789
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	49,192,930	40,994,826
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	30,847	80,111
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)		4,746,543	4,730,948
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		21,862,585	21,271,185
62	Miscellaneous Current and Accrued Assets (174)		1,031,327	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)		123,883,947	112,007,320
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		3,882,468	3,226,368
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	873,917	1,223,484
72	Other Regulatory Assets (182.3)	232	120,753,262	120,900,369
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)		643,105	423,695
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	2,226,831	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)		191,021	215,669
82	Accumulated Deferred Income Taxes (190)	234	107,873,225	105,704,925
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		236,443,829	232,821,508
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,765,897,674	2,521,574,542

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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, 2023	146,671,993
January 31, 2024	148,592,881
February 29, 2024	143,343,689
March 31, 2024	146,991,483
April 30, 2024	154,251,621
May 31, 2024	176,024,608
June 30, 2024	202,874,895
July 31, 2024	220,239,499
August 31, 2024	237,612,935
September 30, 2024	235,173,408
October 31, 2024	239,723,824
November 30, 2024	213,850,121
December 31, 2024	235,991,197
13-month average for rate-making	192,410,935

(b) Concept: AccumulatedProvisionForUncollectibleAccountsCredit

As of December 31, 2024, total allowance for credit losses includes an amount of -\$53,035 for provisions for uncollectible accounts related to unbilled revenue estimates which is included in FERC account 173.

	December 31, 2024	December 31, 2023
Accum Prov. for Uncollectible Accts (FERC 144)	(1,497,018)	(1,495,442)
Estimated losses as a reduction of Unbilled Revenue included in FERC acct 173	(53,035)	(52,706)
Total Allowance for Credit Losses	(1,550,053)	(1,548,148)

(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, 2023	12,139,789
January 31, 2024	10,722,513
February 28, 2024	10,508,600
March 31, 2024	10,199,495
April 30, 2024	10,570,192
May 31, 2024	10,750,877
June 30, 2024	10,879,274
July 31, 2024	9,653,875
August 31, 2024	9,089,394
September 30, 2024	9,364,230
October 31, 2024	10,606,716
November 30, 2024	10,889,830
December 31, 2024	11,210,086
13-month average for rate-making	10,506,528

(d) Concept: AllowanceInventoryAndWithheld

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

Co-Gen REC Emission Allowance Inventory	30,847
	30,847

(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, 2023	4,730,948
January 31, 2024	7,296,385
February 29, 2024	7,238,877
March 31, 2024	6,499,818
April 30, 2024	8,395,273
May 31, 2024	8,748,716
June 30, 2024	7,458,629
July 31, 2024	6,449,284
August 31, 2024	6,850,776
September 30, 2024	5,797,506
October 31, 2024	4,941,616
November 30, 2024	5,265,668
December 31, 2024	4,746,543
13-month average for rate-making	<u>6,493,849</u>

FERC FORM No. 1 (REV. 12-03)

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	731,988,966	676,988,966	
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	327,976,802	299,566,317	
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)	(1,948,037)	(1,176,918)	
16	Total Proprietary Capital (lines 2 through 15)		1,058,018,231	975,378,865	
17	LONG-TERM DEBT				
18	Bonds (221)	256	867,000,000	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)		867,000,000	747,000,000	
25	OTHER NONCURRENT LIABILITIES				
26	Obligations Under Capital Leases - Noncurrent (227)				
27	Accumulated Provision for Property Insurance (228.1)				
28			673,467	620,797	

	Accumulated Provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)		45,393,705	46,185,000
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		42,163,371	36,476,624
35	Total Other Noncurrent Liabilities (lines 26 through 34)		88,230,543	83,282,421
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		69,615,052	81,421,764
38	Accounts Payable (232)		81,299,970	65,793,684
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		5,223,218	2,415,270
41	Customer Deposits (235)		428,580	498,154
42	Taxes Accrued (236)	262	16,050,414	18,314,311
43	Interest Accrued (237)		10,827,068	9,117,335
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		1,498,675	1,849,712
48	Miscellaneous Current and Accrued Liabilities (242)		13,324	477,551
49	Obligations Under Capital Leases-Current (243)			
50	Derivative Instrument Liabilities (244)		1,989,254	4,209,982
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)		186,945,555	184,097,763
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,211,418	1,156,731
57	Accumulated Deferred Investment Tax Credits (255)	266	14,990,084	15,171,590

58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	4,967,460	2,225,072
60	Other Regulatory Liabilities (254)	278	190,200,348	184,567,182
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort. (281)	272	9,681,887	10,501,748
63	Accum. Deferred Income Taxes-Other Property (282)		(a) 321,103,504	292,837,405
64	Accum. Deferred Income Taxes-Other (283)		(b) 22,548,644	25,355,765
65	Total Deferred Credits (lines 56 through 64)		565,703,345	531,815,493
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,765,897,674	2,521,574,542

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Amort of Loss on Reacquired Debt (pre holdco)	46,807
Deferred HLP Cost Recovery	(232,968)
South Dakota Flow Thru-Overheads	(72,056)
Prepaid Expenses	1,195,376
ADR Repair Allowance	1,197,838
Sec 162 & 174 R&D Deduction	1,725,185
Highway Reimbursements	1,135,193
AFUDC on Debt	4,695,368
Capitalized Overheads	(1,382,154)
Repairs Deduction - Basis Adjustments	3,507,738
Sec 481(a) Cap to Repair Basis Adjustments (PY)	(4,263,771)
Excess Tax over book Depreciation	338,116,913
North Dakota Investment Tax Credit - Federal Impacts	4,545,972
Excess Accumulated Deferred Tax due to Federal Rate Change	(32,764,973)
ASC 740 (SFAS 109) ADIT Credits - Property	3,653,036
	321,103,504

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Pensions	26,393,376
Conservation Improvement Program - MN & SD - Net (BTL)	3,435,701
Rate Rider Mechanism	-8,051,185
ND Rate Case Expenses	186,218
MN Rate Case Expenses	101,941
Regulatory Adjustments - JE 820 ESSRP	-683,233
Excess Accumulated Deferred Tax due to Federal Rate Change	-469,065
ASC 740 (SFAS 109) ADIT Credits - Non-Property	1,634,891
	22,548,644

FERC FORM No. 1 (REV. 12-03)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 (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

Do not report fourth quarter data in columns (e) and (f)

Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.

Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Use page 122 for important notes regarding the statement of income for any account thereof.

Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may be made to 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 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's revenues or recover amounts paid with respect to power or gas purchases.

Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income statement, and accounts.

If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.

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 of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.

Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.

If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote.

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)
1	UTILITY OPERATING INCOME									
2	Operating Revenues (400)	300	522,003,612	524,114,351			522,003,612	524,114,351		
3	Operating Expenses									
4	Operation Expenses (401)	320	266,921,019	279,671,571			266,921,019	279,671,571		
5	Maintenance Expenses (402)	320	34,233,072	36,423,449			34,233,072	36,423,449		
6	Depreciation Expense (403)	336	75,094,621	69,343,913			75,094,621	69,343,913		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	1,039,219	631,942			1,039,219	631,942		

8	Amort. & Depl. of Utility Plant (404-405)	336	6,341,272	3,904,889			6,341,272	3,904,889		
9	Amort. of Utility Plant Acq. Adj. (406)	336	(58,991)				(58,991)			
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)									
11	Amort. of Conversion Expenses (407.2)									
12	Regulatory Debits (407.3)		560,093	377,093			560,093	377,093		
13	(Less) Regulatory Credits (407.4)		2,816,927	1,903,988			2,816,927	1,903,988		
14	Taxes Other Than Income Taxes (408.1)	262	15,653,729	16,604,736			15,653,729	16,604,736		
15	Income Taxes - Federal (409.1)	262	(14,912,607)	(20,740,034)			(14,912,607)	(20,740,034)		
16	Income Taxes - Other (409.1)	262	(2,617,220)	(2,842,754)			(2,617,220)	(2,842,754)		
17	Provision for Deferred Income Taxes (410.1)	234,272	2,504,628	2,499,070			2,504,628	2,499,070		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234,272	(13,119,810)	(23,020,043)			(13,119,810)	(23,020,043)		
19	Investment Tax Credit Adj. - Net (411.4)	266	(753,028)	(744,518)			(753,028)	(744,518)		
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)		8				8			
23	Losses from Disposition of Allowances (411.9)									

24	Accretion Expense (411.10)		1,676,692	1,191,251			1,676,692	1,191,251		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		395,985,374	407,436,663			395,985,374	407,436,663		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		126,018,238	116,677,688			126,018,238	116,677,688		
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)		472,892	553,116						
34	(Less) Expenses of Nonutility Operations (417.1)		291,772	361,066						
35	Nonoperating Rental Income (418)		88,105	71,636						
36	Equity in Earnings of Subsidiary Companies (418.1)	119								
37	Interest and Dividend Income (419)		249,805	444,285						
38	Allowance for Other Funds Used During Construction (419.1)		2,794,202	1,199,621						
39	Miscellaneous Nonoperating Income (421)		2,264,062	2,962,042						
40			69,040	165,433						

	Gain on Disposition of Property (421.1)									
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,646,334	5,035,067						
42	Other Income Deductions									
43	Loss on Disposition of Property (421.2)									
44	Miscellaneous Amortization (425)									
45	Donations (426.1)		602,956	1,609,368						
46	Life Insurance (426.2)									
47	Penalties (426.3)			601,745						
48	Exp. for Certain Civic, Political & Related Activities (426.4)		405,673	295,150						
49	Other Deductions (426.5)		354,376	453,342						
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,363,005	2,959,605						
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	811,699	520,465						
54	Income Taxes- Other (409.2)	262	254,931	173,340						
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	776,436	708,407						
56	(Less) Provision for Deferred Income Taxes- Cr. (411.2)	234, 272	728,803	945,531						

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)		1,122,111	464,529						
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,161,218	1,610,933						
61	Interest Charges									
62	Interest on Long-Term Debt (427)		36,936,150	31,797,400						
63	Amort. of Debt Disc. and Expense (428)		382,763	366,910						
64	Amortization of Loss on Reacquired Debt (428.1)		24,648	24,648						
65	(Less) Amort. of Premium on Debt-Credit (429)									
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)									
67	Interest on Debt to Assoc. Companies (430)									
68	Other Interest Expense (431)		2,736,393	3,540,380						
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,863,988	1,864,858						
70	Net Interest Charges (Total of lines 62 thru 69)		38,215,966	33,864,480						
71			90,963,490	84,424,141						

	Income Before Extraordinary Items (Total of lines 27, 60 and 70)									
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)		90,963,490	84,424,141						

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

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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		298,174,396	272,406,309	
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)		90,963,490	84,424,141	
17	Appropriations of Retained Earnings (Acct. 436)				
17.1	Excess hydro licensing amortization		(234,904)	(270,380)	
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(234,904)	(270,380)	
23	Dividends Declared-Preferred Stock (Account 437)				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)				
30	Dividends Declared-Common Stock (Account 438)				
30.1			(62,553,005)	(58,385,674)	
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(62,553,005)	(58,385,674)	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings				
38			326,349,977	298,174,396	

	Balance - End of Period (Total 1,9,15,16,22,29,36,37)			
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)		1,626,825	1,391,921
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,626,825	1,391,921
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		327,976,802	299,566,317
	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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
STATEMENT OF CASH FLOWS				
1. 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. 2. 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. 3. 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. 4. 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)	90,963,490	84,424,141	
3	Noncash Charges (Credits) to Income:			
4	Depreciation and Depletion	72,888,260	68,697,443	
5	Amortization of (Specify) (footnote details)			
5.1	Amortization	7,072,454	4,663,356	
5.2	Vehicle depreciation allocated to various operating accounts	2,582,301	2,360,133	
8	Deferred Income Taxes (Net)	15,102,350	25,282,218	
9	Investment Tax Credit Adjustment (Net)	(181,506)	(744,518)	
10	Net (Increase) Decrease in Receivables	(3,899,971)	7,043,535	
11	Net (Increase) Decrease in Inventory	(4,344,002)	(8,087,402)	
12	Net (Increase) Decrease in Allowances Inventory			
13	Net Increase (Decrease) in Payables and Accrued Expenses	15,852,160	(10,012,269)	
14	Net (Increase) Decrease in Other Regulatory Assets	5,194,113	12,479,077	
15	Net Increase (Decrease) in Other Regulatory Liabilities	16,821,434	20,972,715	
16	(Less) Allowance for Other Funds Used During Construction	2,794,202	1,199,621	
17	(Less) Undistributed Earnings from Subsidiary Companies			
18	Other (provide details in footnote):			
18.1	Other: (increase) decrease in assets and deferred debits	(3,845,668)	(6,670,169)	
18.2	Other: increase (decrease) in liabilities and deferred cost	(10,009,821)	(18,575,815)	
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	201,401,392	180,632,824	
24	Cash Flows from Investment Activities:			

25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(304,269,261)	(241,946,769)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	21,157	51,898
30	(Less) Allowance for Other Funds Used During Construction	(2,794,202)	(1,199,621)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(301,453,902)	(240,695,250)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	557,486	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)	(342,140)	(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		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Other: (increase) decrease in funds on deposit with trustee	(1,003,381)	4,709,898
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(302,241,937)	(234,886,312)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	120,000,000	
62	Preferred Stock		
63	Common Stock	55,000,000	40,000,000
64	Other (provide details in footnote):		
64.1		(1,038,862)	

	Other: debt issuance expense		
66	Net Increase in Short-Term Debt (c)	(11,806,712)	73,218,121
67	Other (provide details in footnote):		
67.1	Other: change in checks written in excess of cash	1,219,096	(565,265)
67.2	Other: proceeds from capital infusions		
70	Cash Provided by Outside Sources (Total 61 thru 69)	163,373,522	112,652,856
72	Payments for Retirement of:		
73	Long-term Debt (b)		
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)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(62,553,005)	(58,385,674)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	100,820,517	54,267,182
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)	(20,028)	13,694
88	Cash and Cash Equivalents at Beginning of Period	31,690	17,996
90	Cash and Cash Equivalents at End of Period	11,662	31,690

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 Recquired Debt, and 257, Unamortized Gain on Recquired 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 approximately 134,000 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 earning 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 life of the receivables. We determine 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 are determined on an average cost basis.		
Property, Plant and Equipment		
Electric plant is stated at original cost less accumulated depreciation. The cost of additions includes purchased assets, 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 2024 and \$1.9 million in 2023. Significant additions or improvements that extend an asset's useful life are capitalized, while repairs and maintenance costs are expensed as incurred.		
Depreciation is recognized on a straight-line basis over the asset's estimated useful life. For certain asset classes, we employ a group or composite method of depreciation in which certain assets are combined and depreciated over the average life of the combined asset group. Actuarial studies are periodically performed to assess the remaining useful lives and salvage values of our assets, with any changes in these estimates incorporated into depreciation on a prospective basis. Gains or losses on group or composite asset dispositions are recorded to accumulated depreciation and impact current and future depreciation rates.		
Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Removal costs, when incurred, are charged against the regulatory liability.		
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	80
Distribution Plant	10	72
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 several 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 investments.		
Recoverability of Long-Lived Assets		
We review our long-lived assets including, among other assets, property, plant and equipment, capitalized cloud computing costs 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.		
Pension Plans and Other Benefits		
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.		
Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates. Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.		
We have elected to apply a minimum amortization method for determining the amount of amortization of net cumulative gains or losses to be included as a component of net periodic benefit cost for any annual period. Cumulative gains and losses recognized in accumulated other comprehensive income or as a deferred regulatory asset or liability that are in excess of 10% of the projected benefit obligation or the market value of pension plan assets are amortized over the expected remaining future service period of active plan participants. In periods in which the cumulative gains and losses do not exceed 10%, no amortization to net period benefit cost is recognized.		
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 adjustments 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, 2024 and 2023, our liability to participants under these deferred compensation plans was \$3.7 million and \$3.0 million. OTP contributions to these plans were \$0.3 million for		
each of the years ended December 31, 2024 and 2023. Losses recognized due to changes in our payment obligations in connection with these plans amounted to \$0.3 million for each of the years ended December 31, 2024 and 2023.		
Fair Value Measurements		

Fair value is defined as the price that would be received for an asset or 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 in this report's value:									
Name of Respondent: Otter Tail Power Company Date of Report: 2/31/2024 Year/Period of Report: End of 2024/ Q4									
Level 2 – Pricing inputs are other than quoted prices in active markets for identical assets or liabilities 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 this report, columns (b), (c), (d) and (e) are the amounts of accumulated other comprehensive income items, on a net of tax basis, where appropriate, is based on the lowest level input that is significant to the fair value measurement in its entirety.									
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.									
Value of each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a									
In this report, the Coyote Station owners include CMC, entered into a lignite service agreement (LSA) with Coyote Creek Mining Company, LLC (CCMC), 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 operation and providing a guarantee of the value of the Coyote Station owners are required to buy certain assets of CCMC at book value at termination prior to the end of the contract term and are providing a guarantee of the value of the Coyote Station owners because the Coyote Station owners are required to buy the assets, liabilities, results of operations and cash flow of CCMC at the end of the contract term at book value. Under current accounting standards, the purchase of a VIE is required to include the assets, liabilities, results of operations and cash flow of CCMC in its financial statements. No significant owner of Coyote Station owns a financial interest in Coyote Station and, individually, the power to direct the activities that most significantly impact CCMC. Therefore, the owners individually, including the owners of the VIE and its subsidiaries, are not required to consolidate CCMC in their financial statements.									
Line (a) For-Sale (net of tax) (b) Pension (c) Foreign Currency Adjustments (d) Other Flow Hedges (e) Interest Rate Swaps (f) Other Cash Flow Hedges (g) Other Cash Flow Hedges (h) Net Income Carried Forward from Page 1									
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 have not purchased all of the outstanding book value interests of CCMC the owners will satisfy or, if permitted by the LSA, 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, or 85% share of CCMC's unrecovered costs as of December 31, 2024, if recovery of such a loss is denied by regulatory authorities.									
Subsequent to the date of recognition or disclosure in the financial statements that occurred subsequent to December 31, 2024 through April 15, 2025, and did not identify any events requiring recognition or disclosure in these financial statements, except as disclosed in note 14.									
2. Receivables									
Receivables as of December 31, 2024 and 2023 are as follows:									
(in thousands)									
Preceding Quarter/Year to Date									
2024 2023									
Receivables									
Trade									
Other									
Unbilled receivables									
Total Receivables									
Less Allowance for Credit Losses									
Receivables, net of allowance for credit losses									
3. The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2024 and 2023:									
(in thousands)									
Beginning Balance, January 1									
Additions									
Reductions									
Ending Balance, December 31									
3. Regulatory Assets and Liabilities									
The following presents our regulatory assets and liabilities as of December 31, 2024 and 2023 and the period we expect to recover or refund such amounts:									
(in thousands)									
Balance of Regulatory Assets									
Account 219 at Beginning of Current Year									
Asset Retirement Obligations ¹									
Pension and Other Postretirement Benefit Plans ²									
Revenue Recovery Riders									
ISO Cost Recovery Trackers ³									
Deferred Production Expenses ⁴									
Fuel Clause Adjustments									
Derivative Instruments									
Other ⁵									
Total Regulatory Assets									
Regulatory Liabilities									
Deferred Production Expenses									
Pension and Other Postretirement Benefit Plans									
Fuel Clause Adjustments									
Revenue Recovery Riders									
ISO Cost Recovery Trackers									
North Dakota LDC Refunds									
Other									
Total Regulatory Liabilities									
Costs subject to depreciation without a rate of return.									
10. Revenue									
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.									
10. Revenue									
Investment in quality of 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 (the refund is the sum of the net increase in the federal income tax rate in 2017, multiplied by the amount of the deferred income taxes originated).

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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 in future periods.

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

North Dakota PTC Refunds represent PTCs earned from our wind energy facilities. These amounts are being allocated to customers over the life of the assets generating the credits.

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. The filing also 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. Interim rates went into effect on January 1, 2024. On July 3, 2024, we filed an update to our original request increasing the amount of the net annual revenue requirement from \$17.4 million to \$22.5 million, or a net increase of 10.9% in annual revenue, to account for certain items identified throughout the regulatory process.

On December 30, 2024, the NDPSC approved a settlement agreement between OTP and certain interested parties in the general rate case and issued its written order on final rates. The key provisions of the order include a revenue requirement of \$225.6 million, based on a return on rate base of 7.53%, and an allowed ROE of 10.10% on an equity ratio of 53.5%. The net annual revenue requirement includes a net increase of \$13.1 million, or 6.18%. Our revenue requirement was reduced by approximately \$3.0 million primarily due to the inclusion of forecasted PTCs plus adjustments for new customer load additions, which were not included in our updated request filed on July 3, 2024. Through the settlement of the case, the parties also agreed to establish an earnings sharing mechanism, whereby 70% of actual earnings in excess of a 10.20% ROE would be returned to customers, with OTP retaining the remaining 30%.

4. Electric Plant

Major classes of electric plant as of December 31, 2024 and 2023 include:

<i>(in thousands)</i>	December 31, 2024		December 31, 2023	
Electric Plant in Service				
Electric Plant in Service	\$	3,223,553	\$	3,024,574
Construction Work in Progress		235,991		146,672
Total Gross Electric Plant		3,459,545		3,171,246
Less Accumulated Depreciation and Amortization		1,070,943		1,009,079
Net Electric Plant	\$	2,388,602	\$	2,162,167

Depreciation expense for the years ended December 31, 2024 and 2023 totaled \$78.6 million and \$72.3 million.

The following table provides our ownership percentages and amounts included in the December 31, 2024 and 2023 balance sheets for our share of each of these jointly owned facilities:

<i>(dollars in thousands)</i>	Ownership Percentage	Electric Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Plant
December 31, 2024					
Big Stone Plant	53.9 %	\$ 345,990	\$ 459	\$ (135,065)	\$ 211,384
Coyote Station	35.0 %	188,066	813	(118,268)	70,611
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(8,445)	97,740
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(12,247)	65,937
Big Stone South–Brookings 345 kV line	50.0 %	53,167	—	(5,822)	47,345
Brookings–Southeast Twin Cities 345 kV line	4.8 %	28,013	1,131	(3,941)	25,203
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,693)	12,638
Jamestown– Ellendale 345 kV line	50.0 %	—	5,509	—	5,509
Big Stone South–Alexandria 345 kV line	40.0 %	—	2,418	—	2,418
Alexandria–Big Oaks 345 kV line	14.2 %	—	417	—	417
Oslo - Lake Ardoch 115 kV line	72.0 %	—	2,646	—	2,646
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

5. Short-Term and Long-Term Borrowings**Short-Term Debt**

The following is a summary of our line of credit as of December 31, 2024 and 2023:

<i>(in thousands)</i>	2024			2023	
	Line Limit	Amount Outstanding	Letters of Credit	Amount Available	Amount Available
OTP Credit Agreement	220,000	69,615	8,772	141,613	79,446

On December 11, 2024, OTP entered into a Fifth Amended and Restated Credit Agreement, amending and restating the previously existing credit agreement to extend the maturity date of the credit facility and adjust the maximum debt to total capitalization covenant. The credit agreement was also amended to increase the maximum borrowing capacity. The OTP agreement provides for a \$220.0 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 \$300.0 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 1.50%, depending on the benchmark interest rate selected, and is subject to adjustment based on our credit ratings. The weighted-average interest rate on our borrowings as of December 31, 2024 and 2023 was 5.61% and 6.70%.

The credit facility contains a number of restrictions on us, 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. The credit facility includes a cross-default provision whereby an event of default of other outstanding indebtedness will trigger an event of default under this agreement. The credit facility expires on December 11, 2029.

Long-Term Debt

The following is a summary of outstanding long-term debt as of December 31, 2024 and 2023:

Name of Respondent:		This report is:		Date of Report:		(in thousands)	
Otter Tail Power Company		(1) ☒ An Original		12/31/2024		December 31, 2024	
Series 2007C Senior Unsecured Notes		(2) ☐ A Resubmission		08/02/27		End of: 2024 Q4	
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%		07/25/30		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 2022A Senior Unsecured Notes		5.48%		04/01/34		60,000 60,000	
Series 2022B 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		4.07%		10/10/49		64,000 64,000	
Series 2020D Senior Unsecured Notes		3.69%		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	
Series 2024B Senior Unsecured Notes		5.77%		04/01/54		60,000 —	
Total						867,000 747,000	
On March 28, 2024, we entered into a Note Purchase Agreement pursuant to which we issued, in a private placement transaction, \$120.0 million of senior unsecured notes consisting of (a) \$60.0 million of 5.48% Senior Unsecured Notes due April 1, 2034, and (b) \$60.0 million of 5.77% Series 2024B Senior Unsecured Notes due April 1, 2054. Per the terms of the agreement, we may prepay all or any part of the notes in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount, as defined in the agreement; provided that no default or event of default exists under the agreement. Any prepayment of the Series 2024A Notes then outstanding on January 1, 2034, or the Series 2024B Notes then outstanding on or after October 1, 2053, will be made without any premium amount. Consistent with other of our borrowings, the agreement contains a number of restrictions on our business, including restrictions on our ability to merge, sell substantially all assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in certain transactions with affiliates. Our unsecured senior debt is subject to 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 certain transactions with related parties. The notes include a cross-default provision whereby an event of default of other outstanding indebtedness will trigger an event of default under the note. Maturities of long-term debt obligations as of December 31, 2024 for each of the next five years are as follows:							
Completed Construction		747,566,322		747,566,322		2025 2026 2027 2028 2029	
Debt Maturities		\$ —		\$ —		\$ 42,800 \$ — \$ 70,000	
Experimental Plant							
Financial Covenants							
Certain of our short- and long-term debt agreements require us to maintain certain financial covenants, including a maximum debt to total capitalization of either 0.60 to 1.00 or 0.65 to 1.00, depending on the debt agreement, a minimum interest and dividend coverage ratio of 1.50 to 1.00, and a maximum level of priority indebtedness. As of December 31, 2024, we were in compliance with these financial covenants.		3,222,767,301		3,222,767,301			
Employee Postretirement Benefits							
Leased to Others							
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 Plan (the ESSRP), both accounted for as defined benefit pension plans, and a postretirement healthcare plan accounted for as an other postretirement benefit plan.		595,672		595,672			
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 investments. None of the plan assets are invested in common stock or debt securities of OTP or Otter Tail Corporation.		235,991,197		235,991,197			
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 except for participants deemed to be "other participants."		190,479		190,479			
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 have worked for a minimum of 10 years of service. The plan is an unfunded plan and accordingly holds no plan assets.		3,459,544,649		3,459,544,649			
Pension Plan Assets. Otter Tail Corporation has established a Retirement Plans Administration Committee to develop and monitor our investment strategy for our 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), 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.		1,070,942,949		1,070,942,949			
Net Utility Plant (13 less (4))		2,368,601,700		2,368,601,700			
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 target 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 shows the target asset allocation permitted range along with the actual asset allocation as of December 31, 2024 and 2023:							
Asset Class				Permitted Range		Actual Allocation	
Return Enhancement				35 — 60 %		41 % 48 %	
Risk Management Alternatives				40 — 80 % 0 — 20 %		59 — 1	
Total		1,047,939,171		1,047,939,171		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 table provides inputs classified within the fair value hierarchy used to measure Pension Plan assets at December 31, 2024 and 2023 and assets measured using the net asset value method.									
Amortization and Depreciation of Producing Natural Gas Land and Lease Rights				Level 1	Level 2	Level 3	NAV		Total
December 31, 2024									
Equity Funds			\$	113,733	\$	—	\$	—	\$ 113,733
Fixed Income Funds				170,577		—	—	—	170,577
2023				9,833		—	—	—	9,833
U.S. Treasury Securities				23,264		—	—	—	23,264
SEI Energy Debt Collective Fund				—		—	1,032		1,032
December 31, 2023		21,473,184	21,473,184	317,407	—	—	1,032		318,439
Equity Funds				123,854		—	—	—	123,854
Fixed Income Funds				163,246		—	—	—	163,246
2023		1,069,412,355	1,069,412,355	10,694		—	—	—	10,694
U.S. Treasury Securities				22,615		—	—	—	22,615
SEI Energy Debt Collective Fund				—		—	1,478		1,478
December 31, 2023			\$	320,409	\$	—	\$	1,478	\$ 321,887
Investments in the SEI Energy Debt Collective Fund on December 31, 2024 and 2023 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. In its discretion, it 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 assets 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, 2024 and 2023 and the Total Leased to Others as of December 31, 2024 and 2023:									
Total Leased to Others (24 & 25)			Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits		
(in thousands)			2024	2023	2024	2023	2024	2023	
Held for Future Use									
Change in Fair Value of Plan Assets:									
Fair Value of Plan Assets at January 1		\$	321,887	\$	305,953	\$	—	\$	—
Depreciation			14,241		32,993		—		—
Company Contributions			—		1,219		1,253		2,971
Amortization			(17,689)		(1,219)		(1,253)		(8,636)
Participant Premium Payments							2,131		5,665
Total Held for Future Use (24 & 25)			318,439		321,887		—		—
Benefit Obligation:									
Benefit Obligation at January 1			310,513		300,354		11,802		48,694
Abandonment of Leases (Natural Gas)			3,785		3,606		—		551
(Benefit Payments)			16,742		16,025		635		2,353
			(17,690)		(17,059)		(1,218)		(8,636)
Acquisition of Plant		1,530,594	1,530,594		—		2,131		5,665
Acquisition of Plant					—		—		(17,038)
Liability Transfer			—		(369)		—		—
Actuarial (Gain) Loss			(7,818)		7,587		204		(2,234)
Total Accum Prov (equals Benefit Obligation at December 31)		1,070,942,949	1,070,942,949		310,513		11,802		29,361
Funded Status			\$ 12,907	\$	11,374	\$	(11,083)	\$	(29,193)
Amounts Recognized in Balance Sheet at December 31:									
FERC FORM No. 1 (ED. 12-89)			\$ 12,907	\$	11,374	\$	—	\$	—
Noncurrent Assets									
Current Liabilities					(1,227)		(1,212)		(2,405)
Noncurrent Liabilities and Deferred Credits			—		(9,856)		(10,590)		(26,956)
Net Asset (Liability)			\$ 12,907	\$	11,374	\$	(11,083)	\$	(29,193)
The accumulated benefit obligation of our Pension Plan was \$280.7 million and \$281.3 million as of December 31, 2024 and 2023. The accumulated benefit obligation of our ESSRP was \$11.1 million and \$11.8 million as of December 31, 2024 and 2023.									
The following assumptions were used to determine benefit obligations as of December 31, 2024 and 2023:									
		Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits			
		2024	2023	2024	2023	2024		2023	
Discount Rate		5.70 %	5.57 %	5.60 %	5.53 %	5.61 %		5.53 %	
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 %	4.50 %	n/a	n/a	n/a		n/a	
Participants Age 50 and Older ⁽³⁾		3.75 %	3.75 %	n/a	n/a	n/a		n/a	
Healthcare Cost Immediate Trend Rate		n/a	n/a	n/a	n/a	6.44 %		6.97 %	
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 2024 and 2023 reduced our obligation by \$4.6 million and \$2.1 million. Changes in plan participant census data decreased our benefit obligation by \$2.9 million in 2024. Actual returns on Pension Plan assets in 2024 were \$14.6 million, compared to an expected return of \$24.8 million, impacting our obligation by \$10.2 million. - For the ESSRP, an increase in the discount rate in 2024 and 2023 reduced our obligation by less than \$0.1 million and \$0.1 million. - For the postretirement healthcare plan, an increase in the discount rate in 2024 and 2023 reduced our obligation by \$0.2 million and \$1.3 million. Revised estimates of healthcare cost trends and participant contribution assumptions increased the benefit obligation by \$0.4 million in 2024. Changes in plan participant census data decreased our benefit obligation by \$0.9 million in 2024.									
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.		This report is:		Date of Report:		Year/Period of Report:			
Name of Respondent:		This report is:		Date of Report:		Year/Period of Report:			
Otter Tail Power Company		(2) Pension Benefits (Pension Plan)		12/31/2024		End of: 2024/ Q4			
(in thousands)		2024		2023		2024		2023	
Service Cost	\$ 3,785	FOOTNOTE DATA		—	\$ —	\$ 478	\$ 551		
Interest Cost	16,742	16,025		596	635	1,557	2,355		
Expected Return on Assets	(24,854)	(25,267)		—	—	—	—		
Amortization of Prior Service Cost	—	—		—	—	(6,142)	(6,593)		
Amortization of Net Actuarial Loss	153	—		—	—	—	—		
The following table includes the components of net periodic benefit cost for the years ended December 31, 2024 and 2023:									
Gross Electric Plant in Service									
December 31, 2023	2,409,543,663		596		\$ 635	\$ (4,107)	\$ (3,687)		
January 31, 2024	2,413,544,234								
February 29, 2024	2,417,446,974					\$ (7,685)	\$ (8,688)		
March 31, 2024	2,425,721,842					1,367	1,225		
April 30, 2024	2,435,913,684					\$ (6,318)	\$ (7,463)		
May 31, 2024	2,445,656,451								
June 30, 2024	2,450,676,880								
July 31, 2024	2,452,850,753								
August 31, 2024	2,459,489,224								
September 30, 2024	2,461,316,975		5.53 %		5.51 %	5.53 %	5.52 %		
October 31, 2024	2,464,998,689		7.00 %		n/a	n/a	n/a		
November 30, 2024	2,468,177,967		n/a		3.00 %	3.00 %	n/a		
December 31, 2024	2,475,500,979		4.50 %		n/a	n/a	n/a		
Participants to Age 39	3.50 %		4.00 %		n/a	n/a	n/a		
Participants Ages 40 to 49	2.75 %		3.38 %		n/a	n/a	n/a		
Participants Ages 50 and Older	2.444,649,940								
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.									
The following table includes the components of net periodic benefit cost for the years ended December 31, 2024 and 2023:									
Gross Plant Not Classified									
December 31, 2023	614,020,198		619,771,186						
January 31, 2024	646,932,429		646,574,943						
February 29, 2024	644,889,166		640,640,493						
March 31, 2024	646,373,482		(2,631)		(1,591)	—	—		
April 30, 2024	652,266,891		(2,631)		(1,591)	—	—		
May 31, 2024	653,574,023								
June 30, 2024	668,114,881								
July 31, 2024	672,580,445								
August 31, 2024	728,392,222								
September 30, 2024	747,566,222		2025		2027	2028	2029	2030-2034	
October 31, 2024	18,754		19,269		19,736	20,296	20,841	108,270	
November 30, 2024	1,259		660,690,360		1,108	1,048	1,119	4,535	
December 31, 2024	2,547		2,543		2,507	2,421	2,449	11,694	
January 31, 2024	22,560		23,028		23,351	23,765	24,409	124,499	
February 29, 2024									
March 31, 2024									
April 30, 2024									
May 31, 2024									
June 30, 2024									
July 31, 2024									
August 31, 2024									
September 30, 2024									
October 31, 2024									
November 30, 2024									
December 31, 2024									
In May 2024, the Environmental Protection Agency (EPA) published a final rule amending coal combustion residual (CCR) regulations. The final rule introduces new requirements for the management of coal									
13-month average for rate-making									
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the future. Revisions to our estimated compliance costs or further obligations could be identified through the process of performing the additional evaluations. Should such revisions be necessary or if additional cost obligations are identified, we will update our cash flows and resulting retirement obligation at that time.		This report is (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4		
Name of Respondent: Otter Tail Power Company		Income before income taxes for the years ended December 31, 2024 and 2023 consists entirely of domestic earnings.					
The provision for income taxes charged to income for the years ended December 31, 2024 and 2023 consisted of the following:							
(in thousands)							
Current		NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)					
Federal Income Taxes		\$ (13,769) \$ (20,376)					
State Income Taxes		(2,280) (2,669)					
Deferred		6,671 17,337					
Federal Income Taxes		6,671 17,337					
State Income Taxes		6,671 17,337					
Tax Credits		(586) (586)					
North Dakota Wind Tax Credit Amortization, Net of Federal Taxes		(586) (586)					
Investment Tax Credit Amortization		(11) (9)					
Total		1,648 \$ 1,648					
The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2024 and 2023 is as follows:							
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)
Income Taxes at Federal Statutory Rate				\$ 18,778	21.0 %	18,075	21.0 %
Increases (Decreases) in Tax from:							
State Taxes on Income, Net of Federal Tax				4,441	5.0	4,327	5.0
Production Tax Credits (PTC)				(20,106)	(22.5)	(17,394)	(20.2)
Amortization of Excess Deferred Income Taxes				(2,788)	(3.1)	(2,205)	(2.6)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax				(586)	(0.7)	(586)	(0.7)
Allowance for Equity Funds Used During Construction				(726)	(0.8)	(312)	(0.4)
Other, Net				(557)	(0.6)	(257)	(0.2)
Income Taxes Expense, Effective Tax Rate				\$ (1,544)	(1.7)%	\$ 1,648	1.9 %
OTCs, North Dakota wind energy 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, 2024 and 2023:							
4 (in thousands)						2024 2023	
Deferred Tax Assets							
Tax Credit Carryforwards						\$ 44,263	\$ 43,088
Other EMTs						18,305	20,204
Difference in book property						8,244	7,964
Cost of Removal						35,374	32,993
Net Operating Loss Carryforward						—	—
Other						(1,221)	(1,500)
Total Deferred Tax Assets						107,873	105,705
Deferred Tax Liabilities						(320,875)	(295,498)
Difference in book property						(26,393)	(25,264)
Pension Expense						(4,546)	(5,297)
Regulatory Liability						(5,288)	(2,262)
Impact of State Net Operating Losses on Federal Taxes						—	—
Other						3,768	(374)
Total Deferred Tax Liabilities						(353,334)	(328,695)
Deferred Income Taxes						\$ (245,461)	\$ (222,990)
The following report has as of December 31, 2024 and the respective periods of expiration:							
(in thousands)						Amount 2024-2037 2038-2045	
Federal Tax Credits					\$ 19,603	\$ —	\$ 19,603
State Tax Credits					21,648	—	21,648
Otter Tail (Loss) Accruals for Amortization of Nuclear Fuel Assemblies (120.5)		a consolidated U.S. federal income tax return and various state income tax returns.					
As of December 31, 2024, we had net operating loss carryforwards for state tax purposes totaling \$2.3 million that expire between 2029 and 2037, and state tax credits totaling \$18.3 million which expire between 2029 and 2037. 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, 2024, we have recognized tax benefits. As of December 31, 2024, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2021 for Minnesota state income taxes and prior to 2020 for Minnesota state income taxes.							
9. Commitments and Contingencies							
Estimated Net Salvage Value of Nuclear Fuel Materials in Line 9							
Electricity purchase agreements. We have commitments for the purchase of capacity and energy requirements under contractual agreements, including wind power purchase agreements extending into 2040. Generally, the terms of our wind power purchase agreements require us to purchase all of the electricity generated by a particular wind farm, but do not include fixed or minimum payments. The required payments are variable and the amounts due are determined based upon the amount of capacity available or electricity generated. Capacity and energy requirement costs for these agreements totaled \$6.0 million and \$5.6 million for the years ended December 31, 2024 and 2023.							
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 on 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, mining and transportation 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 coal requirements through December 31, 2026. There is no fixed minimum purchase requirement, and no amounts for this agreement have been included in the table below; however, 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 \$44.7 million and \$43.7 million for the years ended December 31, 2024 and 2023.							
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 fixed maturity date; however, per the terms of the agreements, our requirement to make payments 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 \$62.0 million.							
Land easement costs under these agreements totaled \$1.8 million and \$1.8 million for the years ended December 31, 2024 and 2023.							
19 Other Commitments. As of December 31, 2024, we had commitments under contracts for plant maintenance, software subscriptions and other services extending into 2046 which totaled approximately \$8.0 million							

20 future commitments as of December 31, 2024 were as follows:						
21 thousands	Other (Provide details in footnote)		Coal Purchase Commitments	Land Easement Payments	Other Commitments	
2025			\$ 24,192	\$ 1,897	\$ 560	
2026			24,416	1,902	474	
2027			25,127	1,941	481	
2028			25,839	1,981	489	
2029			27,102	2,021	272	
Beyond 2029			314,713	52,261	5,758	
Total			\$ 441,409	\$ 62,003	\$ 8,024	

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Solar Development. On October 30, 2024, we entered into an agreement to acquire the assets of a solar facility currently under development. The assets to be acquired include real property rights and interests, interconnection agreements, state and local permits, and other development assets. Per the agreement, the purchase price is equal to \$23.6 million, plus the reimbursement of certain interconnection costs and costs to purchase and store the main power transformer. Closing of the transaction is expected to occur in late 2025 or early 2026, and remains subject to certain conditions to close, including regulatory and other approvals. We would be subject to a termination fee of up to \$5.0 million if the seller has satisfied all required conditions to close but the transaction is not consummated.

Contingencies

FERC ROE. In November 2013 and February 2015, customers filed complaints with 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 issued an order on November 19, 2020, which 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 and remanded the matter to FERC to reopen the proceedings.

On October 17, 2024, FERC issued an Order on Remand modifying its ROE methodology and establishing a base ROE of 9.98% (10.48% with an adder) effective for the fifteen-month period from November 2013 to February 2015 and on a prospective basis beginning in September 2016, and required MISO transmission owners to provide refunds to customers for collections in excess of the base ROE of 9.98% for the applicable period, plus interest. In addition, FERC concluded the evidentiary record continues to support the ROE established for the period from February 2015 to May 2016.

Prior to FERC's Order on Remand, we had deferred recognition of certain revenues and recognized a refund liability which reflected the amount previously collected under the MISO tariff rate that we anticipated would be refunded to customers. Our previous estimated refund amount was larger than the actual amount ordered by FERC in the Order on Remand and was therefore reduced, which resulted in a pre-tax benefit of \$2.5 million recognized in our consolidated statements of income for the year ended December 31, 2024. The balance of the recorded refund liability as of December 31, 2024 was \$0.5 million.

Self-Funding of Transmission Upgrades for Generator Interconnections. FERC has granted transmission owners within MISO and other regional transmission organizations (RTOs) 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 have 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 proceedings, 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. In December 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.

In June 2024, FERC issued an Order to Show Cause proceeding against four RTOs, including MISO. Within its order, FERC indicates that the transmission tariffs of the RTOs appear to be unjust, unreasonable, and unduly discriminatory or preferential because they allow transmission owners to unilaterally elect transmission owner self-funding, which may increase costs, impose barriers to transmission interconnection and result in undue discrimination among interconnection customers.

The order required each RTO to submit filings to either 1) show cause as to why the transmission tariff remains just and reasonable and not duly discriminatory or preferential, or 2) to explain what changes to the tariff it believes would remedy the identified concerns. FERC has received a number of responses to its Order to Show Cause. In September 2024, in separate filings, MISO and transmission owners within MISO, including OTP, filed responses outlining the reasons why the self-funding option remains just and reasonable and not unduly discriminatory or preferential. Other responses have been provided by other RTOs, individual transmission owners, developers of renewable generation facilities and other interested parties.

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 the resolution of this matter 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 FERC may ultimately decide on the matter after RTOs' filings in response to the Order to Show Cause.

Other Contingencies. We are party to litigation and regulatory matters arising in the normal course of business. We regularly analyze relevant information and, as necessary, estimate and record accrued liabilities for legal, regulatory enforcement and other 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, 2024, other than those discussed above, will not be material.

10. Accumulated Other Comprehensive Income (Loss)

Our other comprehensive income (loss) 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 income (loss) for the years ended December 31, 2024 and 2023:

(in thousands)	2024	2023
Balance, Beginning of Period	\$ (1,177)	\$ (1,086)
Other Comprehensive Income (Loss) Before Reclassifications, net of tax	972	(115)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1,743)	24
Total Other Comprehensive Income (Loss)	(771)	(91)
Balance, End of Period	\$ (1,948)	\$ (1,177)

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, 2024, 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 47.2% and 57.7%, with total capitalization not to exceed \$2.2 billion based on our capital structure requirements as of December 31, 2024. As of December 31, 2024, our equity-to-total-capitalization ratio, including short-term debt, was 53.1% and our net assets restricted from distribution totaled approximately \$834.5 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 on a gross basis with assets and liabilities presented separately. 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, 2024 and 2023, we had outstanding pay-fixed, receive-variable swap agreements. The contracts outstanding as of December 31, 2024 had various settlement dates throughout 2025. The following presents the notional amounts and fair value of our derivative instruments as of December 31, 2024 and 2023:

(in thousands)		This report is:				2023	
Name of Respondent: Otter Tail Power Company Derivative Liabilities: Other Current Liabilities		(1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q 4	
Other Noncurrent Liabilities						187	
Total Derivative Liabilities						\$ 1,989 \$ 4,210	
ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)						— —	
						\$ 1,989 \$ 4,210	
During the years ended December 31, 2024 and 2023, contracts matured and were settled in an aggregate amount of a \$3.5 million loss and a \$16.5 million loss, respectively. Gains and losses recognized on the settlement of these contracts are included in the carrying amount of the contracts. When recognized in the statements of comprehensive income, the gains and losses are included in the carrying amount of the contracts. When recognized in the statements of comprehensive income, the gains and losses are included in the carrying amount of the contracts. When recognized in the statements of comprehensive income, the gains and losses are included in the carrying amount of the contracts.							
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.							
3. Fair Value of Financial Instruments							
4. 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.							
The following are parenthetical adjustments of plant accounts to indicate the negative effect of such accounts.							
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in Level 2 column (c). Also December 31, 2023 included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the							
Liabilities 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 entries 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 109, state the nature and use of plant included in this account and its substantial 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.							
(in thousands)		Carrying Amount		Fair Value		Carrying Amount	
Assets:		Balance		Retirements		Balance at	
Cash and Cash Equivalents		Beginning of Year		(d)		End of Year	
Line 1		(a)		(c)		(g)	
Liabilities:		(b)		(e)		(f)	
Short-Term Debt		69,615		69,615		81,422	
Long-Term Debt		863,834		729,952		744,210	
Total		933,449		799,567		825,632	
1. INTANGIBLE PLANT							
2. (301) Organization							
The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that fair value:							
Cash Equivalents: The carrying amount approximates fair value because of the short-term maturity of these instruments. Fair value is determined based on quoted prices in active markets, a Level 1 fair value input.							
3 Short-Term Debt: The carrying amount approximates fair value because the debt obligations are short-term in nature and the balances outstanding are subject to variable rates of interest which reset frequently, a Level 2 fair value input.							
4 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		36,413,736		15,871,512		52,285,248	
Included in the amounts presented in the accompanying balance sheets and statements of comprehensive income are of and for the years ended December 31, 2024 and 2023 are the following related party transactions between Otter Tail Corporation and Otter Tail Corporation:							
5 Enter Total of lines 2, 3, and 4)		38,412,181		15,871,512		54,283,663	
Accounts Receivable						7	
Accounts Payable						5,223	
6 Operating Revenues						18	
Operating and Maintenance Expenses						14,821	
7 A. Steam Production Plant							
Operating and maintenance expenses predominantly 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 primarily arise from rent charged to Otter Tail Corporation for office space usage.							
8 (310) Land and Land		1,654,157		1,654,157		1,654,157	
Otter Tail Corporation pays OTP for certain tax credits and other tax benefits, which are realized through the filing of Otter Tail Corporation's consolidated tax returns. We received \$5.4 million in February 2025, OTP received payments totaling \$21.6 million from Otter Tail Corporation in exchange for certain tax credits and other tax benefits.							
9 (311) Structures and		116,762,533		334,955		116,740,984	
The Otter Tail Power Company Foundation is an independent, not-for-profit, charitable entity. OTP and is not included in our financial statements. Contributions to the foundation during the years ended December 31, 2024 and 2023 were \$1.5 million and \$1.3 million, respectively. Cash contributions paid to the foundation during the years ended December 31, 2024 and 2023 were \$1.5 million and \$1.3 million, respectively.							
10 (312) Boiler Plant Equipment		320,037,692		2,035,568		320,682,634	
11 (313) Engines and Engine-Driven Generators							
12 (314) Turbogenerator Units		58,019,030		(27,950)		56,661,533	
13 (315) Accessory Electric Equipment		33,251,145		61,564		33,272,082	
14		6,042,252		603,042		6,481,054	

	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production	5,750,031	6,773,912	70,143			12,453,800
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	540,516,840	10,759,542	3,330,138			547,946,244
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	1,871,839	(1)				1,871,838
29	(332) Reservoirs, Dams, and Waterways	7,210,963					7,210,963
30	(333) Water Wheels, Turbines, and Generators	1,373,867	497,486	1,379			1,869,974
31	(334) Accessory Electric Equipment	1,778,754	(499,525)	12,436			1,266,793
32	(335) Misc. Power Plant Equipment	671,573	39,252				710,825
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)	13,206,619	37,212	13,815			13,230,016
36	D. Other Production Plant						
37	(340) Land and Land Rights	1,987,061	11,136				1,998,197

38	(341) Structures and Improvements	52,797,924	(9,990)				52,787,934
39	(342) Fuel Holders, Products, and Accessories	7,762,795	1,238	33,012			7,731,021
40	(343) Prime Movers	140,588,439	1,411,318	435,000			141,564,757
41	(344) Generators	547,769,579	45,518,874	458,115	(82,800)		592,747,538
42	(345) Accessory Electric Equipment	111,524,443	2,262,402				113,786,845
43	(346) Misc. Power Plant Equipment	3,172,619	493,461	77,623	82,800		3,671,257
44	(347) Asset Retirement Costs for Other Production	20,144,041					20,144,041
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	885,746,901	49,688,439	1,003,750			934,431,590
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,439,470,360	60,485,193	4,347,703			^(b) 1,495,607,850
47	3. Transmission Plant						
48	(350) Land and Land Rights	23,946,988	1,588,951		(586,635)		24,949,304
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements						
50	(353) Station Equipment	189,552,423	25,078,607	457,485			214,173,545
51	(354) Towers and Fixtures	197,050,600	4,266				197,054,866
52	(355) Poles and Fixtures	174,132,189	10,023,754	2,679,453			181,476,490
53	(356) Overhead Conductors and Devices	193,157,663	11,213,502	2,352,916			202,018,249
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices	77,461					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)	777,917,324	47,909,080	5,489,854	(586,635)		^(b) 819,749,915
59	4. Distribution Plant						
60	(360) Land and Land Rights	1,551,119					1,551,119
61	(361) Structures and Improvements						
62	(362) Station Equipment	100,507,892	3,795,938	175,397			104,128,433

63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	90,210,135	4,214,808	342,221			94,082,722
65	(365) Overhead Conductors and Devices	63,365,052	2,931,802	489,409			65,807,445
66	(366) Underground Conduit						
67	(367) Underground Conductors and Devices	134,078,349	18,723,585	1,059,654	(39,139)		151,703,141
68	(368) Line Transformers	135,607,045	8,248,511	1,431,414	39,139		142,463,281
69	(369) Services	66,297,204	2,408,061	128,798			68,576,467
70	(370) Meters	38,189,597	35,121,450	1,227,349			72,083,698
71	(371) Installations on Customer Premises	10,212,038	246,435	112,683			10,345,790
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	14,586,956	550,706	497,695			14,639,967
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	654,605,387	76,241,296	5,464,620			725,382,063
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	1,674,790	809,563				2,484,353
87	(390) Structures and Improvements	40,105,542	6,717,203				46,822,745

88	(391) Office Furniture and Equipment	9,375,506	1,566,592	3,569,819			7,372,279
89	(392) Transportation Equipment	43,865,555	7,919,612	3,425,996			48,359,171
90	(393) Stores Equipment						
91	(394) Tools, Shop and Garage Equipment	5,853,837	602,438				6,456,275
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment	1,749,200	98,301	10,699			1,836,802
94	(397) Communication Equipment	11,342,179	3,069,976				14,412,155
95	(398) Miscellaneous Equipment						
96	SUBTOTAL (Enter Total of lines 86 thru 95)	113,966,609	20,783,685	7,006,514			127,743,780
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)	113,966,609	20,783,685	7,006,514			127,743,780
100	TOTAL (Accounts 101 and 106)	3,024,371,861	221,290,766	22,308,691	(586,635)		3,222,767,301
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)	3,024,371,861	221,290,766	22,308,691	(586,635)		3,222,767,301

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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, 2023	38,412,181
January 31, 2024	38,477,510
February 29, 2024	43,760,816
March 31, 2024	44,973,706
April 30, 2024	48,720,953
May 31, 2024	49,114,687
June 30, 2024	49,643,091
July 31, 2024	53,090,883
August 31, 2024	53,348,643
September 30, 2024	53,712,561
October 31, 2024	53,784,145
November 30, 2024	53,891,406
December 31, 2024	54,283,693
13-month average for rate-making	48,862,637

[\(b\)](#) 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, 2023	1,439,470,360
January 31, 2024	1,442,281,311
February 29, 2024	1,442,490,906
March 31, 2024	1,442,724,929
April 30, 2024	1,440,617,521
May 31, 2024	1,442,030,114
June 30, 2024	1,441,739,001
July 31, 2024	1,442,033,015
August 31, 2024	1,441,044,070
September 30, 2024	1,441,415,103
October 31, 2024	1,444,870,952
November 30, 2024	1,490,219,520
December 31, 2024	1,495,607,850
13-month average for rate-making	1,449,734,204

[\(c\)](#) 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, 2023	777,917,324
January 31, 2024	784,819,880
February 29, 2024	786,929,923
March 31, 2024	788,236,850
April 30, 2024	789,545,448
May 31, 2024	790,427,074
June 30, 2024	796,737,795
July 31, 2024	797,415,975
August 31, 2024	798,349,122
September 30, 2024	806,610,893
October 31, 2024	808,977,104
November 30, 2024	811,550,726
December 31, 2024	819,749,915
13-month average for rate-making	796,712,925

[\(d\)](#) 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, 2023	654,605,387
January 31, 2024	656,259,110
February 29, 2024	678,243,610
March 31, 2024	682,279,374
April 30, 2024	687,227,332
May 31, 2024	689,678,033
June 30, 2024	692,374,966
July 31, 2024	696,647,044
August 31, 2024	703,256,824
September 30, 2024	707,800,958
October 31, 2024	713,733,810
November 30, 2024	718,482,675
December 31, 2024	725,382,063
13-month average for rate-making	692,767,014

[\(e\)](#) 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, 2023	113,966,609
January 31, 2024	111,452,429
February 29, 2024	112,954,152
March 31, 2024	114,081,927
April 30, 2024	114,782,597
May 31, 2024	115,047,035
June 30, 2024	116,555,608
July 31, 2024	115,930,726
August 31, 2024	117,059,388
September 30, 2024	119,886,341
October 31, 2024	122,130,122
November 30, 2024	122,419,861
December 31, 2024	127,743,780
13-month average for rate-making	117,231,583

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
ELECTRIC PLANT LEASED TO OTHERS (Account 104)						
Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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47	TOTAL					

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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			595,672
21	Other Property:			
22	Various			
47	TOTAL			595,672

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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, 2023	9,038	3,000	12,038
January 31, 2024	9,038	3,000	12,038
February 29, 2024	—	—	—
March 31, 2024	—	—	—
April 30, 2024	—	—	—
May 31, 2024	—	—	—
June 30, 2024	—	—	—
July 31, 2024	—	—	—
August 31, 2024	—	—	—
September 30, 2024	—	—	—
October 31, 2024	—	—	—
November 30, 2024	595,672	—	595,672
December 31, 2024	595,672	—	595,672
13-month average for rate-making			93,494

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	Astoria LTSA 2020-2026	4,854,240	
2	MN Elec Vehicle DCFC Infrastructure	1,972,754	
3	Dist Sub Transformer Purchases (22)	1,228,710	
4	Central Stores Yard Expansion	1,190,778	
5	Oslo - Ardoch 115 Line	2,645,668	
6	Granville Relocate 41.6kV Line	1,547,649	
7	Oslo 115kV 5-Breaker Ring Bus Cash	4,920,699	
8	EMS Upgrades - Evergreen (2023)	2,404,909	
9	JETx Project Develop	5,459,885	
10	BSS - Alexandria 345kV	2,417,881	
11	VQ Milbank - Marietta Switching Sta	2,475,779	
12	VQ Milbak 115/12.5 Substation	4,232,163	
13	VQ Big Stone 230 Sub Addition	2,099,290	
14	Ashtabula Repower	31,444,920	
15	Luverne Repower	43,829,516	
16	Ashtabula III Repower	39,837,066	
17	VQ Milbank 115/12.5kV Dist Sub In	3,780,125	
18	Solway Solar Land Purchase	2,075,645	
19	Milbank Area Service Building Repla	1,272,529	
20	Abercrombie Solar	2,979,517	
21	Finley/McVille- Rebuild 41.6	1,138,717	
22	Battle Lk-Otter East ESR	1,324,147	
23	Milbank:RailWay Ave.-New	1,695,127	
24	Battle-Otter Outlet East Feed	2,228,437	
25	Rush Otter South Feeder Upgrad	2,805,290	
26	Pelican Rapids-City Lighting	1,456,815	
27	Fergus-Bury Hoot Lake Feeders	1,217,611	
28	Alex-Co Rd 4 Move	1,106,620	

29	Total Projects under \$1,000,000	60,348,710
43	Total	235,991,197

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	992,301,265	992,301,265		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	75,094,621	75,094,621		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,039,219	1,039,219		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,582,301	2,582,301		
7	Other Clearing Accounts	(46,309)	(46,309)		
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)	78,669,832	78,669,832		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(22,241,548)	(22,241,548)		
13	Cost of Removal	(4,021,049)	(4,021,049)		
14	Salvage (Credit)	2,275,744	2,275,744		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(23,986,853)	(23,986,853)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(1,719,091)	(1,719,091)		
17.2	Additional Debit or Cr. Items (Describe, details in footnote):	2,744,161	2,744,161		
18	Book Cost or Asset Retirement Costs Retired	(70,143)	(70,143)		

19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,047,939,171	1,047,939,171		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	274,256,765	274,256,765		
21	Nuclear Production				
22	Hydraulic Production-Conventional	6,699,318	6,699,318		
23	Hydraulic Production-Pumped Storage				
24	Other Production	261,459,627	261,459,627		
25	Transmission	182,416,081	182,416,081		
26	Distribution	275,444,723	275,444,723		
27	Regional Transmission and Market Operation				
28	General	47,662,657	47,662,657		
29	TOTAL (Enter Total of lines 20 thru 28)	1,047,939,171	1,047,939,171		

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
December 31, 2023	503,216,671	176,421,666	264,237,617	48,425,310	992,301,265
January 31, 2024	509,336,956	177,312,886	264,996,397	46,151,172	997,797,411
February 29, 2024	513,143,416	178,053,329	265,949,469	46,472,918	1,003,619,133
March 31, 2024	516,778,060	178,459,086	266,085,317	46,860,998	1,008,183,461
April 30, 2024	519,093,308	178,280,994	266,744,120	47,064,374	1,011,182,795
May 31, 2024	522,521,103	178,831,575	267,727,169	47,208,712	1,016,288,559
June 30, 2024	525,688,539	178,885,803	268,289,885	47,527,845	1,020,392,072
July 31, 2024	528,601,505	179,624,322	269,025,111	47,276,135	1,024,527,074
August 31, 2024	531,116,159	180,351,084	270,164,795	47,609,186	1,029,241,224
September 30, 2024	534,712,928	180,053,793	271,226,232	47,912,864	1,033,905,817
October 31, 2024	538,164,542	180,797,770	272,390,753	48,086,818	1,039,439,883
November 30, 2024	540,179,296	181,770,552	273,597,723	48,592,839	1,044,140,409
December 31, 2024	542,415,710	182,416,081	275,444,723	47,662,657	1,047,939,171
13-month average for rate-making	524,997,553	179,327,611	268,913,793	47,450,141	1,020,689,098

*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
December 31, 2023	503,216,671	176,421,666	264,237,617	48,425,310	992,301,265
January 31, 2024	509,336,956	177,312,886	264,996,397	46,151,172	997,797,411
February 29, 2024	513,143,416	178,053,329	265,949,469	46,472,918	1,003,619,133
March 31, 2024	516,778,060	178,459,086	266,085,317	46,860,998	1,008,183,461
April 30, 2024	519,093,308	178,280,994	266,744,120	47,064,374	1,011,182,795
May 31, 2024	522,521,103	178,831,575	267,727,169	47,208,712	1,016,288,559
June 30, 2024	525,688,539	178,885,803	268,289,885	47,527,845	1,020,392,072
July 31, 2024	528,601,505	179,624,322	269,025,111	47,276,135	1,024,527,074
August 31, 2024	531,116,159	180,351,084	270,164,795	47,609,186	1,029,241,224
September 30, 2024	534,712,928	180,053,793	271,226,232	47,912,864	1,033,905,817
October 31, 2024	538,164,542	180,797,770	272,390,753	48,086,818	1,039,439,883
November 30, 2024	540,179,296	181,770,552	273,597,723	48,592,839	1,044,140,409
December 31, 2024	542,415,710	182,416,081	275,444,723	47,662,657	1,047,939,171
13-month average for rate-making	524,997,553	179,327,611	268,913,793	47,450,141	1,020,689,098

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

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4					
INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)								
1. Report below investments in Account 123.1, Investments in Subsidiary Companies. 2. 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. 3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1. 4. 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. 5. 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. 6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year. 7. 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). 8. 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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28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								
42	Total Cost of Account 123.1 \$		Total					

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
MATERIALS AND SUPPLIES					
1. 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. 2. 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)	12,139,789	~~11~~ 11,210,086	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)	9,483,207	~~10~~ 10,404,594	Production	
8	Transmission Plant (Estimated)	14,243,402	~~17~~ 17,759,384	Various	
9	Distribution Plant (Estimated)	16,940,778	~~20~~ 20,663,958	Various	
10	Regional Transmission and Market Operation Plant (Estimated)				
11	Assigned to - Other (provide details in footnote)	327,439	~~364~~ 364,994	Fleet Service	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	40,994,826	49,192,930		
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	53,134,615	60,403,016		

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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, 2023	12,139,789
January 31, 2024	10,722,513
February 28, 2024	10,508,600
March 31, 2024	10,199,495
April 30, 2024	10,570,192
May 31, 2024	10,750,877
June 30, 2024	10,879,274
July 31, 2024	9,653,875
August 31, 2024	9,089,394
September 30, 2024	9,364,230
October 31, 2024	10,606,716
November 30, 2024	10,889,830
December 31, 2024	11,210,086
13-month average for rate-making	10,506,528

(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, 2023	9,483,207
January 31, 2024	9,710,441
February 28, 2024	10,021,938
March 31, 2024	10,047,360
April 30, 2024	10,176,035
May 31, 2024	10,271,043
June 30, 2024	10,239,543
July 31, 2024	10,280,219
August 31, 2024	10,405,144
September 30, 2024	10,505,919
October 31, 2024	10,429,076
November 30, 2024	10,399,587
December 31, 2024	10,404,594
13-month average for rate-making	10,182,623

(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, 2023	14,243,402
January 31, 2024	14,622,522
February 28, 2024	14,171,648
March 31, 2024	13,996,322
April 30, 2024	14,276,788
May 31, 2024	15,016,204
June 30, 2024	16,552,681
July 31, 2024	17,893,567
August 31, 2024	17,706,339
September 30, 2024	17,927,405
October 31, 2024	18,086,380
November 30, 2024	18,228,516
December 31, 2024	17,759,384
13-month average for rate-making	16,190,858

(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, 2023	16,940,778
January 31, 2024	16,801,716
February 28, 2024	17,327,945
March 31, 2024	15,738,515
April 30, 2024	18,230,685
May 31, 2024	18,784,762
June 30, 2024	18,717,832
July 31, 2024	18,210,395
August 31, 2024	19,013,553
September 30, 2024	18,980,737
October 31, 2024	18,553,865
November 30, 2024	19,789,499
December 31, 2024	20,663,958
13-month average for rate-making	18,288,788

[\(e\)](#) 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, 2023	327,439
January 31, 2024	314,372
February 28, 2024	311,209
March 31, 2024	323,158
April 30, 2024	338,472
May 31, 2024	332,610
June 30, 2024	352,822
July 31, 2024	364,280
August 31, 2024	369,096
September 30, 2024	368,577
October 31, 2024	364,699
November 30, 2024	374,088
December 31, 2024	364,994
13-month average for rate-making	346,601

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 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 three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j).
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 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/transferees of allowances acquired and identify associated companies (See "associated companies" 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)	
1	Balance-Beginning of Year	116,208	80,111	15,310		14,054		14,054		365,404		525,030.00	80,
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									14,054		14,054	
5	Returned by EPA	179										179	
6													
7													
8	Purchases/Transfers:												
9	Renewable Energy Credits		(49,264)										(4,
10													
11													
12													
13													
14													
15	Total		(49,264)										(4,
16													
17	Relinquished During Year:												
18	Charges to Account 509	4,788										4,788	
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	111,599	30,847	15,310		14,054		14,054		379,458		534,475
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
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
45	Gains	203	5							203	4	406
46	Losses											

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: AllowanceInventoryNumber

Includes 1,256 of initial allocations from EPA and 4,749 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>2023</u>	<u>2024</u>
Solar REC Emission Allowance Inventory	41,789	0
Co-gen REC Emission Allowance Inventory	<u>38,322</u>	<u>30,847</u>
	80,111	30,847

(d) Concept: AllowancesIssuedLessWithheldAllowancesNumber

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

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q4							
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/transferees 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	5,699		876								6,575	
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	96										96	

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	5,719		876							6,595		
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												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: AllowanceInventoryNumber

Includes 876 of initial allocations from EPA and 4,823 rollover allowances for Cross State Air Pollution Rule.

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

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q4	
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						

FERC FORM No. 1 (ED. 12-88)

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q4	
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	(a) Hoot Lake Plant Depreciation - MN	1,077,685		407.4	307,910	769,775	
22	(a) Hoot Lake Hydro Depreciation - MN	145,799		407.4	41,657	104,142	
49	TOTAL	1,223,484			349,567	873,917	

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Page 230b

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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

FERC FORM No. 1 (ED. 12-88)

Page 230b

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	J1485 - Hankinson to Wahpeton Facility Study	41,983	561.7	42,364	561.7
23	J1221 and J1485 Astoria to Brookings 345 kV Line Facility Study	46,093	561.7	45,712	561.7
24	J1221 and J1485 Astoria Substation Breakers Facility Study	18,359	561.7	17,977	561.7
25	J1575 Warsaw to Donaldson Facility Study	9,388	561.7	9,388	561.7
26	J2086 - Buffalo 345kV Interconnection Facility Study	15,450	561.7	15,237	561.7
27	J1989 - Twin Brooks-Ellendale 345kV Interconnection Facility Study	27,272	561.7	26,733	561.7
28	J1961 - Buffalo 115kV Interconnection Facility Study	12,585	561.7	11,745	561.7
29	DISIS-Wahpeton and Buffalo Cap Banks Facility Study	24,980	561.7	23,218	561.7
39	Total	196,110		192,374	
40	Grand Total	196,110		192,374	

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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)

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q4	
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		2,684,443	407.4	2,684,443		
3	Big Stone Plant	960,150	138,609	407.4	8,989	1,089,770	
4	Coyote Station	4,155,729	723,297			4,879,026	
5	Astoria Station	297,285	72,598			369,883	
6	Wind Generation - Langdon	1,203,426	236,777			1,440,203	
7	Wind Generation - Ashtabula	1,218,815	275,982			1,494,797	
8	Wind Generation - Ashtabula III	244,739	317,434			562,173	
9	Wind Generation - Luverne	1,269,446	273,751			1,543,197	
10	Wind Generation - Merricourt	1,245,685	570,999			1,816,684	
11	Hoot Lake Solar	21,633	115,453			137,086	
12	Post-retirement Benefit Plans:						
13	ESSRP	1,060,649		See Note	768,290	292,359	
14	Pension	85,227,116	2,795,020	228.3	153,704	87,868,432	
15	Post Retirement Medical Benefits		4,603,326	228.3	4,603,326		
16	Alternative Revenue Program Riders:						
17	MN Renewable Resource Rider Accrued Revenues	403,637		See Note	403,637		
18	MN Decoupling	2,598,483	1,462,737	442	4,672	4,056,548	
19	Conservation Improvement Program Costs & Incentives - MN		37,238,963	186	37,238,963		
20	Energy Efficiency Program - SD	203,311	377,940	186	264,320	316,931	
21	SD Transmission Cost Recovery Rider Accrued Revenues	184,994	23,411	See Note	208,405		

22	ND Renewable Resource Rider Accrued Revenues	485,783		(e) See Note	485,783	
23	SD Phase in Rider		637,425	(f) See Note	558,920	78,505
24	ISO Cost Recovery Trackers:					
25	MISO Schedule 26 and 26A Trans Cost Recovery Rider True-up	346,961	266,380	(g) See Note	49,905	563,436
26	SPP Cost Recovery Rider	120,481		(h) See Note	120,481	
27	Deferred Rate Case Expenses:					
28	MN Deferred Rate Case Expenses Subject to Recovery	754,187		407.3	377,094	377,093
29	ND Deferred Rate Case Expenses Subject to Recovery	453,988	497,536	407.3	235,529	715,995
30	Other:					
31	MN Fuel Clause Adjustment	6,711,766	684	(i) See Note	6,712,450	
32	ND Fuel Clause Adjustment	581,744	4,693,922	(j) See Note	3,198,264	2,077,402
33	SD Fuel Clause Adjustment		689,835	(k) See Note	549,702	140,133
34	Derivatives Marked-to-Market Losses	4,209,982	2,554,776	244	4,775,504	1,989,254
35	Property/Non Property Related Items	6,940,379	3,060,451	190, 254 & 282	1,056,475	8,944,355
36	See Footnote in Notes to Financial					
37	Statements for amortization periods.					
44	TOTAL	120,900,369	64,311,749		64,458,856	120,753,262

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Regulatory Asset Description	Docket
Asset Retirement Obligations	RM02-7-000
MN Renewable Resource Rider Accrued Revenues	E017/M-23-496
MN Decoupling	E017/M-24-55
Conservation Improvement Program Costs & Incentives - MN	E017/M-24-49
Energy Efficiency Program - SD	EL24-07
SD Transmission Cost Recovery Rider Accrued Revenues	EL23-033
ND Renewable Resource Rider Accrued Revenues	PU-23-343
SD Phase in Rider	EL24-020
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
ND Deferred Rate Case Expenses Subject to Recovery	PU-23-342
MN Fuel Clause Adjustment	E017/AA-24-65
ND Fuel Clause Adjustment	PU-23-342
SD Fuel Clause Adjustment	EL18-021

(b) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 219, 228.3 and 283 were debited.

(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(d) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(e) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(f) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(g) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(h) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(i) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(j) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

(k) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts 440, 442, 444, and 445 were debited.

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

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q4	
MISCELLANEOUS DEFERRED 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		11,253,151	182.3	11,253,151		
3	Energy Efficiency Program - SD		3,275,755	182.3	3,275,755		
4	Deposits for Construction Related Activities	1,126,998	1,983,635	186.0	883,802	2,226,831	
47	Miscellaneous Work in Progress						
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)						
49	TOTAL	1,126,998				2,226,831	

FERC FORM No. 1 (ED. 12-94)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	206,348	220,022
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	105,498,577	107,653,203
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	105,704,925	107,873,225
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)	105,704,925	107,873,225
Notes			
Not Applicable			

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredIncomeTaxes

	BALANCE AT BEGIN OF YEAR	BALANCE AT END OF YEAR
Post Retirement Benefits	13,711,889	12,255,224
Executive Supplemental Pension	2,322,252	2,087,305
Reserve for Bad Debts	394,363	394,785
Performance Shares	246,872	275,367
Accrued Vacation Pay	1,251,608	1,180,133
Capitalized Int. on Construction	7,037,116	7,465,639
Post Employment Benefits	210,476	43,480
Bonus Incentive	1,401,458	1,081,418
Nonqualified Retirement Savings	472,441	526,475
Capitalized A & G	512,927	422,283
Customer Rebates Capitalized	393,323	386,313
Asbestos Removal Costs Capitalized	32,992,884	35,374,470
Stock Incentives	111,062	255,352
Executive Restoration Plan	269,883	380,132
Unicap Adjustment	17,227	32,178
Medicare Part D	107,384	84,094
Flow-Through Items	(104,177)	(146,809)
Federal ITC - Solar	0	571,522
Wind Energy Income Tax Credits-ND	28,390,374	24,659,961
ASC 740 Unamortized ITC	356,501	342,646
ASC 740 Recognition of Regulatory Assets (Liab.)	2,599,461	2,564,947
Excess Accumulated Deferred Tax due to Federal Rate Change	(1,894,230)	(1,615,460)
Wind Production Tax Credit Deferral (Asset)	14,697,483	19,031,748
	105,498,577	107,653,203

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 an general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlir 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 bee issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulativ
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 t Respons In Sinki and Otl Fund Amou (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								

FERC FORM NO. 1 (ED. 12-91)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 2024-12-31	Year/Period of Report End of: 2024/ Q4
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. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation. 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. 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. 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	676,988,966	
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	55,000,000	
16	Ending Balance Amount	731,988,966	
17	Other Paid in Capital		
18	Beginning Balance Amount		
19.1	Increases (Decreases) in Other Paid-In Capital		
20	Ending Balance Amount		
40	Total	731,988,966	

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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		

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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, and 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 note 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 debt, give details of (a) interest advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers.
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 date of 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) 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 (j)
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
3	Senior Unsecured Notes 3.07%, Series A	181	10,000,000		52,446			10/10/2019	10/10/2029	10/10/2019
4	Senior Unsecured Notes 4.68%, Series A	181	60,000,000		233,049			02/27/2014	02/27/2029	02/27/2014
5	Senior Unsecured Notes 3.22%, Series A	181	10,000,000		49,855			02/25/2020	02/25/2030	02/25/2020
6	Senior Unsecured Notes 3.22%, Series B	181	40,000,000		192,872			08/20/2020	08/20/2030	08/20/2020
7	Senior Unsecured Notes 2.74%, Series A	181	40,000,000		188,991			11/29/2021	11/29/2031	11/29/2021
8	Senior Unsecured Notes 5.48%, Series A	181	60,000,000		299,902			03/28/2024	04/01/2034	03/28/2024
9		181	50,000,000		643,807			08/20/2007	08/20/2037	08/20/2007

	Senior Unsecured Notes 6.47%, Series D									
10	Senior Unsecured Notes 3.52%, Series B	181	26,000,000		136,360			10/10/2019	10/10/2039	10/10/20
11	Senior Unsecured Notes 3.62%, Series C	181	10,000,000		47,778			02/25/2020	02/25/2040	02/25/20
12	Senior Unsecured Notes 5.47%, Series B	181	90,000,000		347,548			02/27/2014	02/27/2044	02/27/20
13	Senior Unsecured Notes 4.07%, Series A	181	100,000,000		511,350			02/07/2018	02/07/2048	02/07/20
14	Senior Unsecured Notes 3.82%, Series C	181	64,000,000		335,655			10/10/2019	10/10/2049	10/10/20
15	Senior Unsecured Notes 3.92%, Series D	181	15,000,000		71,667			02/10/2020	02/10/2050	02/10/20
16	Senior Unsecured Notes 3.69%, Series B	181	100,000,000		464,405			11/29/2021	11/29/2051	11/29/20
17	 Senior Unsecured Notes 3.77%, Series C	181	90,000,000		434,532			05/20/2022	05/31/2052	05/20/20
18	Senior Unsecured Notes 5.77%, Series B	181	60,000,000		299,902			03/28/2024	04/01/2054	03/28/20
19	Subtotal		867,000,000		4,832,265					
20	Reacquired Bonds (Account 222)									
21										
22										
23										
24	Subtotal									
25	Advances from Associated Companies (Account 223)									
26										
27										

28										
29	Subtotal									
30	Other Long Term Debt (Account 224)									
31										
32										
33										
34	Subtotal									
33	TOTAL		867,000,000							

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription
July 15, 2020 - Docket No. E017/S-20-454
FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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)	90,963,490	
2	Reconciling Items for the Year		
3			
4	Taxable Income Not Reported on Books		
5	Interest Capitalized on Construction	2,641,343	
6	Net Gain from Property Retirements	(515,189)	
7	Miscellaneous Taxable Items		
8	Conservation Improvement Programs	(734,227)	
9	Deductions Recorded on Books Not Deducted for Return		
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj.)	(1,544,154)	
11	Provision for Reserves	(5,900,020)	
12	Miscellaneous Unallowed Deductions	51,003,354	
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	88,775,148	
21	Removal Costs	(9,016,572)	
22	Charges to Reserves	5,102,481	
23	Leveraged ESOP Deduction	1,155,500	
24	Sec 481(a) Cap to Repair Basis Adjustments		
25	Miscellaneous Other Deductions	43,078,003	
27	Federal Tax Net Income	6,820,036	
28	Show Computation of Tax:		

29	Federal Tax (LINE 27 X 21%)	1,432,208
30	Tax (Credits) and Adjustments	(1,074,156)
31	Prior Period Adjustments	(14,458,959)
32	Transfer Net Operating Loss to Deferred Carryforward	
33	Total Federal Income Tax	(14,100,907)
34	Charged to Account 5410.1001	(14,912,607)
35	Charged to Account 5410.2001	811,700
36	Charged to Account 5410.4120	
37	(a) Total	(14,100,907)

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: ComputationOfTaxDescription

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 2024. The other members of the affiliated group and their respective federal income tax provisions are as follows:

Otter Tail Corporation	-3,093,304
BTD Manufacturing, Inc.	2,975,103
Northern Pipe Products, Inc.	22,594,707
Vinyltech Corporation	32,344,625
T. O. Plastics, Inc.	-892,134
Otter Tail Assurance Limited	-146,844
Total	53,782,153

The consolidated federal income tax liability has been allocated to members of the consolidated tax group based on a standalone method and according to a tax sharing agreement among the members. The sum of the amounts allocated to the companies included in the tax return filing equals the consolidated amount.

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 that 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.
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 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 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.
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a footnote. Designate debit and credit adjustments.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending.
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 charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also show the amounts charged to Accounts 408.1 and 409.1.
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)
1		Income Tax			910,673		1,432,208	1,984,829		358,052
2		Unemployment Tax			693		37,804	37,491		1,006
3		Federal Insurance Tax					6,012,336	6,006,971		5,365
4	Subtotal Federal Tax				911,366		7,482,348	8,029,291		364,423
5		Property Tax	Minnesota		9,481,907		8,346,239	8,985,645		8,842,501
6		Income Tax	Minnesota		838,644		293,940	838,643		293,941
7		Unemployment Tax	Minnesota		46,752		79,692	79,129		47,315
8		Property Tax	North Dakota		4,053,343		4,486,254	4,951,932		3,587,665
9		Income Tax	North Dakota		2		117,271	117,272		1
10		Unemployment Tax	North Dakota		930		39,431	39,367		994
11		Other Taxes and Fees	North Dakota		25,523		105,308	104,996		25,835
12		Property Tax	South Dakota		2,955,861		2,723,776	2,791,228		2,888,409
13		Unemployment Tax	South Dakota		119		3,464	3,622		(39)

14		Income Tax	Other							
15		Unemployment Tax	Other		(371)		948	1,443		(866)
16		Other Taxes and Fees	Other		235		795	795		235
17	Subtotal State Tax				17,402,945		16,197,118	17,914,072		15,685,991
40	TOTAL				18,314,311		23,679,466	25,943,363		16,050,414

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: TaxesIncurredOther
Account 409.2: 811,699 Other 15,533,115
(b) Concept: TaxesIncurredOther
Account 184: 37,804
(c) Concept: TaxesIncurredOther
Account 184: 6,012,336
(d) Concept: TaxesIncurredOther
Account 409.2: 187,211 Other (58,262)
(e) Concept: TaxesIncurredOther
Account 184: 79,692
(f) Concept: TaxesIncurredOther
Account 408.2: 7,848
(g) Concept: TaxesIncurredOther
Account 409.2: 67,720 Other 2,831,763
(h) Concept: TaxesIncurredOther
Account 184: 39,431
(i) Concept: TaxesIncurredOther
Account 184: 3,464
(j) Concept: TaxesIncurredOther
Account 184: 948
(k) Concept: TaxesIncurredOther
Account 151: 795

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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%	15,086,533	190.0		411.4	741,835		14,344,698	25 years	
3	4%								—	
4	7%								—	
5	10%		411.4		411.4				—	
6	30%	85,057	190.0	183,206	411.4	9,799		258,464	25 years	
7	40%		190.0	388,318	411.4	1,396		386,922	25 years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	15,171,590		571,524		753,030		14,990,084		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10									—	
47	OTHER TOTAL									
48	GRAND TOTAL	15,171,590		571,524		753,030		14,990,084		

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4			
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	1,820,040	456	7,073,723	7,779,039	2,525,356
2	Asset Reclass	190,716	184	22,184,838	24,213,459	2,219,337
3	ASC 842 Leases	157,306	173		8,851	166,157
4	Deferred Revenue	57,010	456	89,936	89,536	56,610
47	TOTAL	2,225,072		29,348,497	32,090,885	4,967,460

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 relating 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	10,501,748	(812,727)						254	(7,134)	9,681,88
5	Other										
5.1	Other (provide details in footnote):								0		
5.2							0		0		
8	TOTAL Electric (Enter Total of lines 3 thru 7)	10,501,748	(812,727)							(7,134)	9,681,88
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)	10,501,748	(812,727)							(7,134)	9,681,88
18	Classification of TOTAL										
19	Federal Income Tax	7,736,425	(608,059)				0		0	(7,134)	7,121,23
20	State Income Tax	2,765,323	(204,668)				0		0		2,560,65
21	Local Income Tax						0		0		

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating 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				Bal Enc
			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	292,837,405	24,653,677	663,702		6,401	254		182.3	4,282,525	321
3	Gas						0		0		
4	Other (Specify)						0		0		
5	Total (Total of lines 2 thru 4)	292,837,405	24,653,677	663,702		6,401				4,282,525	321
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	292,837,405	24,653,677	663,702		6,401				4,282,525	321
10	Classification of TOTAL										
11	Federal Income Tax	221,125,263	18,763,179	761,512		4,850				3,592,610	242
12	State Income Tax	71,712,142	5,890,498	(97,810)		1,551				689,915	78
13	Local Income Tax										

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Amort of Loss on Reacquired Debt (pre holdco)	46,807
Deferred HLP Cost Recovery	(232,968)
South Dakota Flow Thru-Overheads	(72,056)
Prepaid Expenses	1,195,376
ADR Repair Allowance	1,197,838
Sec 162 & 174 R&D Deduction	1,725,185
Highway Reimbursements	1,135,193
AFUDC on Debt	4,695,368
Capitalized Overheads	(1,382,154)
Repairs Deduction - Basis Adjustments	3,507,738
Sec 481(a) Cap to Repair Basis Adjustments (PY)	(4,263,771)
Excess Tax over book Depreciation	338,116,913
North Dakota Investment Tax Credit - Federal Impacts	4,545,972
Excess Accumulated Deferred Tax due to Federal Rate Change	(32,764,973)
ASC 740 (SFAS 109) ADIT Credits - Property	3,653,036
	321,103,504

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 Year
			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	22,110,553	(8,939,079)	(6,006,539)	131	149			b1 See Note	(65,214)	19,1
4	a1 Nonutility & Other	3,245,212			743,358	552,707					3,4
9	TOTAL Electric (Total of lines 3 thru 8)	25,355,765	(8,939,079)	(6,006,539)	743,489	552,856				(65,214)	22,5
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)	25,355,765	(8,939,079)	(6,006,539)	743,489	552,856				(65,214)	22,5
20	Classification of TOTAL										

21	Federal Income Tax	16,493,080	(6,772,356)	(4,540,488)	563,356	418,857				18,509	14,4
22	State Income Tax	8,862,685	(2,166,723)	(1,466,051)	180,133	133,999				(83,723)	8,1
23	Local Income Tax										

NOTES

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	26,393,376
Conservation Improvement Program - MN & SD - Net (BTL)	3,435,701
Rate Rider Mechanism	-8,051,185
ND Rate Case Expenses	186,218
MN Rate Case Expenses	101,941
Regulatory Adjustments - JE 820 ESSRP	-683,233
Excess Accumulated Deferred Tax due to Federal Rate Change	-469,065
ASC 740 (SFAS 109) ADIT Credits - Non-Property	1,634,891
	<u>22,548,644</u>

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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	(a) Deferred Income Taxes:					
2	ASC 740	356,501	190	13,855		342,646
3	ADIT Legacy Reclass	135,665,839	(a) See Note	5,851,191	229,622	130,044,270
4	Post-retirement Benefit Plans:					
5	Post Retirement Medical Benefits	17,085,974	182.3 & 228.3	6,142,104	638,089	11,581,959
6	Fuel Clause Adjustment:					
7	MN Refundable Fuel Clause Adjustment Revenues	11,283,176	(a) See Note	14,396,724	14,545,625	11,432,077
8	ND Refundable Fuel Clause Adjustment Revenues		(a) See Note	6,741,171	6,741,171	
9	SD Refundable Fuel Clause Adjustment Revenues	66,671	(a) See Note	1,395,645	1,328,974	
10	Alternative Revenue Program Riders:					
11	ND Transmission Cost Recovery Rider Accrued Refund	994,402	(a) See Note	227,148	1,153,692	1,920,946
12	MN Renewable Resource Rider Accrued Revenues		(a) See Note	603,465	5,428,711	4,825,246
13	SD Transmission Cost Recovery Rider Accrued Refund		(a) See Note	204,639	418,273	213,634
14	ND Renewable Resource Rider Accrued Revenues		(a) See Note	881,686	2,767,000	1,885,314
15	SD Phase-in Rider	176,623	(a) See Note	485,522	308,899	
16	ND Generation Cost Recovery Rider	185,303	449.1 & 431	365,767	180,464	
17	MN Transmission Cost Recovery Rider Accrued Refund	1,249,706	(a) See Note	829,594	620,367	1,040,479
18	MN EITE Cost Recovery Rider	45,178	(a) See Note	34,132	369,828	380,874
19	SD Phase-in for AMI	329,201	(a) See Note	240,608	43,392	131,985

20	MN Decoupling	776,883	442 & 445	70,520	1,215,555	1,921,918
21	MN Uplift Program Rider	625,888	in See Note	71,032	132,109	686,965
22	MN EUIC Rider for AMI	420,844	in See Note	421,609	20,507	19,742
23	ND AMDT Rider	2,132,708	in See Note	1,174,276	73,184	1,031,616
24	Conservation Improvement Program Costs & Incentives - MN	618,898	182.3	7,732,403	8,377,226	1,263,721
25	North Dakota PTC Refunds	12,010,702			8,088,434	20,099,136
26	ISO Cost Recovery Trackers:					
27	MISO Schedule 26 and 26A Trans Cost Recover Rider True- up	359,314	in See Note	1,163,606	1,545,083	740,791
28	SPP MN Cost Tracker				383,352	383,352
29	Other:					
30	MN portion of gain on sale of Wahpeton	55,763	407.4	5,576		50,187
31	MN Credit Card Fees Tracker	127,608			75,882	203,490
32	See Footnote in Notes to Financial					
33	Statements for amortization periods.					
41	TOTAL	184,567,182		49,052,273	54,685,439	190,200,348

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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-21-311 E017/AA-22-214 E017/AA-23-181
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
MN Renewable Resource Rider Accrued Revenues	E017/M-22-577
ND Renewable Resource Rider Accrued Revenues	PU-23-343
SD Phase-in Rider	EL23-015
ND Generation Cost Recovery Rider	PU-23-342
MN Transmission Cost Recovery Rider Accrued Refund	E017/M-23-152
MN EITE Cost Recovery Rider	E017-M-23-162
SD Phase-in for AMI	EL23-015
MN Decoupling	E017/M-23-144
MN Uplift Program Rider	E017-M-22-133
MN EUIC Rider for AMI	E017/M-23-131
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, 190, 236, 282, 283.

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(e) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(f) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(g) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(h) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(i) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(j) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(k) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(l) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(m) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 444, 445.

(n) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Offsetting accounts were 440, 442, 445.
(o) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
Offsetting accounts were 440, 442, 444, 445.
(p) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
Offsetting accounts were 440, 442, 444, 445.
(q) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
Offsetting accounts were 440, 442, 444, 445.
FERC FORM NO. 1 (REV 02-04)

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4		
Electric Operating Revenues							
1. 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. 2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total. 3. 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. 4. 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. 5. Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2. 6. 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.) 7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases. 8. For Lines 2,4,5, and 6, see Page 304 for amounts relating to unbilled revenue by accounts. 9. 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	132,922,727	135,000,005	1,174,545	1,254,809	105,692	105,555
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	99,002,292	92,482,286	1,046,727	982,756	27,110	27,141
5	Large (or Ind.) (See Instr. 4)	210,985,061	217,745,016	3,403,734	3,477,561	830	843
6	(444) Public Street and Highway Lighting	4,118,045	3,921,745	13,776	14,427	658	655
7	(445) Other Sales to Public Authorities	3,691,090	3,766,451	42,486	42,662	1,229	1,241
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	450,719,215	452,915,503	5,681,268	5,772,215	135,519	135,435
11	(447) Sales for Resale	11,077,150	12,459,056	301,219	371,113		
12	TOTAL Sales of Electricity	461,796,365	465,374,559	5,982,487	6,143,328	135,519	135,435
13	(Less) (449.1) Provision for Rate Refunds	(365,767)					
14	TOTAL Revenues Before Prov. for Refunds	462,162,132	465,374,559	5,982,487	6,143,328	135,519	135,435

15	Other Operating Revenues						
16	(450) Forfeited Discounts	774,408	871,329				
17	(451) Miscellaneous Service Revenues	a 332,647	352,447				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	815,117	1,189,518				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	b 5,057,792	4,461,012				
22	(456.1) Revenues from Transmission of Electricity of Others	52,861,516	51,865,486				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	59,841,480	58,739,792				
27	TOTAL Electric Operating Revenues	522,003,612	524,114,351				
Line12, column (b) includes \$ 2,612,481 of unbilled revenues.							
Line12, column (d) includes 25,703 MWH relating to unbilled revenues							

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: MiscellaneousServiceRevenues

<u>Description of Revenue</u>	<u>Q4 2024</u>	<u>Q4 2023</u>
All others (under \$250,000 each)	332,647	352,447
Total	332,647	352,447

(b) Concept: OtherElectricRevenue

<u>Description of Revenue</u>	<u>Q4 2024</u>	<u>Q4 2023</u>
Sale of steam	1,564,908	1,129,715
Load Control & Dispatch	1,538,951	1,567,355
Renewable Energy RECs Generated	686,000	821,797
All others (under \$250,000 each)	1,267,933	942,145
Total	5,057,792	4,461,012

FERC FORM NO. 1 (REV. 12-05)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4		
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				

FERC FORM NO. 1 (NEW. 12-05)

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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	869,392	109,504,952	105,677	8,227	0.1260
3	9.02 Residential Service- Controlled Demand	114,879	12,553,051	4,308	26,666	0.1093
4	11.03 Outdoor Lighting - Energy Only	96	9,192	19		0.0958
5	11.04 Outdoor Lighting	1,373	243,260	1,255	1,094	0.1772
6	11.07 LED Street and Area Lighting	647	365,233	1,836		0.5645
7	12.01 Small Power Producer Rider		1,160	40		
8	14.01 Water Heating - Controlled Service (Off-Peak)	30,146	3,174,890	11,486		0.1053
9	14.04 Controlled Service - Interruptible Load	215	15,000	8	26,924	0.0698
10	14.05 Controlled Service - Interruptible Load	139,929	9,646,202	9,155		0.0689
11	14.06 Controlled Service - Deferred Load	10,409	979,312	823	12,647	0.0941
12	14.07 Fixed Time of Delivery Service	5,098	341,110	352		0.0669
13	14.08 Air Conditioning Control Rider		(72,123)	563		
14	14.09 Voluntary Renewable Energy Rider		17,847	172		
15	14.10 WAPA Bill Crediting Program Rider		(42,659)	113		
16	14.12 Off-Peak Electric Vehicle Rider	121	10,418	15	8,034	0.0861
17	Other	(858)	(42,363)	(30,130)	28	0.0494

41	TOTAL Billed Residential Sales	1,171,447	136,704,482	105,692	11,084	0.1167
42	TOTAL Unbilled Rev. (See Instr. 6)	3,098	(3,781,755)			(1.2207)
43	TOTAL	1,174,545	132,922,727	105,692	11,113	0.1132

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: AverageNumberOfCustomersPerMonthResidentialSalesBilled
Average number of customers are included within the Residential Service categories listed.
FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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	922	107,332	49	2,190	0.1164
4	9.03 Farm Service	76,760	8,414,677	2,723	3,090	0.1096
5	10.01 General Service	206,428	27,321,337	19,774		0.1324
6	10.02 General Service	578,337	62,865,672	4,614	13,625	0.1087
7	10.03 Commercial Time-of-Use	17,798	1,663,460	16		0.0935
8	10.04 Commercial Time-of-Use	70	9,399			0.1343
9	10.07 EV DCFC General Service - Time of Day	330	45,203	2	22,602	0.1370
10	11.02 Irrigation Service	5,279	499,021	127		0.0945
11	11.03 Outdoor Lighting - Energy Only	1,764	185,834	244		0.1053
12	11.04 Outdoor Lighting	3,881	655,617	1,377	476	0.1689
13	11.05 Municipal Pumping Service					
14	11.06 Fire Sirens			8		
15	11.07 LED Street and Area Lighting	2,911	1,307,542	2,034	643	0.4492
16	12.01 Small Power Producer Rider		760	33		
17	12.02 Small Power Producer Rider		324			
18	14.01 Water Heating - Controlled Service (Off-Peak)	1,549	125,726	358		0.0812
19	14.04 Controlled Service - Interruptible Load	45,978	2,455,268	272	9,027	0.0534

20	14.05 Controlled Service - Interruptible Load	49,418	2,943,010	2,055	1,432	0.0596
21	14.06 Controlled Service - Deferred Load	16,648	1,172,189	479	2,447	0.0704
22	14.07 Fixed Time of Delivery Service	20,153	1,142,197	436		0.0567
23	14.08 Air Conditioning Control Rider		(13,558)	25	(542)	
24	14.09 Voluntary Renewable Energy Rider		3,622	20		
25	14.1 WAPA Bill Crediting Program Rider		(140,905)	26	(5,419)	
26	14.12 Off-Peak Electric Vehicle Rider	28	2,364	1		0.0844
27	Other	(58)	217,668	(7,563)	(29)	(3.7529)
41	TOTAL Billed Small or Commercial	1,028,196	110,983,759	27,110	37,927	0.1079
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	18,531	(11,981,467)			(0.6466)
43	TOTAL Small or Commercial	1,046,727	99,002,292	27,110	38,610	0.0946

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4			
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	10.03 Commercial Time-of-Use	555,404	44,786,861	13	3,445,143	0.0806
4	10.04 Large General Service	516,723	44,903,033	829	54,165	0.0869
5	10.05 Large General Service - Time of Day	1,156,787	79,590,362	31	2,567,431	0.0688
6	10.06 Super Large General Service	728,770	29,535,889	1	29,535,889	0.0405
7	11.01 Standby Service - Option A Firm	147	18,010	1	18,010	0.1225
8	11.03 Outdoor Lighting - Energy Only	160	14,510	16	907	0.0907
9	11.04 Outdoor Lighting	574	101,786	58	1,755	0.1773
10	11.07 LED Street and Area Lighting	598	246,775	138	1,788	0.4127
11	12.01 Small Power Producer Rider		134	3	45	
12	12.02 Small Power Producer Rider					
13	12.03 Small Power Producer Rider		15	1	15	
14	14.01 Water Heating - Controlled Service (Off-Peak)	18	1,394	3	465	0.0774
15	14.02 Real Time Pricing Rider	74,534	3,030,153	2	1,515,077	0.0407
16	14.03 Large General Service Rider	316,691	13,383,307	9	1,487,034	0.0423
17	14.04 Controlled Service - Interruptible Load	42,757	2,096,658	57	36,783	0.0490
18		1,901	86,594	22	3,936	0.0456

	14.05 Controlled Service - Interruptible Load					
19	14.06 Controlled Service - Deferred Load	2,914	160,945	10	16,094	0.0552
20	14.07 Fixed Time of Delivery Service	1,814	91,067	17	5,357	0.0502
21	14.08 Air Conditioning Control Rider		(5,717)			
22	14.09 Voluntary Renewable Energy Rider		3,309	4	827	
23	14.1 WAPA Bill Crediting Program Rider		(350,159)	4		
24	14.12 Off-Peak Electric Vehicle Rider	3	176			
25	Other	(58)	217,668	(a)(389)	(560)	(3.7529)
41	TOTAL Billed Large (or Ind.) Sales	3,399,737	217,912,770	830	4,096,069	0.0641
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	3,997	(6,927,709)			(1.7332)
43	TOTAL Large (or Ind.)	3,403,734	210,985,061	830	4,100,884	0.0620

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
Average number of customers are included within the Commercial (Large) Service categories listed.
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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4			
SALES OF ELECTRICITY BY RATE SCHEDULES						
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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	4,123	405,040	239	1,695	0.0982
3	11.04 Outdoor Lighting	4,981	966,225	159	6,077	0.1940
4	11.07 LED Street and Area Lighting	4,692	2,852,958	260	10,973	0.6080
5	Adjustment	(8)	3,838			(0.4798)
41	TOTAL Billed Public Street and Highway Lighting	13,788	4,228,061	658	20,954	0.3066
42	TOTAL Unbilled Rev. (See Instr. 6)	(12)	(110,016)			9.1680
43	TOTAL	13,776	4,118,045	658	20,936	0.2989

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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	11.03 Outdoor Lighting - Energy Only	29	3,352	5	670	0.1156
3	11.04 Outdoor Lighting	10	2,170	5		0.2170
4	11.05 Municipal Pumping Service	41,140	3,753,182	1,100	3,412	0.0912
5	11.06 Fire Sirens		11,879	97		
6	11.07 LED Street and Area Lighting	5	2,732	5	546	0.5464
7	14.04 Controlled Service - Interruptible Load	556	26,980	4	6,745	0.0485
8	14.05 Controlled Service - Interruptible Load	265	14,825	9		0.0559
9	14.06 Controlled Service - Deferred Load	55	4,224	1	4,224	0.0768
10	14.07 Fixed Time of Delivery Service	19	1,242	3		0.0654
11	Other	319	56,262			0.1764
41	TOTAL Billed Other Sales to Public Authorities	42,398	3,876,848	1,229	34,498	0.0914
42	TOTAL Unbilled Rev. (See Instr. 6)	88	(185,758)			(2.1109)
43	TOTAL	42,486	3,691,090	1,229	34,570	0.0869

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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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	^(a) Revenue from Fuel Adjustment					
2	Clause is reported in footnote.					
3	Provision for Rate Refunds		(365,767)			
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		(365,767)			

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	\$18,657,422
1 Residential	9.02 Residential Demand Control Service	\$2,605,095
1 Residential	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn	\$1,584
1 Residential	11.04 Outdoor Lighting - Dusk to Dawn	\$22,637
1 Residential	11.07 LED Street and Area Lighting	\$11,034
1 Residential	14.01 Water Heating Control Rider	\$631,647
1 Residential	14.04 Controlled Service - Interruptible Load - CT Metering Rider	\$4,567
1 Residential	14.05 Controlled Service - Interruptible Load - Self-Contained Metering Rider	\$3,277,422
1 Residential	14.06 Controlled Service - Deferred Load Rider	\$234,417
1 Residential	14.07 Fixed Time of Service Rider	\$116,471
1 Residential	14.12 Off-Peak Electric Vehicle Rider	\$2,302
Total Residential		\$25,564,598
Commercial and industrial - 442		
2 Commercial	9.01 Residential Service	\$19,793
2 Commercial	9.03 Farm Service	\$1,556,286
2 Commercial	10.01 Small General Service Under 20 kW	\$4,428,127
2 Commercial	10.02 General Service 20 kW or Greater	\$12,071,646
2 Commercial	10.03 General Service - Time Of Use	\$10,842,820
2 Commercial	10.04 Large General Service	\$10,668,546
2 Commercial	10.05 Large General Service - Time Of Day	\$24,482,478
2 Commercial	10.06 Super Large General Service	\$13,808,435
2 Commercial	10.07 EV DCFE General Service - Time of Day	\$6,690
2 Commercial	11.01 Standby Service	\$2,623
2 Commercial	11.02 Irrigation Service	\$74,364
2 Commercial	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn	\$33,801
2 Commercial	11.04 Outdoor Lighting - Dusk to Dawn	\$71,609
2 Commercial	11.07 LED Street and Area Lighting	\$59,158
2 Commercial	14.01 Water Heating Control Rider	\$32,990
2 Commercial	14.03 Large General Service Rider	\$6,964,319
2 Commercial	14.04 Controlled Service - Interruptible Load - CT Metering Rider	\$2,043,087
2 Commercial	14.05 Controlled Service - Interruptible Load - Self-Contained Metering Rider	\$1,204,590
2 Commercial	14.06 Controlled Service - Deferred Load Rider	\$433,296
2 Commercial	14.07 Fixed Time of Service Rider	\$499,610
2 Commercial	14.12 Off-Peak Electric Vehicle Rider	\$668
2 Commercial	Other	\$9
Total Commercial and industrial		\$89,304,945
Streetlighting		
4 Streetlighting	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn	\$69,625
4 Streetlighting	11.04 Outdoor Lighting - Dusk to Dawn	\$78,874
4 Streetlighting	11.07 LED Street and Area Lighting	\$78,805
Total Streetlighting		\$227,304
Other public authority - 445		
5 OPA	11.03 Outdoor Lighting - Energy Only - Dusk to Dawn	\$463
5 OPA	11.04 Outdoor Lighting - Dusk to Dawn	\$164
5 OPA	11.05 Municipal Pumping Service	\$856,586
5 OPA	11.07 LED Street and Area Lighting	\$78
5 OPA	14.04 Controlled Service - Interruptible Load - CT Metering Rider	\$11,894
5 OPA	14.05 Controlled Service - Interruptible Load - Self-Contained Metering Rider	\$5,851
5 OPA	14.06 Controlled Service - Deferred Load Rider	\$1,238
5 OPA	14.07 Fixed Time of Service Rider	\$353
Total Other public authority		\$876,627
TOTAL Billed FCA Revenue		\$115,973,474

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4			
SALES OF ELECTRICITY BY RATE SCHEDULES						
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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	5,655,566	473,705,920	135,519	41,733	0.0838
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	25,702	(22,986,705)			(0.8944)
43	TOTAL - All Accounts	5,681,268	450,719,215	135,519	41,922	0.0793

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 exchange during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc) any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 401).
- Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any owners 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 in projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or set 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 reason 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 transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller 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. Include 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 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 sales 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 meter 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 reported 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 (l)
					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	0.35			133	17,128	4,355	60	
3	Newfolden, MN	RQ	174	0.36			1,873	17,713	63,313	3,775	
4	Nielsville, MN	RQ	175	0.06			64	424	2,184	132	
5	Shelly, MN	RQ	176	0.18			500	12,336	15,621	1,004	
6	NON-RQ SALES										
7	Midwest ISO Energy Market	OS	V9				298,649		10,939,105		10,9
15	Subtotal - RQ						2,570	47,601	85,473	4,971	
16	Subtotal- Non-RQ						298,649		10,939,105		10,9
17	Total						301,219	47,601	11,024,578	4,971	11,0

FERC FORM NO. 1 (ED. 12-90)

Page 310-311

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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

FERC FORM NO. 1 (ED. 12-90)

Page 310-311

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	1,309,296	1,318,672	
5	(501) Fuel	46,240,823	43,998,317	
6	(502) Steam Expenses	5,203,212	4,660,979	
7	(503) Steam from Other Sources			
8	(Less) (504) Steam Transferred-Cr.			
9	(505) Electric Expenses	1,689,387	1,650,981	
10	(506) Miscellaneous Steam Power Expenses	4,852,237	3,844,208	
11	(507) Rents	22,288	5,006	
12	(509) Allowances			
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	59,317,243	55,478,163	
14	Maintenance			
15	(510) Maintenance Supervision and Engineering	519,606	551,458	
16	(511) Maintenance of Structures	928,953	769,295	
17	(512) Maintenance of Boiler Plant	5,707,751	5,798,533	
18	(513) Maintenance of Electric Plant	506,162	1,460,691	
19	(514) Maintenance of Miscellaneous Steam Plant	1,158,550	1,103,508	
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,821,022	9,683,485	
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	68,138,265	65,161,648	
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	16,015	15,009
45	(536) Water for Power		
46	(537) Hydraulic Expenses	5,592	3,266
47	(538) Electric Expenses	121	154
48	(539) Miscellaneous Hydraulic Power Generation Expenses	35,950	22,558
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	57,678	40,987
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	3	6,999
54	(542) Maintenance of Structures	12,394	3,353
55	(543) Maintenance of Reservoirs, Dams, and Waterways	266,369	232,540
56	(544) Maintenance of Electric Plant	36,490	8,209
57	(545) Maintenance of Miscellaneous Hydraulic Plant	9,966	23,304
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	325,222	274,405
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	382,900	315,392
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	478,985	324,560

63	(547) Fuel	14,981,246	16,592,984
64	(548) Generation Expenses	4,120,995	3,501,089
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	3,382,800	3,501,451
66	(550) Rents	1,793,886	1,833,638
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	24,757,912	25,753,722
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	41,486	23,925
70	(552) Maintenance of Structures	67,804	49,766
71	(553) Maintenance of Generating and Electric Plant	5,650,700	5,252,733
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	273,840	811,540
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	6,033,830	6,137,964
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	30,791,742	31,891,686
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	61,561,128	78,291,775
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	449,844	436,672
78	(557) Other Expenses	41,983	45,083
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	62,052,955	78,773,530
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	161,365,862	176,142,256
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	158,932	161,483
85	(561.1) Load Dispatch-Reliability	71,084	70,936
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,175,345	2,144,552
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,272,983	1,051,162
89	(561.5) Reliability, Planning and Standards Development	485,430	418,245
90	(561.6) Transmission Service Studies	1,069	13,789
91	(561.7) Generation Interconnection Studies	3,354	
92	(561.8) Reliability, Planning and Standards Development Services		
93		403,959	413,014

	(562) Station Expenses		
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	254,215	294,619
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	23,477,129	24,751,740
97	(566) Miscellaneous Transmission Expenses	1,164,656	612,718
98	(567) Rents	80,360	72,876
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	29,548,516	30,005,134
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	424,711	260,881
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	227,954	98,822
104	(569.2) Maintenance of Computer Software	739,779	886,216
105	(569.3) Maintenance of Communication Equipment	60,302	65,937
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,405,182	1,237,569
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	2,898,946	2,786,293
109	(572) Maintenance of Underground Lines	18	576
110	(573) Maintenance of Miscellaneous Transmission Plant	143	425,508
111	TOTAL Maintenance (Total of Lines 101 thru 110)	5,757,035	5,761,802
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	35,305,551	35,766,936
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	864,824	741,632
117	(575.3) Transmission Rights Market Facilitation	6,787	6,821
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	25,399	21,559
120	(575.6) Market Monitoring and Compliance	2,497	1,490
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	899,507	771,502
124	Maintenance		

125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	247,475	246,956
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	247,475	246,956
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	1,146,982	1,018,458
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	352,591	346,927
135	(581) Load Dispatching	145,313	85,201
136	(582) Station Expenses	336,252	349,208
137	(583) Overhead Line Expenses	318,947	240,219
138	(584) Underground Line Expenses	1,989,452	1,683,904
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	8	1,193
140	(586) Meter Expenses	1,303,380	991,468
141	(587) Customer Installations Expenses	14,818	3,163
142	(588) Miscellaneous Expenses	4,466,370	4,523,753
143	(589) Rents	201,760	205,605
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	9,128,891	8,430,641
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,598,384	1,084,783
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	872,036	704,515
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	5,914,769	7,625,101
150	(594) Maintenance of Underground Lines	721,402	786,820
151	(595) Maintenance of Line Transformers	236,510	171,171
152	(596) Maintenance of Street Lighting and Signal Systems	160,887	134,781
153	(597) Maintenance of Meters	594,848	1,063,452
154	(598) Maintenance of Miscellaneous Distribution Plant	91,860	134,777
155	TOTAL Maintenance (Total of Lines 146 thru 154)	10,190,696	11,705,400
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	19,319,587	20,136,041
157	5. CUSTOMER ACCOUNTS EXPENSES		

158	Operation		
159	(901) Supervision	94,314	30,045
160	(902) Meter Reading Expenses	4,484,347	6,063,885
161	(903) Customer Records and Collection Expenses	5,598,899	6,249,715
162	(904) Uncollectible Accounts	1,211,559	1,307,083
163	(905) Miscellaneous Customer Accounts Expenses	1,024,822	1,017,563
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	12,413,941	14,668,291
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	1,126,545	724,242
168	(908) Customer Assistance Expenses	9,741,181	10,010,491
169	(909) Informational and Instructional Expenses	112,800	145,028
170	(910) Miscellaneous Customer Service and Informational Expenses	102,896	91,766
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	11,083,422	10,971,527
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	8,613	9,034
175	(912) Demonstrating and Selling Expenses	339,023	426,603
176	(913) Advertising Expenses	4	1,196
177	(916) Miscellaneous Sales Expenses	6,328	5,444
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	353,968	442,277
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	31,748,663	29,701,057
182	(921) Office Supplies and Expenses	11,855,696	11,685,648
183	(Less) (922) Administrative Expenses Transferred-Credit	2,647,494	2,531,974
184	(923) Outside Services Employed	3,830,043	2,935,383
185	(924) Property Insurance	2,949,608	3,450,645
186	(925) Injuries and Damages	3,107,304	3,262,606
187	(926) Employee Pensions and Benefits	1,165,675	1,098,364
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,030,432	2,346,607
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	882,738	735,055

192	(930.2) Miscellaneous General Expenses	1,083,870	1,308,371
193	(931) Rents	300,451	344,035
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	57,306,986	54,335,797
195	Maintenance		
196	(935) Maintenance of General Plant	2,857,792	2,613,437
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	60,164,778	56,949,234
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	301,154,091	316,095,020

FERC FORM NO. 1 (ED. 12-93)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
\$504,081 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.
(b) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
\$560,184 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

FERC FORM NO. 1 (ED. 12-93)

Page 320-323

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

PURCHASED POWER (Account 555)

- Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and settlements for imbalanced exchanges).
- 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 acronym affiliation the respondent has with the seller.
- 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 in 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

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic or adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category is for a 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 and the date the 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 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 are determined by the availability and reliability of the 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.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and 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 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. For each adjustment, provide an explanatory footnote.

- In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other services, enter the monthly average monthly coincident peak (CP) demand in column (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the maximum metered hourly (60-minute integration) demand in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote explain.
- Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, respectively.
- 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). Report in column (n) the total charge shown on bills received as settlement by the respondent for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount includes incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
- 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 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 12.
- 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	Tidal Energy Marketing	SF					187,400			
2	Western Area Power Administration	EX					439			

3	Western Area Power Administration - WEC	OS					28,632			
4	Beltrami Electric Cooperative	RQ					109,925			
5	Nodak Rural Electric Cooperative	RQ					6,531			
6	PKM Electric Cooperative	RQ					6,635			
7	Red Lake Rural Electric Cooperative	RQ					6,609			
8	Cass County Electric Cooperative	OS					67			
9	Whetstone Valley Electric Cooperative	OS								
10	City of Detroit Lakes	OS					812			
11	Kindred School	RQ								
12	Stevens Community Medical	RQ								
13	American Crystal Sugar	OS					55			
14	Hendricks Wind I	RQ					2,053			
15	Borderline Wind	RQ					1,961			
16	University of MN - Morris	RQ					3,723			
17	Lac Qui Parle Valley High School	RQ					42			
18	Lake Region State College	RQ					2,486			
19	conEdison Development RLF Community Hybrid, LLC	RQ					14,448			
20	FPL Energy ND Wind II, LLC	RQ					51,981			
21	Langdon Wind, LLC	RQ					63,231			
22	Langdon Wind, LLC - Curtailment	RQ					4,558			
23		OS					1,170			

	MN Co Generation									
24	ND Co Generation	OS					151			
25	SD Co Generation	OS					23			
26	Shared Loads	OS		0						
27	Midwest ISO Energy Market	OS					2,519,205			
28	Southwest Power Pool ISO Energy Market	OS					456			
15	TOTAL						3,012,593	0	0	0

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: OtherChargesOfPurchasedPower
Nomination charge
FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions refer

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilit 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 or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate 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 - F Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for a 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.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for the substation.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported 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; (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all of adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the a
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purpose
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)	TRAN: ENI
									Megawatt Hours Received (i)
1	Badger, SD	Western Area Power Administration	Badger, SD	LFP	4	(1)	Badger, SD		1,411
2	Newfolden, MN	Western Area Power Administration	Newfolden, MN	LFP	4	(1)	Newfolden, MN		2,848
3	Nielsville, MN	Western Area Power Administration	Nielsville, MN	LFP	4	(1)	Nielsville, MN		557
4	Shelly, MN	Western Area Power Administration	Shelly, MN	LFP	4	(1)	Shelly, MN		1,425
5	Fort Totten Indian Agency	Western Area Power Administration	Fort Totten, ND	LFP	4	(1)	Fort Totten, ND		282
6	State Development Center	Western Area Power Administration	Grafton, ND	LFP	4	(1)	Grafton, ND		4,438
7	North Dakota School for Deaf	Western Area Power Administration	Devils Lake, ND	LFP	4	(1)	Devils Lake, ND		435
8	North Dakota School of Forestry	Western Area Power Administration	Bottineau, ND	LFP	4	(1)	Bottineau, ND		1,120

9	North Dakota College of Science	Western Area Power Administration	Wahpeton, ND	LFP	4	(1)	Wahpeton, ND		7,831
10	Turtle Mountain Indian Agency	Western Area Power Administration	Belcourt, ND	LFP	4	(1)	Belcourt, ND		2,322
11	Oakes O&M Headquarters	Western Area Power Administration	Oakes, ND	LFP	4	(1)	Oakes, ND		51
12	Minnkota Power Cooperative, Inc.	Minnkota Power Cooperative, Inc.	Various Interconnects	OS	See Footnote	(1)	Various Interconnects		220,555
13		U.S. Bureau of Reclamation	Otter Tail Power Company	OS	—	—	(1)		402
14		(a) Various Companies	Otter Tail Power Company	OS	—	—	(1)		(271,906)
15		(a) Various Companies	Otter Tail Power Company	OS	—	—	(1)		(402)
16		Various Companies	Various Companies	OS			Various Interconnects		
17	(a) Midwest Independent System Operator	Various Companies	Various Companies	OS	OATT	(a) System	System		0
18	See Footnote					See Footnote			0
35	TOTAL							0	(28,631)

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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 - 16 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: TransmissionPointOfReceipt

(1) Various points of interconnect in the integrated system

(e) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Midwest Independent System Operator Transmission

FERC FORM NO. 1 (ED. 12-90)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4		
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				

FERC FORM NO. 1 (REV 03-07)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4					
TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)								
1. 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. 2. 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. 3. 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. 4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service. 5. 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. 6. Enter ""TOTAL"" in column (a) as the last line. 7. 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					22,660,928	22,660,928
2	Montana-Dakota Utilities Co.	OS					777,612	777,612
3	Central Power Electric Cooperative, Inc	FNS				25,726		25,726
4	PKM Electric Coop Inc.	FNS		549		2,827		2,827
5	Dakota Valley Electric Cooperative	FNS				10,036		10,036
	TOTAL		0	549	0	38,589	23,438,540	23,477,129

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.

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

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)				
Line No.	Description (a)	Amount (b)		
1	Industry Association Dues	356,953		
2	Nuclear Power Research Expenses			
3	Other Experimental and General Research Expenses	95,154		
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	87,941		
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000			
6	Miscellaneous labor	116,602		
7	Director Fees and Expense:	398,528		
8	Public Relations Expenses:			
9	Labor	9,138		
10	Items less than \$5,000 each	19,554		
11	Strategic Planning Expenses:			
12	Labor			
46	TOTAL	1,083,870		

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4			
Depreciation and Amortization of Electric Plant (Account 403, 404, 405)						
1. 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). 2. 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. 3. 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. 4. 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.						
Line No.	A. Summary of Depreciation and Amortization Charges					
	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			6,341,272		6,341,272
2	Steam Production Plant	15,048,536	348,697			15,397,233
3	Nuclear Production Plant					
4	Hydraulic Production Plant- Conventional	161,239				161,239
5	Hydraulic Production Plant- Pumped Storage					
6	Other Production Plant	27,050,245	690,522			27,740,767
7	Transmission Plant	12,151,271				12,151,271
8	Distribution Plant	17,222,056				17,222,056
9	Regional Transmission and Market Operation					
10	General Plant	3,461,274				3,461,274
11	Common Plant-Electric					
12	TOTAL	75,094,621	1,039,219	6,341,272		82,475,112
B. Basis for Amortization Charges						
The \$6,341,272 Amortization of limited term Electric Plant is: Franchise Consents (302): \$49,961 for hydro plant license with a remaining life of 38 years at a rate of 2.50% Miscellaneous Intangible Plant (303): \$3,300,135 for computer software with a 5-year service life at a rate of 20.0% \$2,991,176 for computer software with a 10-year service life at a rate of 10.0%						
C. Factors Used in Estimating Depreciation Charges						
Account No.						

Line 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	44,318	34 years, 6 months, 7 days	(5.8)	2.78	SQ	21 years, 9 months, 15 days
15	312	142,255	32 years, 4 months, 21 days	(5.8)	3.51	SQ	21 years, 9 months, 15 days
16	314	10,844	41 years, 5 months, 23 days	(5.8)	1.83	SQ	21 years, 9 months, 7 days
17	315	10,301	36 years, 7 months, 28 days	(5.8)	2.51	SQ	21 years, 9 months, 11 days
18	316	1,980	36 years, 6 months, 11 days	(5.8)	2.78	SQ	21 years, 9 months, 11 days
19	Hoot Lake Plant -						
20	312.1 - Units 2, 3	6,771	35 years, 11 months, 19 days		2.28	SQ	26 years, 5 months, 16 days
21	Coyote Plant -						
22	311	7,043	49 years, 2 months, 23 days	(8.6)	1.69	SQ	17 years, 11 days
23	312	35,428	39 years, 3 months, 22 days	(8.6)	2.44	SQ	17 years, 15 days
24	314	10,615	37 years, 2 months, 16 days	(8.6)	2.88	SQ	17 years, 18 days
25	315	2,716	46 years, 6 months, 15 days	(8.6)	1.81	SQ	17 years, 15 days
26	316	1,307	29 years, 3 months, 22 days	(8.6)	3.66	SQ	17 years, 22 days
27	STEAM PROD	273,578					
28	Hydro Production -						
29	Hoot Lake Hydro -						
30	331	769	97 years, 2 months, 27 days		1.5	SQ	36 years, 1 month, 24 days
31	332	74	49 years, 29 days		0.52	SQ	36 years, 5 months, 23 days
32	333	1	72 years, 10 months, 28 days		0.03	SQ	36 years, 4 months, 2 days
33	334	1,147	40 years, 4 days		2.58	SQ	36 years, 6 months, 15 days
34	335	(41)	47 years, 4 days		(0.39)	SQ	36 years, 6 months
35	Wright Hydro -						
36	331	1			0.2	SQ	

			69 years, 10 months, 6 days				36 years, 4 months, 6 days
37	332	148	51 years, 8 months, 12 days		0.42	SQ	36 years, 5 months, 19 days
38	333	15	48 years, 11 months, 23 days		0.08	SQ	36 years, 5 months, 27 days
39	334	8	55 years, 3 months, 7 days		0.11	SQ	36 years, 5 months, 12 days
40	335	7	53 years, 1 month, 17 days		0.17	SQ	36 years, 5 months, 16 days
41	Pisgah Hydro -						
42	331	1	72 years, 10 months, 17 days		0.26	SQ	36 years, 3 months, 29 days
43	332	2,574	41 years, 11 months, 12 days		3.22	SQ	36 years, 6 months, 7 days
44	333	8	54 years, 2 months, 12 days		0.14	SQ	36 years, 5 months, 12 days
45	334	5	53 years, 11 months, 16 days		0.13	SQ	36 years, 5 months, 12 days
46	335	6	47 years, 4 days		0.24	SQ	36 years, 6 months
47	Dayton Hollow Hydro -						
48	331	180	39 years, 10 months, 21 days		2.72	SQ	36 years, 6 months, 15 days
49	332	1,272	44 years, 8 months, 9 days		1.64	SQ	36 years, 6 months, 4 days
50	333	11	53 years, 1 month, 10 days		0.13	SQ	36 years, 5 months, 16 days
51	334	7	59 years, 8 months, 16 days		0.09	SQ	36 years, 5 months, 1 day
52	335	9	47 years, 4 days		0.22	SQ	36 years, 6 months
53	Taplin Gorge Hydro -						
54	331		108 years, 11 months, 9 days		0.02	SQ	36 years, 22 days
55	332	129	62 years, 4 months, 10 days		0.5	SQ	36 years, 4 months, 21 days
56	333		113 years, 8 months, 16 days		0.02	SQ	36 years, 11 days
57	334	2	63 years, 4 days		0.08	SQ	36 years, 4 months, 24 days
58	335	6	51 years, 5 months, 19 days		0.17	SQ	36 years, 5 months, 19 days
59	Bemidji Hydro -						
60	331					SQ	
61	332					SQ	
62	333					SQ	

63	334					SQ	
64	335					SQ	
65	HYDRO PROD	6,339					
66	Other Production -						
67	Jamestown Peaking #1 -						
68	341	37	35 years, 10 months, 21 days	(6.2)	2.03	SQ	9 years, 4 months, 6 days
69	342	86	28 years, 3 months, 22 days	(6.2)	3.08	SQ	9 years, 4 months, 10 days
70	343	489	38 years, 15 days	(6.2)	2.33	SQ	9 years, 4 months, 6 days
71	345	17	56 years, 4 months, 13 days	(6.2)	1.82	SQ	9 years, 4 months, 2 days
72	346	25	22 years, 5 months, 1 day	(6.2)	3.73	SQ	9 years, 4 months, 10 days
73	Lake Preston Peaking -						
74	341	74	27 years, 9 months, 15 days	(7.1)	3.59	SQ	9 years, 4 months, 10 days
75	342	31	39 years, 10 months, 24 days	(7.1)	1.77	SQ	9 years, 4 months, 6 days
76	343	450	43 years, 3 months, 11 days	(7.1)	2.14	SQ	9 years, 4 months, 6 days
77	345	34	42 years, 3 months, 15 days	(7.1)	1.66	SQ	9 years, 4 months, 6 days
78	346	1	48 years, 9 months, 26 days	(7.1)	1.02	SQ	9 years, 4 months, 6 days
79	Jamestown Peaking #2 -						
80	341	6	27 years, 8 months, 19 days	(6.2)	3.12	SQ	9 years, 4 months, 10 days
81	342	3	30 years, 2 months, 9 days	(6.2)	1.41	SQ	9 years, 4 months, 6 days
82	343	429	43 years, 4 months, 13 days	(6.2)	1.8	SQ	9 years, 4 months, 6 days
83	345	25	21 years, 3 months, 7 days	(6.2)	4.35	SQ	9 years, 4 months, 10 days
84	346		45 years, 11 months, 16 days	(6.2)	(0.15)	SQ	9 years, 4 months, 6 days
85	Fergus Falls Control Center -						
86	343					SQ	
87	Solway Combustion Turbine -						
88	341	2,229	31 years, 3 months, 4 days	(1.6)	3.31	SQ	14 years, 2 months, 9 days

89	342	513	27 years, 15 days	(1.6)	3.38	SQ	14 years, 2 months, 9 days
90	343	12,535	29 years, 11 months, 23 days	(1.6)	4.14	SQ	14 years, 2 months, 9 days
91	345	571	32 years, 4 months, 13 days	(1.6)	3.19	SQ	14 years, 2 months, 9 days
92	346	151	29 years, 9 months, 7 days	(1.6)	3.45	SQ	14 years, 2 months, 9 days
93	Astoria Station -						
94	341	23,446	33 years, 5 months, 19 days	(2.2)	3.03	SQ	31 years, 1 month, 2 days
95	342	5,441	33 years, 5 months, 19 days	(2.2)	3.03	SQ	31 years, 1 month, 2 days
96	343	99,411	33 years, 5 months, 19 days	(2.2)	3.03	SQ	31 years, 1 month, 2 days
97	345	6,801	33 years, 5 months, 19 days	(2.2)	3.03	SQ	31 years, 1 month, 2 days
98	346	1,360	33 years, 5 months, 19 days	(2.2)	3.03	SQ	31 years, 1 month, 2 days
99	Langdon Wind Energy Center -						
100	341	997	33 years, 9 months, 7 days	(7.6)	2.65	SQ	18 years, 4 days
101	344	30,107	33 years, 7 days	(7.6)	2.83	SQ	18 years, 4 days
102	345	3,949	33 years, 3 months, 26 days	(7.6)	3.05	SQ	18 years, 4 days
103	346	119	22 years, 5 months, 12 days	(7.6)	6	SQ	18 years, 7 days
104	Ashtabula Wind Energy Center -						
105	341	1,425	33 years, 8 months, 23 days	(6.3)	2.65	SQ	18 years, 11 months, 16 days
106	344	49,931	33 years, 1 month, 10 days	(6.3)	2.82	SQ	18 years, 11 months, 16 days
107	345	2,887	33 years, 4 months, 28 days	(6.3)	2.68	SQ	18 years, 11 months, 16 days
108	346	104	22 years, 5 months, 23 days	(6.3)	5.63	SQ	18 years, 11 months, 19 days
109	Luverne Wind Energy Center -						
110	341	1,051	33 years, 8 months, 12 days	(10.2)	2.84	SQ	19 years, 10 months, 24 days
111	344	35,559	32 years, 6 months, 15 days	(10.2)	3.17	SQ	19 years, 10 months, 24 days
112	345	2,256	33 years, 8 months, 9 days	(10.2)	2.84	SQ	19 years, 10 months, 24 days
113	346	145	24 years, 3 months, 11 days	(10.2)	5.39	SQ	19 years, 11 months, 1 day
114							

	Merricourt Wind Energy Center -						
115	341	7,220	33 years, 5 months, 23 days	(8.5)	3.29	SQ	30 years, 2 months, 1 day
116	344	212,415	33 years, 5 months, 23 days	(8.5)	3.28	SQ	30 years, 2 months, 1 day
117	345	16,521	33 years, 5 months, 23 days	(8.5)	3.28	SQ	30 years, 2 months, 1 day
118	346	59	31 years, 7 months, 21 days	(8.5)	3.56	SQ	30 years, 2 months, 5 days
119	Ashtabula III Wind Energy Center -						
120	341	2,559	36 years, 4 months, 21 days	(12.5)	3.21	SQ	23 years, 7 months, 28 days
121	344	44,152	36 years, 4 months, 21 days	(12.5)	3.17	SQ	23 years, 7 months, 28 days
122	345	4,416	36 years, 4 months, 21 days	(12.5)	3.19	SQ	23 years, 7 months, 28 days
123	346	165	36 years, 4 months, 21 days	(12.5)	3.66	SQ	23 years, 7 months, 28 days
124	Hoot Lake Solar -						
125	341	1,822	35 years	(12.1)	3.22	SQ	34 years, 6 months
126	345	56,489	35 years	(12.1)	3.22	SQ	34 years, 6 months
127	346	607	35 years	(12.1)	3.22	SQ	34 years, 6 months
128	Minnesota Dakota Small Solar -						
129	341	12	24 years, 2 months, 23 days	(1)	4.23	SQ	20 years, 10 months, 10 days
130	345	124	24 years, 2 months, 23 days	(1)	4.23	SQ	20 years, 10 months, 10 days
131	North Dakota Small Solar -						
132	341	15	24 years, 2 months, 23 days	(1)	4.13	SQ	20 years, 10 months, 10 days
133	345	129	24 years, 2 months, 23 days	(1)	4.13	SQ	20 years, 10 months, 10 days
134	OTHER PROD	629,400					
135	Transmission Plant -						
136	350.1	19,732	70 years		1.43		
137	353	154,233	65 years, 1 month, 13 days	(5)	1.54	R1	56 years, 18 days
138	354	174,954	80 years	(10)	1.35	R5	73 years, 2 months, 27 days
139	355	112,387	80 years, 2 months, 5 days	(50)	1.75	R2	65 years, 5 months, 19 days

140	356	140,478	80 years, 15 days	(30)	1.53	R2	67 years, 3 months, 15 days
141	358	(2)	51 years, 2 months, 1 day	(5)	0.14	S4	21 years, 2 months, 16 days
142	SUBTOTAL	601,782					
143	Distribution Plant -						
144	362	72,270	45 years, 4 months, 24 days	5	1.84	SC	36 years, 4 months, 6 days
145	364	37,163	72 years, 26 days	(125)	3.29	R3	50 years, 5 months, 27 days
146	365	17,165	68 years, 1 month, 17 days	(70)	2.11	R2.5	46 years, 18 days
147	367	87,785	50 years, 26 days	(5)	1.94	S2	36 years, 3 months, 29 days
148	368	112,322	44 years, 11 months, 1 day	30	1.62	S1.5	32 years, 6 months, 22 days
149	369	(5,089)	60 years, 1 month, 17 days	(300)	7.9	S4	33 years, 5 months, 23 days
150	369.1	27,569	55 years, 29 days	(50)	2.77	R4	37 years, 2 months, 5 days
151	370	16,538	31 years, 18 days		2.85	L1	20 years, 5 months, 16 days
152	370.05	700	20 years		4.88	S3	15 years, 6 months, 26 days
153	370.1	14	20 years, 2 months, 16 days		0.04	R5	3 years, 8 months, 19 days
154	370.2		5 years		20	SQ - Amortized	0 days
155	371.1	16	10 years		10	SQ - Amortized	6 years, 6 months
156	371.2	9,438	20 years, 11 months, 9 days	(5)	5.61	L0	17 years, 4 months, 28 days
157	373	12,899	20 years, 1 month, 13 days	(10)	5.98	L1	16 years, 5 months, 19 days
158	SUBTOTAL	388,790					
159	General Plant -						
160	390	17,744	51 years, 15 days		2.01	R1	33 years, 8 months, 27 days
161	390.1	3,774	37 years, 9 months, 29 days	46.7	0.73	SQ	16 years, 1 month, 2 days
162	390.2	463	46 years, 9 months, 4 days	71.1	(0.94)	SQ	20 years, 9 months, 26 days
163	390.25	2,044	55 years, 6 months, 4 days	152.3	(1.12)	SQ	51 years, 5 months, 19 days
164	390.3	2,987	54 years, 11 months, 27 days	87.9	(1.03)	SQ	20 years, 9 months, 22 days
165	391	135	15 years		6.67	SQ - Amortized	3 years, 9 months, 26 days
166	391.1	91	10 years		10	SQ - Amortized	4 years, 26 days

167	391.2	638	10 years		10	SQ - Amortized	5 years, 9 months, 26 days
168	391.5	2,090	5 years		20	SQ - Amortized	2 years, 2 months, 12 days
169	391.6	1,079	5 years		20	SQ - Amortized	1 year, 11 months, 9 days
170	392	20,657					
171	Aircraft	1,480	10 years				
172	Autos		5 years	15			
173	Light Trucks		10 years	10			
174	Heavy Trucks & Semi		10 years	15			
175	Tractors (Includes Cranes)		10 years	15			
176	Trailers		15 years	10			
177	Portable Oil Purifier		10 years	20			
178	Trenchers		10 years	10			
179	Misc. Light Equip.		10 years	10			
180	Misc. Heavy Equip.		15 years	15			
181	394	3,094	15 years		6.67	SQ - Amortized	7 years, 7 months, 28 days
182	394.2	255	15 years		6.67	SQ - Amortized	10 years, 8 months, 23 days
183	395		15 years		6.67	SQ - Amortized	0 days
184	396	1,333	22 years, 2 months, 9 days	5	4.12	L1.5	17 years, 3 months, 15 days
185	397	3,143	15 years		6.67	SQ - Amortized	9 years, 8 months, 9 days
186	397.1	156	10 years		10	SQ - Amortized	7 years, 10 months, 6 days
187	397.2	1,671	15 years		6.67	SQ - Amortized	6 years, 6 months, 4 days
188	397.3	63	10 years		10	SQ - Amortized	4 years, 3 months
189	397.4	828	50 years, 6 months, 15 days	(5)	1.63	R2.5	29 years, 5 months, 5 days
190	SUBTOTAL	63,725					
191	TOTAL	1,963,614					
192	 SUBACCOUNTS USED						

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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.

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized 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.
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.

						EXPENSES INCURRED DURING YEAR				AM
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)	CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Cont Acco (j)
						Department (f)	Account No. (g)	Amount (h)		
1	MN Dept. of Commerce/Public Utilities Commission	990,205		990,205		Electric	928	990,205		
2	E017/M-24-422 - MN RRCRR 2024		16,645	16,645	754,187	Electric	928	16,645		
3	E017/M-24-186 - MN 2024 EUIC		24,330	24,330		Electric	928	24,330		
4	E017-RP-21-339 - Integrated Resource Plan 2022-2036		133,627	133,627		Electric	928	133,627		
5	E017-M-21-382; E017-M-23-131 (MN Electric Utility Infrastructure Costs)		4,628	4,628		Electric	928	4,628		
6	E999/AA-18-373 - MN 2024 Transmission Cost Recovery		25,548	25,548		Electric	928	25,548		
7	M-23-261 - MN TOD Pilot		53,051	53,051		Electric	929	53,051		
8	E017/M-24-30 - MN 2023 SRSQ		26,099	26,099		Electric	928	26,099		
9	Miscellaneous - MN		249,157	249,157		Electric	928	249,157		
10	ND Public Service Commission	50,048		50,048		Electric	928	50,048		
11	PU-17-398 (ND Rate Case)		247,505	247,505	898,995	Electric	928	247,505		

12	PU-24-076 ND On-Bill REC Program		5,314	5,314		Electric	928	5,314		
13	PU-23-306; PU-19-17 - ND TCR		6,478	6,478		Electric	928	6,478		
14	Miscellaneous - ND		17,818	17,818		Electric	928	17,818		
15	SD Public Service Commission	75,054		75,054		Electric	928	75,054		
16	EL23-033 (SD TCR)		13,807	13,807		Electric	928	13,807		
17	EL23-015 - Phase In Rider		48,650	48,650		Electric	928	48,650		
18	Miscellaneous - SD		5,108	5,108		Electric	928	5,108		
19	Federal Energy Regulatory Commission:									
20	MISO Schedule 10		542,909	542,909		Electric	928	542,909		
21	SPP Schedule 12		22,399	22,399		Electric	928	22,399		
22	North American Electric Reliability Corporation	393,207		393,207		Electric	928	393,207		
23	FERC/RTO Policy		78,845	78,845		Electric	928	78,845		
46	TOTAL	1,508,514	1,521,918	3,030,432	1,653,182			3,030,432		

FERC FORM NO. 1 (ED. 12-96)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: DeferredRegulatoryCommissionExpensesAmortized
Amortized period is Jan 2021 through Dec 2025
(b) Concept: DeferredRegulatoryCommissionExpensesAmortized
Amortized period is Jan 2024 through Dec 2027

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4																										
RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES																													
1. 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). 2. Indicate in column (a) the applicable classification, as shown below: Classifications: <table border="0"> <tr> <td>Electric R, D and D Performed Internally:</td> <td>Overhead Underground</td> </tr> <tr> <td> Generation</td> <td>Distribution</td> </tr> <tr> <td> hydroelectric</td> <td>Regional Transmission and Market Operation</td> </tr> <tr> <td> Recreation fish and wildlife</td> <td>Environment (other than equipment)</td> </tr> <tr> <td> Other hydroelectric</td> <td>Other (Classify and include items in excess of \$50,000.)</td> </tr> <tr> <td> Fossil-fuel steam</td> <td>Total Cost Incurred</td> </tr> <tr> <td> Internal combustion or gas turbine</td> <td></td> </tr> <tr> <td> Nuclear</td> <td>Electric, R, D and D Performed Externally:</td> </tr> <tr> <td> Unconventional generation</td> <td>Research Support to the electrical Research Council or the Electric Power Research Institute</td> </tr> <tr> <td> Siting and heat rejection</td> <td>Research Support to Edison Electric Institute</td> </tr> <tr> <td> Transmission</td> <td>Research Support to Nuclear Power Groups</td> </tr> <tr> <td></td> <td>Research Support to Others (Classify)</td> </tr> <tr> <td></td> <td>Total Cost Incurred</td> </tr> </table> 3. 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. 4. 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). 5. 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. 6. 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."" 7. Report separately research and related testing facilities operated by the respondent.				Electric R, D and D Performed Internally:	Overhead Underground	Generation	Distribution	hydroelectric	Regional Transmission and Market Operation	Recreation fish and wildlife	Environment (other than equipment)	Other hydroelectric	Other (Classify and include items in excess of \$50,000.)	Fossil-fuel steam	Total Cost Incurred	Internal combustion or gas turbine		Nuclear	Electric, R, D and D Performed Externally:	Unconventional generation	Research Support to the electrical Research Council or the Electric Power Research Institute	Siting and heat rejection	Research Support to Edison Electric Institute	Transmission	Research Support to Nuclear Power Groups		Research Support to Others (Classify)		Total Cost Incurred
Electric R, D and D Performed Internally:	Overhead Underground																												
Generation	Distribution																												
hydroelectric	Regional Transmission and Market Operation																												
Recreation fish and wildlife	Environment (other than equipment)																												
Other hydroelectric	Other (Classify and include items in excess of \$50,000.)																												
Fossil-fuel steam	Total Cost Incurred																												
Internal combustion or gas turbine																													
Nuclear	Electric, R, D and D Performed Externally:																												
Unconventional generation	Research Support to the electrical Research Council or the Electric Power Research Institute																												
Siting and heat rejection	Research Support to Edison Electric Institute																												
Transmission	Research Support to Nuclear Power Groups																												
	Research Support to Others (Classify)																												
	Total Cost Incurred																												
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	10		930.2	10																							
4	Other	Miscellaneous																											
5	PERFORMED EXTERNALLY:																												
6		CHARLES RIVER ASSOCIATES		78,547	930.2	78,547																							
7		CHARTWELL INC		16,598	930.2	16,598																							

8	TOTAL:		10	95,145		95,155	

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	7,666,161			
4	Transmission	4,781,738			
5	Regional Market	842,990			
6	Distribution	6,088,992			
7	Customer Accounts	5,434,586			
8	Customer Service and Informational	1,545,828			
9	Sales	260,890			
10	Administrative and General	33,308,766			
11	TOTAL Operation (Enter Total of lines 3 thru 10)	59,929,951			
12	Maintenance				
13	Production	4,984,644			
14	Transmission	2,229,938			
15	Regional Market	14,636			
16	Distribution	6,252,295			
17	Administrative and General	1,798,383			
18	TOTAL Maintenance (Total of lines 13 thru 17)	15,279,896			
19	Total Operation and Maintenance				
20	Production (Enter Total of lines 3 and 13)	12,650,805			
21	Transmission (Enter Total of lines 4 and 14)	7,011,676			
22	Regional Market (Enter Total of Lines 5 and 15)	857,626			
23	Distribution (Enter Total of lines 6 and 16)	12,341,287			
24	Customer Accounts (Transcribe from line 7)	5,434,586			
25	Customer Service and Informational (Transcribe from line 8)	1,545,828			

26	Sales (Transcribe from line 9)	260,890		
27	Administrative and General (Enter Total of lines 10 and 17)	35,107,149		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	75,209,847		75,209,847
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			
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 Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57				

58	Distribution (Lines 36 and 48) 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)	75,209,847		75,209,847
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	26,428,372		26,428,372
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	26,428,372		26,428,372
72	Plant Removal (By Utility Departments)			
73	Electric Plant	25,925		25,925
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	25,925		25,925
77	Other Accounts (Specify, provide details in footnote):			
78	a Other Accounts (Specify, provide details in footnote):			
79	Fuel Stock (151)			
80	Miscellaneous Deferred Debits (186)	1,231,876		1,231,876
81	Expenses of Nonutility Operations (417.1)	51,005		51,005
82	Exp. for Certain Civic, Political and Related Activity (426.4)	164,614		164,614
83	Other Deductions (426.5)	218,815		218,815
84	Other Electric Revenue (456)	83,830		83,830
85				
86				
87				
88				
89				

90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,750,140		1,750,140
96	TOTAL SALARIES AND WAGES	103,414,284		103,414,284

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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.

FERC FORM NO. 1 (ED. 12-88)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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			

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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)	26,993,359	43,929,689	64,221,535	92,018,447
10	Net Sales (Account 447)	(3,308,361)	(4,912,702)	(7,942,291)	(10,667,529)
11	Transmission Rights (555)	(10,675,004)	(21,641,786)	(33,436,602)	(46,970,194)
12	Transmission Rights (447)				
13	Ancillary Services (555)	(212,888)	(507,887)	(1,150,975)	(1,352,773)
14	Ancillary Services (447)				
15	Other Items (list separately) (555)	(250,192)	(115,092)	161,157	622,287
16	Other Items (list separately) (447)	(115,817)	(150,058)	(227,133)	(271,576)
17	SPP				
18	Net Purchases (Account 555)	349,750	152,229	(135,218)	29,639
19	Net Sales (Account 447)				
20	Transmission Rights (555)		(267,888)	(267,888)	(267,888)
21	Ancillary Services (555)		151	190	204
22	Other Items (list separately) (555)	(719,954)	(719,230)	(719,141)	(718,933)
46	TOTAL	12,060,893	15,767,426	20,503,634	32,421,684

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4		
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. - On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year. - 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. - On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year. - On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year. - 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. - 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.							
		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	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			144,064	3,179,590	\$/MW-Hr	523,043
2	Reactive Supply and Voltage				0	0	
3	Regulation and Frequency Response				0	0	
4	Energy Imbalance				0	0	
5	Operating Reserve - Spinning				0	0	
6	Operating Reserve - Supplement				0	0	
7	Other				0	0	
8	Total (Lines 1 thru 7)			144,064	3,179,590		523,043

Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q4				
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	963	19	9	962	1				
2	February	889	28	9	888	1				
3	March	855	6	9	854	1				
4	Total for Quarter 1				2,704	3				
5	April	782	1	11	781	1				
6	May	685	24	10	684	1				
7	June	789	24	15	788	1				
8	Total for Quarter 2				2,253	3				
9	July	801	29	16	800	1				
10	August	808	2	16	807	1				
11	September	777	17	16	776	1				
12	Total for Quarter 3				2,383	3				
13	October	775	31	11	774	1				
14	November	847	29	23	846	1				
15	December	970	12	9	969	1				
16	Total for Quarter 4				2,589	3				
17	Total				9,929	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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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.

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024		Year/Period of Report End of: 2024/ Q4				
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) ☒ An Original (2) ☐ A Resubmission		Date of Report: 2024-12-31	Year/Period of Report End of: 2024/ Q4
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)	5,681,268
3	Steam	1,633,106	23	Requirements Sales for Resale (See instruction 4, page 311.)	2,570
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	298,649
5	Hydro-Conventional	9,591	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	(334)
7	Other	1,647,733	27	Total Energy Losses	63,393
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	3,290,430	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	6,045,546
10	Purchases (other than for Energy Storage)	3,012,593			
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	(28,632)			
17	Delivered	228,845			
18	Net Transmission for Other (Line 16 minus line 17)	(257,477)			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	6,045,546			

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 2024-12-31	Year/Period of Report End of: 2024/ Q4
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.

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4	
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	688,892	37,326	963	19	9
30	February	559,433	32,520	889	28	9
31	March	486,312	21,376	855	6	9
32	April	470,012	23,625	782	1	11
33	May	443,888	26,174	685	24	10
34	June	433,969	11,232	789	24	15
35	July	504,128	37,563	801	29	16
36	August	445,538	25,481	808	2	16
37	September	390,980	16,348	777	17	16
38	October	449,163	9,621	775	31	11
39	November	502,719	15,314	847	29	23
40	December	670,512	42,069	970	12	9
41	Total	6,045,546	298,649			

FERC FORM NO. 1 (ED. 12-90)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4					
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: ^(a) Big Stone	Plant Name: ^(b) 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)		278	257	150	36	15	47
7	Plant Hours Connected to Load		1,890	7,505	7,610	36	23	3,149
8	Net Continuous Plant Capability (Megawatts)		289	265	151	54	24	50
9	When Not Limited by Condenser Water		289	265	151	54	24	50
10	When Limited by Condenser Water		289	265	151	54	24	50
11	Average Number of Employees		4	77	80	0	0	2
12			413,198,990	863,725,645	769,380,104	194,005	85,999	124,681,576

	Net Generation, Exclusive of Plant Use - kWh									
13	Cost of Plant: Land and Land Rights			380,568	713,587	24,614	12,339	89,809		
14	Structures and Improvements		25,457,611	81,982,379	35,060,190	311,512	279,726	4,907,301		
15	Equipment Costs		122,836,889	259,667,001	147,510,965	7,705,595	4,121,526	25,870,045		
16	Asset Retirement Costs		1,072,896	3,959,941	4,781,324		0			
17	Total cost (total 13 thru 20)		149,367,396	345,989,889	188,066,066	8,041,721	4,413,591	30,867,155		
18	Cost per KW of Installed Capacity (line 17/5) Including		610	1,552	1,297	168	184	686		
19	Production Expenses: Oper, Supv, & Engr		59	596,974	830,992		10,556	1,450		
20	Fuel		11,632,054	23,136,301	22,788,643	138,843	55,088	3,155,261		
21	Coolants and Water (Nuclear Plants Only)						0			
22	Steam Expenses			2,356,329	3,230,636		0			
23	Steam From Other Sources						0			
24	Steam Transferred (Cr)						0			
25	Electric Expenses		78,518	899,960	766,420	6,009	5,777	159,299		
26	Misc Steam (or Nuclear) Power Expenses		180,164	2,246,875	1,009,825	12,646	50	430,294		
27	Rents		573		22,288		0	451		
28	Allowances						0			
29	Maintenance Supervision and Engineering		18,931	302,308	225,395	1,500	0	13,755		
30	Maintenance of Structures		29,704	477,015	387,764	6,087	4,458	27,528		
31	Maintenance of Boiler (or reactor) Plant			3,617,058	2,163,335		0			
32	Maintenance of Electric Plant		834,660	341,972	158,705	103,736	33,035	596,050		
33	Maintenance of Misc Steam (or Nuclear) Plant		112,920	372,783	739,695	14	1,720	902		
34	Total Production Expenses	0	12,887,583	34,347,575	32,323,698	268,835	110,684	4,384,990		
35	Expenses per Net kWh	0.0000	0.0312	0.0398	0.0420	1.3857	1.2870	0.0352		
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	4,298,600	602,836	3,132	670,031	3,501	1,177	689	1,235,546	53
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,091	8,206	140,000	6,962	140,000	140,000	140,000	1,046	140,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.710	38.171	108.230	33.116	105.420	109.200	114.240	2.550	0.000
41	Average Cost of Fuel per Unit Burned	2.710	38.027	121.000	33.123	127.260	118.125	100.670	2.550	106.218
42	Average Cost of Fuel Burned per Million BTU	2.710	2.317	20.578	2.379	21.643	20.089	17.121	2.550	18.064
43	Average Cost of Fuel Burned per kWh Net Gen	0.028	0.027	0.000	0.030	0.000	0.716	0.641	0.025	
44	Average BTU per kWh Net Generation	10,403.000	11,772.000	0.000	12,193.000	0.000	35,673.000	47,109.000	9,912.000	

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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
(c) Concept: FuelBurnedAverageHeatContent
Average Heat Content is in BTU/cf
(d) Concept: FuelBurnedAverageHeatContent
Average heat content is reported in BTU/lb for coal and BTU/gal for oil
(e) Concept: FuelBurnedAverageHeatContent
Average heat content is reported in BTU/lb for coal and BTU/gal for oil
(f) Concept: FuelBurnedAverageHeatContent
Average Heat Content is in BTU/gal for oil
(g) Concept: FuelBurnedAverageHeatContent
Average Heat Content is in BTU/gal for oil
(h) Concept: FuelBurnedAverageHeatContent
Average Heat Content is reported in BTU/cf for natural gas and BTU/gal for oil

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 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 project, in a 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 instructions.
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. If 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	
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)
1	Hydro:									
2	Dayton Hollow Hydro	1909	0.97	0.50	2,678	2,856,591	5,713,181	5,025		57,419
3	Hoot Lake Hydro	1914	0.67	0.70	3,289	3,544,379	5,063,398	21,433		73,927
4	Pisgah Hydro	1917	0.65	0.60	2,400	2,533,304	4,222,173	7,654		79,814
5	Wright Hydro	1922	0.40	0.00	(58)	1,860,735		4,471		30,802
6	Taplin Gorge Hydro	1925	0.56	0.50	1,282	1,060,477	2,120,953	10,171		61,170
7	Wind Turbine Plants:									
8	Langdon	2007	40.50	42.10	94,875	128,467,957	3,051,495	1,060,848		7,654
9	Ashtabula	2008	48.00	47.50	116,065	118,115,145	2,486,635	1,520,565		127,667
10	Luverne	2009	49.50	51.60	110,090	76,697,206	1,486,380	1,407,875		14,554
11	Ashtabula III	2010	62.40	54.80	142,585	83,637,930	1,526,240	2,084,054		157,542
12	Merricourt	2020	150.00	147.50	573,477	268,060,837	1,817,362	1,434,892		3,887,746
13	Solar Plants:									
14	Hoot Lake Solar	2023	49.90	50.20	72,335	62,957,310	1,254,130	116,486		468,934
15	Blue Jay Solar	2020	0.03	0.03	54	168,580	5,619,344			35,000
16	Blue Heron Solar	2020	0.03	0.03	89	156,123	5,204,086	3,262		31,000
17	Hoot Lake Solar Demonstration	2024	0.03	0.03	41	216,888	7,229,602			
18	Appleton ASB Solar	2024	0.04	0.03	4	133,329	4,444,311			

19	Beaver Solar	2024	0.04	0.03	8	116,921	3,897,365			
20	Brooks Solar	2024	0.04	0.03	3	121,302	4,043,408			
21	Callaway Solar	2024	0.04	0.03	3	123,950	4,131,681			
22	Crookston ASB Solar	2024	0.04	0.03	6	111,570	3,719,005			
23	Dalton Solar	2024	0.04	0.03	5	117,189	3,906,301			
24	Edgetown Solar	2024	0.04	0.03	3	115,090	3,836,317			
25	Karlstad ASB Solar	2024	0.04	0.03	2	111,298	3,709,932			
26	Brunswick Solar	2024	0.04	0.03	2	140,584	4,686,127			
27	NW Tech Solar	2024	0.04	0.03	4	112,876	3,762,517			
28	Red Lake Falls Solar	2024	0.04	0.03	0	118,452	3,948,396			
29	Sanford Solar	2024	0.04	0.03	3	124,621	4,154,025			
30	Taplin Gorge Solar	2024	0.04	0.03	3	122,083	4,069,418			
31	Viking Solar	2024	0.04	0.03	2	125,495	4,183,167			
32	Wall Lake Solar	2024	0.04	0.03	5	112,342	3,744,744			

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS

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 of the project.
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 (e) should be the sum of the amounts reported in columns (f) and (g).
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 energy storage project.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. Report the cost of power purchased 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 improvement costs, and any other costs associated with the energy storage project including but not exclusive of the cost of the energy storage project.

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)	M
1	Not Applicable			0						
35	TOTAL			0	0	0	0	0	0	

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4						
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

FERC FORM NO. 1 (NEW 12-12)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage c 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 volta
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do r
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; (; of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmis 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 o 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 col 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 fo transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another cc any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent o arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sha 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 h
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	COST Land, L
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1										
2	Center	Maple River	345	345	Alum Tower	47.73		1		
3	Alexandria	MN Border	345	345	Steel Tower	0.00		1		2,908,4
4	Big Stone South	Brookings	345	345	Steel Tower	71.59		1		3,602,8
5	Big Stone South	Ellendale	345	345	Steel Tower	161.88		1		547,8
6	Brookings	MN Border	345	345	Steel Tower	10.30		1		93,0
7	Cedar Mountain	Helena	345	345	Steel Tower	73.10		2		1,365,9
8	Cedar Mountain	Lyon County	345	345	Steel Tower	49.50		2		483,0
9	Chub Lake	Hampton	345	345	Steel Tower	18.15		1		491,5
10	Chub Lake	Helena	345	345	Steel Tower	20.92		1		869,8
11	Hazel Creek	Lyon County	345	345	Steel Tower	24.55		1		156,2
12			345	345	Steel Tower	48.35		1		129,3

	Lyon County	MN Border								
13	MN Border	Bison	345	345	Steel Tower	34.53		1		616,12
14	Monticello	Quarry Sub	345	345	Steel Tower	28.82		1		2,259,13
15	St. Cloud	Alexandria	345	345	Steel Tower	77.53		1		2,680,03
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		366,07
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		489,73
31	Cass Lake	Boswell	230	230	Steel H	51.19		1		567,06
32	Hazel Creek	MN Valley	230	345	Steel Tower	5.00		1		47,53
33	Big Stone Plant	Big Stone South	230	230	Steel Tower	1.58		1		53,87
34	Big Stone Plant	Big Stone South	230	230	Steel Tower	1.71		1		58,23
35		Total	115	115	Wood H	494.36				1,112,03
36		Total	115	115	SWP	483.53				2,672,17
37		Total	115	115	Steel Tower	4.29				15,54
38		Total	69	69		219.85				53,44
39		Total	41.6	41.6	SWP	3,778.36				
40		Total	41.6	41.6	Underground	1.00				
36	TOTAL					6,132	0	35		21,638,86

FERC FORM NO. 1 (ED. 12-87)

Page 422-423

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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.

FERC FORM NO. 1 (ED. 12-87)

Page 422-423

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 repairs.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of construction are reported in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way in column (m). 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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			V (kV)
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Michigan	Mapes	6.30	41.6 kV	20	3	1	1/0T2	ACSR	3102 - 4'	
2	Michigan	Mapes	(6.30)	Retire	20	3	1	5 mile 266 ACSR /1.3 Miles 1/0 Copper	Various	3050 - 4'	
3	Granville	Towner	(8.00)	Retire	20	3	1	3/0R	ACSR	3050 - 4'	
4	Alice, ND Substation	S 0.5 miles south of Alice, ND Sub	1	Single Pole	20	1	1	1/0RT2	ACSR	3651P	
5	Alice, ND Substation	S 0.5 miles south of Alice, ND Sub	(1)	Retire	20	1	1	266R	ACSR	3612	
6	Hoot Lake Sub	SE 0.25 miles of Hoot Lake Sub	0	Single Pole	20	2	2	266R / 3/0R	ACSR	3102D	
7	Hoot Lake Sub	SE 0.25 miles of Hoot Lake Sub	0	Retire	20	2	2	266R / 3/0R	ACSR	3345	
8	Milbank NW Sub (Existing 1 of 4)	Big Stone Plant Sub (Existing)	12.87	3651P (Most common)	20	1	1	2 x 477 18/1 Pelican ACSR-T2	Twisted Pair	Vertical Construction	
9	Milbank NW Sub (Existing 2 of 4)	Big Stone Plant Sub (Existing)	12.87	3651P (Most common)	20	1	1	2 x 266.8 18/1 Waxwing ACSR-T2	Twisted Pair	Vertical Construction	
10	Milbank NW Sub (Existing 3 of 4)	Big Stone Plant Sub (Existing)	12.87	3651P (Most common)	20	1	1	477 18/1 Pelican ACSR	Single Conductor	Vertical Construction	

11	Milbank NW Sub (Existing 4 of 4)	Big Stone Plant Sub (Existing)	12.87	3651P (Most common)	20	1	1	795 26/7 Drake ACSS	Single Conductor	Vertical Construction
12	Page, ND	E 1.8 miles of Page, ND	2	Single Pole	19	1	1	1/0R	ACSR	3102
13	Page, ND	E 1.8 miles of Page, ND	(2)	Retire						
14	Lyon County	MN Border	11	Single Pole	6	1	2	2X397.5-26/7	ZTACSR twisted pair conductor	Vertical Construction
15	Brookings	MN Border	60	Singe Pole	6	1	2	2X397.5-26/7	ZTACSR twisted pair conductor	Vertical Construction
44	TOTAL		114		251	22	18			

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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.
(f) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(g) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(h) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(i) Concept: CostOfTransmissionLinesAdded
Estimated total cost are second circuit, ownership 4.8%.
(j) Concept: CostOfTransmissionLinesAdded
Estimated total cost are second circuit, ownership 4.8%.

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

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 function be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or 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 increase.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of special equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts 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)
		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	Unattended	345.00	115.00	43.00	112.00	
2	Ashtabula III Substation - 657745	Transmission	Unattended	242.00	35.00		75.00	
3	Bemidji, MN - 115 kv - 620246	Transmission	Unattended	115.00	69.00	14.00	15.00	
4	a Big Stone, SD - 230 kv - 620314	Transmission	Unattended	236.00	118.00	14.00	233.00	
5	Big Stone, SD Highway 12 - 115 kv - 620215	Transmission	Unattended	115.00	44.00	0.00	44.80	
6	Big Stone South, SD - 345 kv - 620417	Transmission	Unattended	345.00	230.00	35.00	896.00	
7	Bottineau, ND - 115 kv - 620183	Transmission	Unattended	115.00	42.00		36.00	
8	Browns Valley, MN - 230 kv (Peever) - 620325	Transmission	Unattended	230.00	44.00		26.88	
9	Buffalo, ND - 345 kv - 620358	Transmission	Unattended	345.00	115.00	42.00	200.00	
10	Canby, MN - 115 kv - 620211	Transmission	Unattended	115.00	44.00		20.00	
11	Cass Lake, MN - 115 kv - 620247	Transmission	Unattended	115.00	69.00	42.00	55.00	
12	Cass Lake, MN - 230 kv - 620447	Transmission	Unattended	230.00	118.00	14.00	187.00	
13	Clearbrook, MN - 115 kv - 620241	Transmission	Unattended	115.00	42.00		10.00	
14	Crookston, MN - 115 kv - 620249	Transmission	Unattended	115.00	42.00		51.00	
15	Devils Lake, ND - East 115 kv - 620265	Transmission	Unattended	115.00	44.00		33.60	
16	Devils Lake, ND - SW 115 kv - 650268	Transmission	Unattended	115.00	44.00		30.00	
17	Donaldson, MN - 115 kv - 620255	Transmission	Unattended	115.00	42.00		20.00	
18	Erie, MN 230 kv - 620326	Transmission	Unattended	236.00	118.00	2.00	187.00	

19	Fergus Falls, MN - Hoot Lake 115 kv - 620223	Transmission	Unattended	115.00	44.00	35.00	80.00	
20	Fertile, MN - 115 kv - 620250	Transmission	Unattended	115.00	42.00		10.00	
21	Pickert 115 kv - 620188	Transmission	Unattended	230.00	72.00	41.60	60.00	
22	Forman, ND - Forman 230 kv - 620363	Transmission	Unattended	230.00	118.00	34.00	140.00	
23	Forman, ND 2 - Forman 230 kv - 620363	Transmission	Unattended	230.00	115.00	13.00	187.00	
24	Hensel, ND - 115 kv - 620157	Transmission	Unattended	115.00	72.00	44.00	33.00	
25	Hetland, SD - 115 kv - 620209	Transmission	Unattended	115.00	44.00		44.80	
26	Jamestown, ND - 345 kv - 620369	Transmission	Unattended	345.00	115.00	44.00	672.00	
27	Jamestown, ND - Peaking Plant 115 kv - 620272	Transmission	Unattended	115.00	43.00		60.00	
28	Luverne 230 kV Sub - 657702	Transmission	Unattended	230.00	34.00	13.00	225.00	
29	Maple River, ND - 345 kv - 620359	Transmission	Unattended	345.00	230.00	14.00	672.00	
30	Mapleton, ND - 115 kv - 620203	Transmission	Unattended	115.00	43.00		29.00	
31	Marietta, MN - 115 kv - 620213	Transmission	Unattended	115.00	42.00		10.00	
32	Merricourt, ND - 230 kv - 661992	Transmission	Unattended	230.00	35.00	14.00	167.00	
33	Milbank NW	Transmission	Unattended	115.00	13.00		56.00	
34	New Effington, SD - 620328	Transmission	Unattended	236.00	43.00		33.60	
35	Norcross 115kV Sub - 620370	Transmission	Unattended	115.00	44.00		44.80	
36	Northwoods, MN - 115kv - 620282	Transmission	Unattended	115.00	44.00		12.00	
37	Oakes, ND - 230 kv - 620362	Transmission	Unattended	230.00	43.00		67.20	
38	Ortonville, MN - 115 kv - 620216	Transmission	Unattended	115.00	44.00		29.90	
39	Pelican Rapids, MN - 115 k - 620234	Transmission	Unattended	115.00	42.00		10.00	
40	Plummer, MN - 115kv - 650252	Transmission	Unattended	115.00	44.00		18.00	
41	Rugby, ND - 230 kv - 620379	Transmission	Unattended	230.00	115.00	42.00	140.00	
42	Rugby, ND 2 - 230 kv - 620379	Transmission	Unattended	230.00	115.00	14.00	75.00	
43	Solway 115 kV Sub - 620285	Transmission	Unattended	115.00	14.00		48.00	
44	Spiritwood, ND - 620270	Transmission	Unattended	115.00	42.00		16.00	
45	Toronto, SD - 115 kv - 620210	Transmission	Unattended	115.00	13.00		46.00	
46	Toronto, SD 2 - 115 kv - 620210	Transmission	Unattended	115.00	42.00		45.00	
47	Wahpeton Inventory	Transmission	Unattended	115.00	44.00			
48	Wahpeton, ND - 230 kv - 620329	Transmission	Unattended	230.00	115.00	43.00	280.00	
49	WAPA Summit, SD	Transmission	Unattended	115.00	42.00		25.00	
50	Winger, MN 63238	Transmission	Unattended	230.00	115.00	13.00	327.00	
51	Transmission Subs Under 10,000 kva		Unattended					
52	Colgate	Transmission	Unattended	69.00	44.00	13.00	6.10	

53	Green Valley	Transmission	Unattended	67.00	42.00		10.00	
54	Lake Preston East River	Transmission	Unattended	69.00	44.00		8.00	
55	Mountrail-Parshall - 8129	Transmission	Unattended	44.00	25.00	2.00	12.50	
56	Wahpeton Inventory 2	Transmission	Unattended	69.00	42.00			
57	Bemidji, MN 25th Street	Distribution	Unattended	69.00	13.00		15.00	
58	Bemidji, MN Airport	Distribution	Unattended	44.00	13.00		10.00	
59	Bemidji, MN Nymore	Distribution	Unattended	69.00	13.00		10.00	
60	Bemidji, MN Industrial Park	Distribution	Unattended	69.00	13.00		7.50	
61	Bottineau, ND Downtown	Distribution	Unattended	42.00	13.00		10.00	
62	Bottineau, ND South	Distribution	Unattended	44.00	13.00		10.00	
63	Casselton, ND	Distribution	Unattended	44.00	8.00		10.00	
64	Casselton, ND 115 Ethanol plant	Distribution	Unattended	115.00	13.00		66.00	
65	Cass Lake, MN 620348	Distribution	Unattended	115.00	13.00		10.00	
66	Cass Lake N Sub - 7919	Distribution	Unattended	115.00	13.00		10.00	
67	Clearbrook, MN Pipeline	Distribution	Unattended	115.00	4.00		20.00	
68	Cooperstown, ND	Distribution	Unattended	44.00	13.00		10.00	
69	Crookston, MN Parkview	Distribution	Unattended	44.00	13.00		10.00	
70	Crookston, MN South Main	Distribution	Unattended	42.00	13.00		25.00	
71	Dawson, Mn Dawson Mills	Distribution	Unattended	115.00	13.00		10.00	
72	Devils Lake, ND Downtown	Distribution	Unattended	44.00	4.00		10.00	
73	Enderlin, ND	Distribution	Unattended	115.00	13.00		14.00	
74	Fergus Falls, MN Edgetown	Distribution	Unattended	115.00	13.00		20.00	
75	Fergus Falls, MN Hoot Lake	Distribution	Unattended	115.00	14.00		7.50	
76	Fergus Falls, MN South East	Distribution	Unattended	115.00	13.00		37.30	
77	Gwinner, ND	Distribution	Unattended	115.00	13.00		20.00	
78	Harvey, ND Northwest	Distribution	Unattended	115.00	13.00		14.00	
79	Itasca, MN Minnesota Pipeline	Distribution	Unattended	115.00	4.00		10.00	
80	Jamestown, ND Downtown	Distribution	Unattended	115.00	13.00		54.80	
81	Jamestown, ND North	Distribution	Unattended	115.00	13.00		10.00	
82	Jamestown, ND Potato	Distribution	Unattended	115.00	13.00		10.00	
83	Jamestown, ND Southwest	Distribution	Unattended	44.00	13.00		10.00	
84	Lake Norden, SD	Distribution	Unattended	115.00	13.00		93.30	
85	Lisbon, ND Town	Distribution	Unattended	115.00	12.00		14.00	
86	Mahnomen, MN	Distribution	Unattended	115.00	13.00		10.00	
87	Milbank, SD Northwest	Distribution	Unattended	115.00	13.00		56.00	
88	Milbank, SD South	Distribution	Unattended	44.00	13.00		22.40	
89	Parkers Prairie	Distribution	Unattended	44.00	13.00		12.50	

90	Pelican Rapids, MN Turkey Plant	Distribution	Unattended	115.00	13.00		12.50	
91	Perham, MN	Distribution	Unattended	115.00	13.00		13.00	
92	Rosholt, SD	Distribution	Unattended	44.00	13.00		11.20	
93	Rugby, ND Northwest	Distribution	Unattended	44.00	13.00		14.00	
94	Spiritwood, ND	Distribution	Unattended	115.00	13.00		14.00	
95	Wahpeton Inventory 3	Distribution	Unattended	115.00	13.00			
96	Wahpeton Inventory 4	Distribution	Unattended	115.00	4.00			
97	Wahpeton Inventory 5	Distribution	Unattended	42.00	4.00			
98	Wahpeton Inventory 6	Distribution	Unattended	42.00	13.00			
99	Wahpeton, ND North 115 kv - 620230	Distribution	Unattended	115.00	13.00		24.00	
100	Wahpeton, ND Northwest	Distribution	Unattended	42.00	13.00		22.40	
101	Wheaton, MN South	Distribution	Unattended	115.00	13.00		14.00	
102	Distribution Substations under 10,000 kva	Distribution	Unattended				1316	11
103	TotalDistributionSubstationMember						2,100	1,1
104	TotalTransmissionSubstationMember						5,932	
105	Total						8,032	1,2

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ 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.

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Name of Respondent: Otter Tail Power Company		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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	3,857	
3	Expenditures for certain civic, political & relat	Otter Tail Corporation	426.4	15,750	
4	Dividends declared - common stock	Otter Tail Corporation	438	62,553,005	
5	^(a) Corporate allocated A&G expense	Otter Tail Corporation	^(b) See Note	14,866,422	
19					
20	Non-power Goods or Services Provided for Affiliated				
21	Printing, design & mailing services	Otter Tail Corporation	417	22,874	
22	Other deductions	Otter Tail Corporation	426.5	321,848	
23	Printing, design & mailing services	TO Plastics	417	76	
24	Printing, design & mailing services	BTD Manufacturing	417	9,168	
25	Printing, design & mailing services	Northern Pipe Products	417	100	
26	Printing, design & mailing services	Vinyltech Corporation	417	64	
42					

Name of Respondent: Otter Tail Power Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

The following accounts were charged:

Account	Amount (\$)
500.0	7,334
549.0	811
506.0	54,048
908.0	2,348
920.0	5,709,926
921.0	5,786,402
923.0	1,968,963
924.0	101,392
925.0	209,890
926.0	90,836
928.0	23,303
930.1	26,458
930.2	598,442
931.0	123,047
935.0	163,222
	14,866,422

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