GROW
OUR BUSINESSES

ACHIEVE
OPERATIONAL EXCELLENCE

DEVELOP
OUR TALENT

OTTER TAIL CORPORATION

2016

ESSENTIAL LEADERSHIP

2016 ANNUAL REPORT

ANNUAL REPORT

Otter Tail Corporation Senior Internal Auditor **Melissa Anderson** (right) provides insight to enhance processes that improve risk management and strengthen internal controls.

Otter Tail Power Company Senior Project Engineer **Lynn Hardy** (left) and Aerial Basket Crew Foreman **Royce Shoemaker** are working on the new two-mile, 230-kilovolt transmission line between the Big Stone Plant Substation and the new Big Stone South Substation. The new substation is the starting point of the Big Stone South-Brookings County and Big Stone South-Ellendale 345-kilovolt lines that are key components of our rate-base growth strategy.

VISION

WE WILL BUILD A STRONG AND FOCUSED DIVERSIFIED ORGANIZATION WITH AN ELECTRIC UTILITY AS OUR FOUNDATION.

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 an environment where people thrive.
PERFORMANCE: We strive for excellence, act on opportunity, and deliver on commitments.
COMMUNITY: We improve the communities where we work and live.

MISSION

Otter Tail Corporation delivers value by building strong electric utility and manufacturing platforms.

- For our shareholders we deliver above-average returns through 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 people are valued and empowered to do their best work.

SUMMARY OF THE YEAR

CONSOLIDATED OPERATIONS ($ in thousands, except share amounts)	2016	2015	PERCENT CHANGE
Operating Revenues	$ 803,539	$ 779,804	3.0
Net Income from Continuing Operations	$ 62,037	$ 58,589	5.9
Net Income	$ 62,321	$ 59,345	5.0
Diluted Earnings per Share from Continuing Operations	$ 1.60	$ 1.56	2.6
Diluted Earnings per Share	$ 1.61	$ 1.58	1.9
Dividends per Common Share	$ 1.25	$ 1.23	1.6
Return on Average Common Equity	9.8%	10.1%	(3.0)
Book Value per Common Share	$ 17.03	$ 15.98	6.6
Cash Flow from Continuing Operations	$ 163,541	$ 131,540	24.3
Number of Common Shares Outstanding	39,348,136	37,857,186	3.9
Number of Common Shareholders	13,805	14,062	(1.8)
Closing Stock Price	$ 40.80	$ 26.63	53.2
Total Return (share price appreciation plus dividends)	57.9%	(10.0)%	679.0
Total Market Value of Common Stock	$ 1,605,404	$ 1,008,137	59.2
Total Full-time Employees—Continuing Operations	2,054	2,005	2.4

ELECTRIC PLATFORM ($ in thousands)			
Operating Revenues:			
Retail	$ 376,610	$ 364,614	3.3
Wholesale—Net of Purchased Power Costs	4,584	2,685	70.7
Other	46,155	39,740	16.1
Total Electric Operating Revenues	$ 427,349	$ 407,039	5.0
Total Retail Electric Sales (MWH)	4,750,421	4,593,604	3.4
Operating Income	$ 90,131	$ 87,171	3.4
Customers	131,546	131,149	0.3
Gross Plant Investment	$ 2,010,354	$ 1,884,880	6.7
Total Assets	$ 1,622,231	$ 1,520,887	6.7
Capital Expenditures	$ 149,648	$ 135,572	10.4
Full-time Employees	682	651	4.8

MANUFACTURING PLATFORM (Continuing Operations, $ in thousands)			
Operating Revenues	$ 376,190	$ 372,765	0.9
Operating Income	$ 29,911	$ 31,358	(4.6)
Total Assets	$ 251,117	$ 255,484	(1.7)
Capital Expenditures	$ 11,514	$ 24,501	(53.0)
Full-time Employees	1,331	1,308	1.8

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DIRECTORS AND LEADERSHIP 99

TO OUR SHAREHOLDERS

CHARLES S. MACFARLANE
PRESIDENT AND CEO

Otter Tail Corporation continued its long-term commitment to stable, predictable performance in 2016. Our streamlined operation as a two-platform company delivered shareholder value through our high-performing, low-cost electric utility and disciplined manufacturing companies.

The foundation that underlies our ongoing success at Otter Tail Corporation is the essential leadership of our employees. All our employees are leaders, regardless of their position, company, or location. They take responsibility for their actions, generate ideas, raise concerns, and serve as examples to others. With more than 2,000 employees across six states, our people make our success.

Their ability to lead the business produced solid results. The corporation's net income and diluted earnings per share from continuing operations were $62.0 million and $1.60, respectively, compared with $58.6 million and $1.56 for 2015, despite significant financial challenges at the utility associated with weather. Return on equity was 9.8 percent.

Our stock performed well in 2016 compared with major utility and broad market indexes. Total return was 57.9 percent, and our year-end dividend yield is 3.1 percent. We have paid dividends on common stock for 78 years, or 313 consecutive quarters. Our annual indicated dividend rate per share for 2017 is $1.28.

We continue to execute on our strategic initiatives to grow the business, achieve operational excellence, and develop our talent, and we are confident that our long-term approach is effective. With the talents and skills of our employees, we are able to turn our strategy into action—to the shared benefit of our customers, shareholders, employees, and communities.

ELECTRIC PLATFORM PROVIDES ESSENTIAL GROWTH AND STABILITY

Otter Tail Power Company continued to execute its growth plan in 2016. The utility expects to invest $862 million from 2017 to 2021 in rate-base expansion, including regional transmission projects, renewable energy, and natural gas-fired generation, producing an expected compounded annual growth rate in rate base of 7.5 percent between 2015 and 2021. Most projects are eligible for cost recovery during construction.

Regional transmission projects are key components of our rate-base expansion. Otter Tail Power Company is a 50 percent owner in two 345-kilovolt transmission lines. Neighboring utilities are co-owners. Both lines are designated multi-value projects within the Midcontinent Independent System Operator, Inc. (MISO) footprint, bringing improved reliability, increased system capacity, and support for public policy goals related to integrating renewable energy. The costs of these projects will be allocated across all customers in MISO's 12-state Upper Midwest footprint. The 70-mile line that runs south from the Big Stone South Substation to Brookings County, South Dakota, is on budget and expected to be energized in late 2017. The 163-mile line

WE ARE POISED FOR
LONG-TERM SUCCESS.
WE HAVE SHARPENED
OUR FOCUS AND ARE
STRENGTHENING OUR
POSITION IN THE MARKETS
WE SERVE.

that runs northwest from the Big Stone South Substation to Ellendale, North Dakota, began construction in 2016. It is on budget and expected to be completed in 2019. Otter Tail Power Company is managing the Big Stone South-Ellendale project. Our expected investment for both projects totals $229 million.

The utility's resource plan, filed with Minnesota in June, identifies the most cost-effective combination of resources for meeting customers' needs for reliable service over the next 15 years.

Otter Tail Power Company plans to retire its baseload coal-fired Hoot Lake Plant in 2021. The utility will add additional wind energy and natural gas-fired generation to replace energy and capacity from the plant. We already have announced the purchase of a 150-megawatt wind farm to be built in southeastern North Dakota in 2019. At an estimated cost of approximately $250 million, it will be the largest capital project in company history. With this addition, the amount of wind energy that supplies customers' electricity needs will jump from 19 percent to approximately 28 percent. Few utilities in the nation have a higher percentage of renewable wind energy.

The construction of a planned 250-megawatt simple-cycle natural gas-fired plant will replace both Hoot Lake Plant capacity and expiring long-term purchased power agreements. We expect the site of the natural gas combustion turbine will benefit from close proximity to a high-voltage transmission line and a major natural gas pipeline within Otter Tail Power Company's service area.

The utility's resource plan also includes adding 30 megawatts of solar resources by 2020 to comply with Minnesota's Solar Energy Standard. A resource plan ruling is expected in 2017.

The company filed a rate case with the Minnesota Public Utilities Commission in February requesting a 9.8 percent rate increase, or approximately $19.3 million annually. The proposed increase reflects the company's investments in new environmental technologies and a stronger transmission system that delivers electricity to its customers. The commission granted an interim rate increase of 9.56 percent in April and is expected to issue its final order in spring 2017, which may result in a reduced rate increase.

Otter Tail Power Company is committed to producing reliable, affordable electricity in an environmentally responsible manner. Even with a potential rate increase, it offers some of the lowest rates in the nation.

Underlying the company's operational excellence is the value the utility places on customer satisfaction and workplace safety. The company is a top performer in the American Customer Satisfaction Index study, with residential customers consistently scoring us as one of the highest ranked investor-owned utilities in the nation. We had a record year in energy-efficiency programs in 2016, saving customers 58 million kilowatt-hours—equal to the annual energy use of 5,000 homes. And we ended the year with a strong safety record, finishing with the company's lowest OSHA recordable incident rate ever. The utility will continue to deliver on these values as it looks toward future growth and success.

MANUFACTURING PLATFORM POSITIONS FOR GROWTH

We continue to position our manufacturing platform for sales growth and operational excellence.

Economic pressures in the agriculture, oil and gas, and recreational vehicle equipment end markets and a general weakness in United States manufacturing due to a stronger dollar and lower capital spending impacted BTD Manufacturing, our custom metal fabricator, again this year. Nevertheless, BTD nearly doubled earnings year over year, although we still are working to regain the earnings levels it achieved prior to 2015.

The company completed its facilities expansion in Detroit Lakes and Lakeville, Minnesota, which added in-house painting and complex assembly capabilities and reduced logistics costs. The Illinois facility experienced increased sales associated with the renewable wind energy industry. Integration of the Georgia plant acquired in late 2015 is progressing. While soft end markets negatively impacted Georgia's 2016 financial performance even more than other BTD locations, we remain committed to this Southeast expansion to better serve BTD's customers, who are some of the top original equipment manufacturers in the nation.

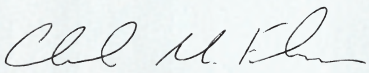
T.O. Plastics, our thermoforming manufacturer, remains focused on its primary market, horticulture containers, which accounts for 63 percent of total sales. The company also continues to build on its life science business while pursuing other custom solutions opportunities. The company's ongoing emphasis on workplace safety reached a milestone in 2016 with 324 days without a reportable OSHA incident.

Northern Pipe Products and Vinyltech, our PVC pipe manufacturers, faced challenges with a declining margin between sale prices and raw material prices. Strong year-over-year pipe volume growth of 10.5 percent offset some of the margin compression and allowed the companies to meet their financial targets. They concluded the year with a solid performance due to positive employee engagement, low operating and capital costs, and outstanding customer service.

WE ARE SETTING A COURSE FOR THE FUTURE

Otter Tail Corporation is poised for long-term success. We'll continue to execute on our strategic initiatives as we move into 2017. Focused on growing our businesses, achieving operational excellence, and developing talent, we are creating the future we desire.

We thank our employees for their dedication and accomplishments. They drive the corporation's successes. And we thank you, our shareholders, for placing your trust and confidence in us.



Charles S. MacFarlane
President and Chief Executive Officer

OTTER TAIL CORPORATION

ELECTRIC

OTTER TAIL POWER COMPANY
Electric utility | Fergus Falls, MN | 1907
Tim Rogelstad | 682 employees
www.otpco.com

MANUFACTURING

BTD MANUFACTURING, INC.
Metal fabricator | Detroit Lakes, MN | 1995
Paul Gintner | 1,037 employees | www.btdmfg.com

T.O. PLASTICS, INC.
Custom plastic parts manufacturer
Clearwater, MN | 2001
Mike Vallafskey | 138 employees | www.toplastics.com

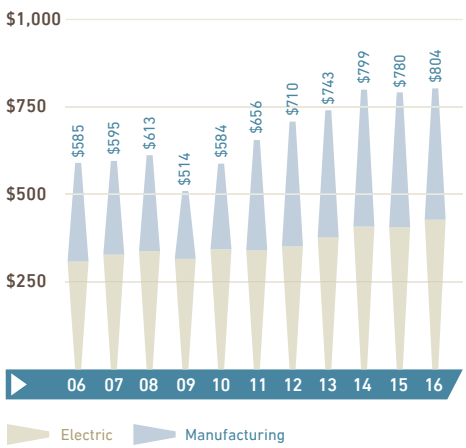
NORTHERN PIPE PRODUCTS, INC.
PVC pipe manufacturer | Fargo, ND | 1995
Steve Laskey | 90 employees | www.northernpipe.com

VINYLTECH CORPORATION
PVC pipe manufacturer | Phoenix, AZ | 2000
Steve Laskey | 66 employees | www.vtpipe.com

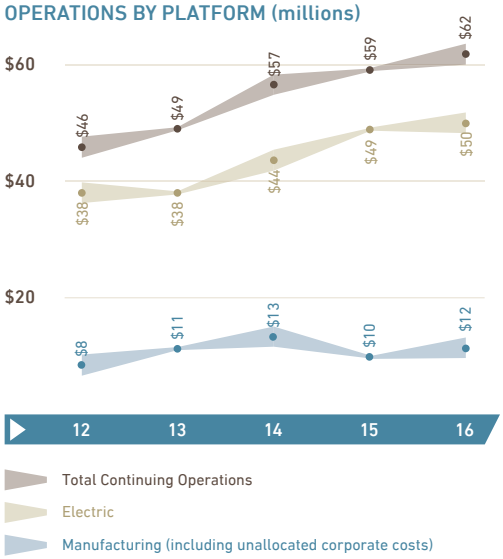
LEGEND

Company name
Company description
Headquarters
Year acquired
President
Full-time employees
Website

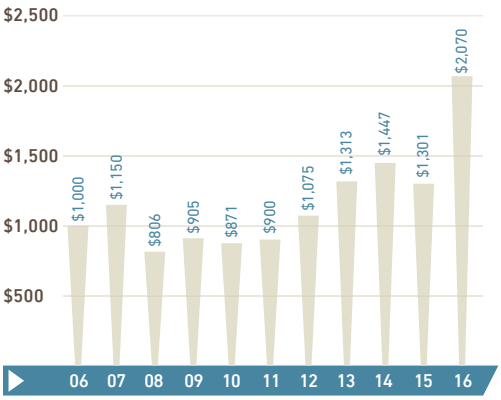
REVENUE BY PLATFORM (millions)



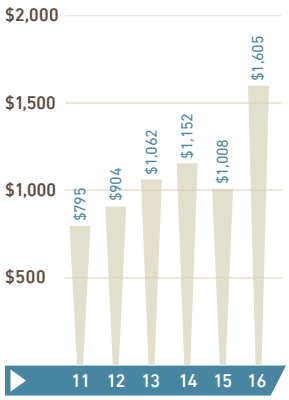
NET INCOME FROM CONTINUING OPERATIONS BY PLATFORM (millions)



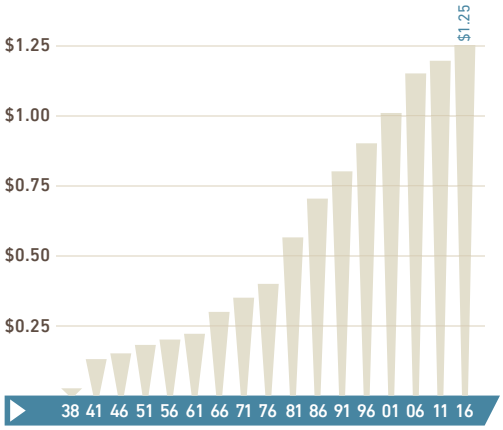
GROWTH OF $1,000 INVESTMENT IN OTTER TAIL COMMON STOCK MADE DECEMBER 31, 2006 (with dividends reinvested)



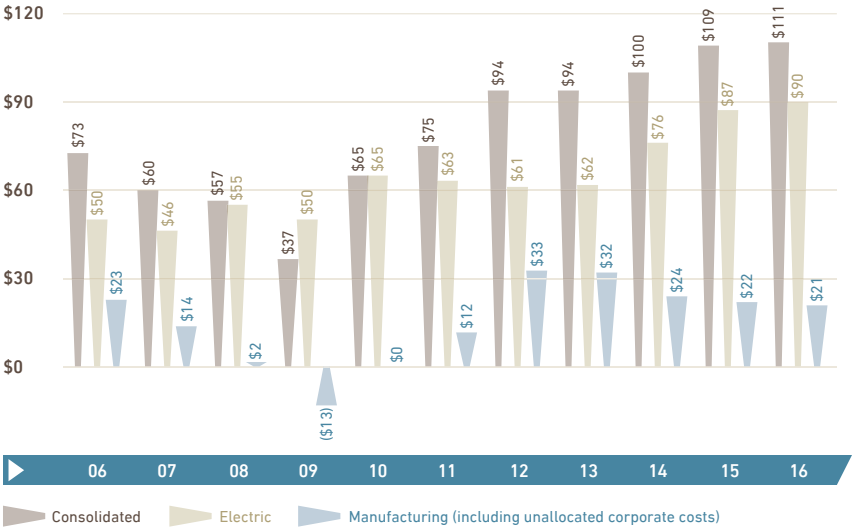
MARKET CAPITALIZATION (millions)



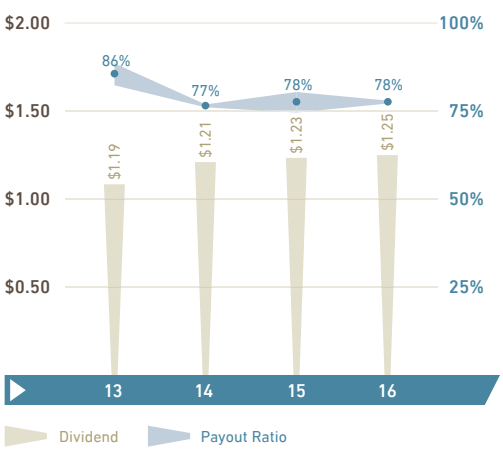
DIVIDEND PAYMENT HISTORY



OPERATING INCOME BY PLATFORM (millions, pre-tax)



DIVIDEND PAYOUT RATIO



SELECTED COMMON SHARE DATA	2016	2015	2014	2013	2012	2011
Market Price:						
High	$ 42.55	$ 33.44	$ 32.72	$ 31.88	$ 25.25	$ 23.48
Low	$ 25.80	$ 24.82	$ 26.53	$ 25.17	$ 20.70	$ 17.53
Common Price/Earnings Ratio:						
High	26.4	21.2	20.8	22.9	—	—
Low	16.0	15.7	16.9	18.1	—	—
Book Value per Common Share	$ 17.03	$ 15.98	$ 15.39	$ 14.75	$ 14.43	$ 15.83

SELECTED DATA AND RATIOS	2016	2015	2014	2013	2012	2011
Interest Coverage before Taxes (1)	3.5x	3.5x	3.4x	3.1x	2.6x	2.1x
Effective Income Tax Rate (percent) (2)	24	27	23	20	13	13
Return on Capitalization Including Short-term Debt (percent)	7.5	7.6	8.0	7.7	8.1	6.8
Return on Average Common Equity (percent) (3)	9.8	10.1	10.4	9.5	(1.1)	(2.3)
Dividend Payout Ratio (percent)	78	78	77	86	—	—
Capital Ratio (percent): (4)						
Short-term and Long-term Debt	46.5	48.8	47.0	45.1	43.8	44.3
Preferred Stock and Other Equity	—	—	—	—	1.6	1.5
Common Equity	53.5	51.2	53.0	54.9	54.6	54.2
	100.0	100.0	100.0	100.0	100.0	100.0

Notes: (1) Continuing Operations.
(2) Continuing Operations; see note 14 to consolidated financial statements in 2016 Annual Report on Form 10-K.
(3) Earnings available for common shares divided by the 13-month average of month-end common equity balances.
(4) 2011 through 2015 adjusted in 2016 to reflect the netting of unamortized debt expenses against related debt on the liability side of the balance sheet.

SELECTED ELECTRIC OPERATING DATA	2016	2015	2014	2013	2012	2011
Revenues (thousands)						
Residential	$ 115,782	$ 116,279	$ 119,730	$ 113,434	$ 104,145	$ 105,997
Commercial and Farms	135,813	128,406	138,126	125,965	115,299	116,491
Industrial	116,561	108,331	93,841	78,998	79,969	76,690
Sales for Resale	4,584	2,685	12,191	16,461	14,377	16,837
Other Electric	54,643	51,430	43,855	38,682	36,975	26,712
Total Electric	$ 427,383	$ 407,131	$ 407,743	$ 373,540	$ 350,765	$ 342,727
Kilowatt-hours Sold (thousands)						
Residential	1,220,946	1,272,912	1,386,104	1,378,859	1,253,567	1,315,798
Commercial and Farms	1,598,668	1,585,037	1,708,570	1,685,046	1,566,747	1,592,432
Industrial	1,866,726	1,668,958	1,531,684	1,357,026	1,355,876	1,315,051
Other	64,081	66,697	68,704	66,610	64,599	68,356
Total Retail	4,750,421	4,593,604	4,695,062	4,487,541	4,240,789	4,291,637
Sales for Resale	190,288	113,057	290,757	643,878	565,274	633,408
Total	4,940,709	4,706,661	4,985,819	5,131,419	4,806,063	4,925,045
Annual Retail Kilowatt-hour Sales Growth (percent)	3.4	(2.2)	4.6	5.8	(1.2)	0.7
Heating Degree Days (5)	5,314	5,633	7,205	7,344	5,356	6,217
Cooling Degree Days (6)	451	483	367	510	648	552
Average Revenue per Kilowatt-hour						
Residential	9.48¢	9.13¢	8.64¢	8.23¢	8.31¢	8.06¢
Commercial and Farms	8.50¢	8.11¢	8.08¢	7.48¢	7.36¢	7.32¢
Industrial	6.24¢	6.49¢	6.13¢	5.82¢	5.90¢	5.83¢
All Retail	7.82¢	7.83¢	7.63¢	7.23¢	7.20¢	7.02¢
Customers						
Residential	103,570	103,307	102,771	102,510	102,204	101,789
Commercial and Farms	26,919	26,777	26,672	26,629	26,522	26,427
Industrial	44	47	47	45	42	43
Other	1,013	1,018	1,000	1,004	1,018	1,000
Total Electric Customers	131,546	131,149	130,490	130,188	129,786	129,259
Residential Sales						
Average Kilowatt-hours per Customer (7)	11,895	12,460	13,714	13,488	12,293	13,191
Average Revenue per Residential Customer	$ 1,128.22	$ 1,175.08	$ 1,197.87	$ 1,116.22	$ 1,050.25	$ 1,070.65
Depreciation Reserve (thousands)						
Electric Plant in Service	$ 1,860,357	$ 1,820,763	$ 1,545,112	$ 1,460,884	$ 1,423,303	$ 1,372,534
Depreciation Reserve	$ 622,657	$ 592,001	$ 584,956	$ 554,818	$ 526,467	$ 499,327
Reserve to Electric Plant (percent)	33.5	32.5	37.9	38.0	37.0	36.4
Composite Depreciation Rate (percent)	2.88	2.61	2.89	2.96	2.98	2.94
Peak Demand and Net Generating Capability						
Peak Demand (kilowatts)	876,026	896,706	873,842	863,561	823,591	810,984
Net Generating Capability (kilowatts): (8)						
Steam	545,700	546,300	556,400	554,600	547,300	545,100
Wind	138,000	138,000	138,000	138,000	138,000	138,000
Combustion Turbines	108,100	108,500	107,800	104,900	108,000	108,000
Hydro	2,500	2,500	2,500	2,600	2,800	2,700
Total Owned Generating Capability	794,300	795,300	804,700	800,100	796,100	793,800

Notes: (5) Based on 55 degrees Fahrenheit base and average method.
(6) Based on 65 degrees Fahrenheit base and average method.
(7) Based on average number of customers during the year.
(8) Measurement of summer net dependable capacity under MISO.

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

FORM 10-K

(Mark One)

(X) Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended **December 31, 2016**

( ) Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from_____to_____

Commission File Number 0-53713

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

MINNESOTA	**27-0383995**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
215 SOUTH CASCADE STREET, BOX 496, FERGUS FALLS, MINNESOTA	**56538-0496**
(Address of principal executive offices)	(Zip Code)

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

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

Title of each class	Name of each exchange on which registered
COMMON SHARES, par value $5.00 per share	**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 (X) 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 (X)

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 (X) No ( )

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes (X) No ( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ( )

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" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer (X)	Accelerated Filer ( )
Non-Accelerated Filer ( )	Smaller Reporting Company ( )
(Do not check if a smaller reporting company)	

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

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 30, 2016 was **$1,260,418,253**.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date:
39,410,825 Common Shares ($5 par value) as of February 10, 2017.

Documents Incorporated by Reference: **Proxy Statement for the 2017 Annual Meeting-Portions incorporated by reference into Part III**

FORM 10-K

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DEFINITIONS

The following abbreviations or acronyms are used in the text.
References in this report to "the Company", "we", "us" and "our" are to Otter Tail Corporation.

AEV, Inc.	Aevenia, Inc.
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AQCS	Air Quality Control System
ARO	Accumulated Asset Retirement Obligation
ASC	Accounting Standards Codification
ASC 606	ASC Topic 606—*Revenue from Contracts with Customers*
ASC 718	ASC Topic 718—*Compensation—Stock Compensation*
ASC 815	ASC Topic 815—*Derivatives and Hedging*
ASC 820	ASC Topic 820—*Fair Value Measurement*
ASC 980	ASC Topic 980—*Regulated Operations*
ASM	Ancillary Services Market
ASU	Accounting Standards Update
BACT	Best-Available Control Technology
BART	Best-Available Retrofit Technology
Brookings Project	Brookings-Southeast Twin Cities 345 kV Project
BTD	BTD Manufacturing, Inc.
BTD-Illinois	Miller Welding & Iron Works, Inc.
Btu	British Thermal Unit
CAA	Clean Air Act
CapX2020	Capacity Expansion 2020
CCMC	Coyote Creek Mining Company, L.L.C.
CCR	Coal Combustion Residuals
CIP	Conservation Improvement Program
CO_2	carbon dioxide
CON	Certificate of Need
CPEC	Central Power Electric Cooperative
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction Work in Progress
D.C. Circuit	United States Court of Appeals for the District of Columbia
DENR	Department of Environment and Natural Resources
DRR	Data Requirement Rule
ECR	Environmental Cost Recovery
EEI	Edison Electric Institute
EEP	Energy Efficiency Plan
EPA	Environmental Protection Agency
ESSRP	Executive Survivor and Supplemental Retirement Plan
Exchange Act	The Securities Exchange Act of 1934
Fargo Project	Fargo-Monticello 345 kV Project
FASB	Financial Accounting Standards Board
FCA	Fuel Clause Adjustment
FERC	Federal Energy Regulatory Commission
Foley	Foley Company
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
Impulse	Impulse Manufacturing, Inc.
IRP	Integrated Resource Plan
JPMorgan	JPMorgan Chase Bank, N.A.
JPMS	J.P. Morgan Securities LLC
kV	kiloVolt
kW	kiloWatt
kwh	kilowatt-hour
LSA	Lignite Sales Agreement
MATS	Mercury and Air Toxics Standards
MDU	MDU Resources Group, Inc.
MISO	Midcontinent Independent System Operator, Inc.
MISO Tariff	MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff
MNCIP	Minnesota Conservation Improvement Program
MNDOC	Minnesota Department of Commerce
MPCA	Minnesota Pollution Control Agency
MPU Act	The Minnesota Public Utilities Act
MPUC	Minnesota Public Utilities Commission
MRO	Midwest Reliability Organization
MVP	Multi-Value Project
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NAEMA	North American Energy Marketers Association
NDPSC	North Dakota Public Service Commission
NDRRA	North Dakota Renewable Resource Adjustment
NPDES	National Pollutant Discharge Elimination System
Northern Pipe	Northern Pipe Products, Inc.
NO_x	Nitrogen Oxide
NSP MN	Northern States Power—Minnesota
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
OAG	Minnesota Office of the Attorney General
OTP	Otter Tail Power Company
PACE	Partnership in Assisting Community Expansion
PCOR	Plains CO_2 Reduction Partnership
ppb	parts per billion
PS	Polystyrene
PSD	Prevention of Significant Deterioration
PTCs	Production Tax Credits
PVC	Polyvinyl Chloride
RBOB	Reformulated Blendstock for Oxygenate Blending
RCRA	Resource Conservation and Recovery Act
ROE	Return on Equity
RRA	Renewable Resource Adjustment
RSG	Revenue Sufficiency Guarantee
RTO Adder	Incentive of additional 50-basis points for Regional Transmission Organization participation
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
SF_6	Sulfur Hexaflouride
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
Standex	Standex International Corporation
T.O. Plastics	T.O. Plastics, Inc.
TCR	Transmission Cost Recovery
Varistar	Varistar Corporation
VIC	Voluntary Investigation and Cleanup
VIE	Variable Interest Entity
Vinyltech	Vinyltech Corporation
WIIN	Water Infrastructure Improvements for the Nation

PART I

ITEM 1. Business

a) General Development of Business

Otter Tail Power Company was incorporated in 1907 under the laws of the State of Minnesota. In 2001, the name was changed to "Otter Tail Corporation" to more accurately represent the broader scope of consolidated operations and the name Otter Tail Power Company (OTP) was retained for use by the electric utility. On July 1, 2009 Otter Tail Corporation completed a holding company reorganization whereby OTP, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (the Company). The new parent holding company was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization. The Company's executive offices are located at 215 South Cascade Street, P.O. Box 496, Fergus Falls, Minnesota 56538-0496 and 4334 18th Avenue SW, Suite 200, P.O. Box 9156, Fargo, North Dakota 58106-9156. The Company's telephone number is (866) 410-8780.

The Company makes available free of charge at its website (www.ottertail.com) its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, 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). Information on the Company's website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

Otter Tail Corporation and its subsidiaries conduct business primarily in the United States. The Company had approximately 2,054 full-time employees in its continuing operations at December 31, 2016. The Company's businesses have been classified in three segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision maker. The three segments are Electric, Manufacturing and Plastics.

From 2011 through 2015 the Company sold several businesses in execution of an announced strategy to realign its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations. The following divestitures occurred in this timeframe:

- In 2011, the Company sold Idaho Pacific Holdings, Inc., its Food Ingredient Processing business, and E.W. Wylie Corporation, its flat-bed trucking company.
- In January 2012, the Company sold the assets of Aviva Sports, Inc., a recreational equipment manufacturer.
- In February 2012, the Company sold DMS Health Technologies, Inc., its former Health Services segment business.
- In November 2012, the Company completed the sale of the assets of its former wind tower company.
- On February 8, 2013 the Company sold substantially all the assets of its former dock and boatlift company.
- On February 28, 2015 the Company sold the assets of AEV, Inc., its former energy and electrical construction contractor, and on April 30, 2015 the Company sold Foley Company, its former water, wastewater, power and industrial construction contractor. With the sale of these two companies in 2015 the Company eliminated its Construction segment.

On September 1, 2015 the Company acquired the assets of Impulse Manufacturing Inc. (Impulse) of Dawsonville, Georgia, now operating under the name BTD-Georgia, for a final adjusted payment of $29.3 million in cash. BTD-Georgia offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers.

The chart below indicates the companies included in each of the Company's reporting segments.

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

- **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 Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907.
- **Manufacturing** consists of businesses in the following manufacturing activities: contract machining, metal parts stamping, fabrication and painting, and production of material and handling trays and horticultural containers. 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 upper Midwest and Southwest regions of the United States.

OTP is a wholly owned subsidiary of the Company. The Company's manufacturing and plastic pipe businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar). The Company's corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance that are not allocated to its subsidiary companies. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

The Company has lowered its overall risk by investing in rate base growth opportunities in its Electric segment and divesting certain non-electric operating companies that no longer fit the Company's portfolio criteria. This strategy has provided a more predictable earnings stream, improved the Company's credit quality and preserved its ability to fund the dividend. The Company's goal is to deliver annual growth in earnings per share between four to seven percent over the next several years, using 2016 diluted earnings per share from continuing operations as the base for measurement. The growth is expected to come from the substantial increase in the Company's regulated utility rate base and from planned increased earnings from existing capacity in place at the Company's manufacturing and plastic pipe businesses, including the 2015 acquisition of BTD-Georgia and the facilities expansion and addition of paint services at BTD's Minnesota facilities completed in 2016. The Company will continue to review its business portfolio to see where additional opportunities exist to improve its risk profile, improve credit metrics and generate additional sources of cash to support the growth opportunities in its electric utility. The Company will also evaluate opportunities to allocate capital to potential acquisitions in its Manufacturing and Plastics segments. Over time, the Company expects the electric utility business will provide approximately 75% to 85% of its overall earnings. The Company expects its manufacturing and plastic pipe businesses will provide 15% to 25% of its earnings, and will continue to be a fundamental part of its strategy. The actual mix of earnings from continuing operations in 2016 was 80% from the electric utility and 20% from the manufacturing and plastic pipe businesses, including unallocated corporate costs.

The Company maintains the following criteria in evaluating whether its operating companies are a strategic fit, the operating company:

- Maintains a threshold level of net earnings and a return on invested capital in excess of the Company's weighted average cost of capital.
- Has a strategic differentiation from competitors and a sustainable cost advantage.
- Operates within a stable and growing industry and is able to quickly adapt to changing economic cycles.
- Has a strong management team committed to operational excellence.

For a discussion of the Company's results of operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations," on pages 31 through 46 of this Annual Report on Form 10-K.

(b) Financial Information about Industry Segments

The Company is engaged in businesses classified into three segments: Electric, Manufacturing and Plastics. Financial information about the Company's segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 61 through 62 of this Annual Report on Form 10-K.

(c) Narrative Description of Business

ELECTRIC

GENERAL

Electric includes OTP which is headquartered in Fergus Falls, Minnesota, and provides electricity to more than 130,000 customers in a service area encompassing 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. The Company derived 53%, 52% and 51% of its consolidated operating revenues and 81%, 80% and 76% of its consolidated operating income from its Electric segment for the years ended December 31, 2016, 2015 and 2014, respectively.

The breakdown of retail electric revenues by state is as follows:

State	2016	2015
Minnesota	**53.0%**	50.4%
North Dakota	**38.4**	40.6
South Dakota	**8.6**	9.0
Total	**100.0%**	100.0%

The territory served by OTP is predominantly agricultural. The aggregate population of OTP's retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 126,000 people live in communities having a population of more than 1,000, according to the 2010 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,427); Bemidji, Minnesota (13,431); and Fergus Falls, Minnesota (13,138). As of December 31, 2016 OTP served 131,546 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant.

The following table provides a breakdown of electric revenues by customer category. All other sources include gross wholesale sales from utility generation, net revenue from energy trading activity and sales to municipalities.

Customer Category	2016	2015
Commercial	**36.1%**	35.4%
Residential	**30.8**	32.1
Industrial	**31.0**	29.9
All Other Sources	**2.1**	2.6
Total	**100.0%**	100.0%

CAPACITY AND DEMAND

As of December 31, 2016 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants	
Big Stone Plant	255,800 kW
Coyote Station	149,800
Hoot Lake Plant	140,100
Total Baseload Net Plant	545,700 kW
Combustion Turbine and Small Diesel Units	108,100 kW
Hydroelectric Facilities	2,500 kW
Owned Wind Facilities (rated at nameplate)	
Luverne Wind Farm (33 turbines)	49,500 kW
Ashtabula Wind Center (32 turbines)	48,000
Langdon Wind Center (27 turbines)	40,500
Total Owned Wind Facilities	138,000 kW

The baseload net plant capacity for Big Stone Plant and Coyote Station constitutes OTP's ownership percentages of 53.9% and 35%, respectively. OTP owns 100% of the Hoot Lake Plant. During 2016, about 54% of OTP's retail kwh sales were supplied from OTP generating plants with the balance supplied by purchased power.

In addition to the owned facilities described above, OTP had the following purchased power agreements in place on December 31, 2016:

Purchased Wind Power Agreements	
(rated at nameplate and greater than 2,000 kW)	
Ashtabula Wind III	62,400 kW
Edgeley	21,000
Langdon	19,500
Total Purchased Wind	102,900 kW

Purchase of Capacity	
(in excess of 1 year and 500 kW)	
Great River Energy *(1)*	100,000 kW

(1) 100,000 kiloWatt (kW) through May 2017, 25,000 kW June 2017–May 2019, and 50,000 kW June 2019–May 2021.

OTP has a direct control load management system which provides some flexibility to OTP to effect reductions of peak load. OTP also offers rates to customers which encourage off-peak usage.

OTP's capacity requirement is based on MISO Module E requirements. OTP is required to have sufficient Zonal Resource Credits to meet its monthly weather normalized forecast demand, plus a reserve obligation. OTP met its MISO obligation for the 2016-2017 MISO planning year. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2017 system demand and MISO reserve requirements.

FUEL SUPPLY

Coal is the principal fuel burned at the Big Stone, Coyote and Hoot Lake generating plants. Coyote Station, a mine-mouth facility, burns North Dakota lignite coal. Hoot Lake Plant and Big Stone Plant burn western subbituminous coal.

The following table shows the sources of energy used to generate OTP's net output of electricity for 2016 and 2015:

	2016		2015	
Sources	**Net kwhs Generated (Thousands)**	**% of Total kwhs Generated**	Net kwhs Generated (Thousands)	% of Total kwhs Generated
Subbituminous Coal	**1,419,901**	**50.3%**	1,132,335	49.1%
Lignite Coal	**844,225**	**29.9**	662,450	28.7
Wind and Hydro	**517,396**	**18.4**	493,276	21.4
Natural Gas and Oil	**40,257**	**1.4**	17,907	0.8
Total	**2,821,779**	**100.0%**	2,305,968	100.0%

OTP has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Contura Coal Sales, LLC	Wyoming subbituminous	December 31, 2017
Big Stone Plant	Peabody COALSALES, LLC	Wyoming subbituminous	December 31, 2017
Coyote Station	Coyote Creek Mining Company, L.L.C.	North Dakota lignite	December 31, 2040
Hoot Lake Plant	Cloud Peak Energy Resources LLC	Montana subbituminous	December 31, 2023

OTP's anticipated coal needs for Big Stone Plant are secured under contract through December 2017.

In October 2012 the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of 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 being paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. The LSA provides for the Coyote Station owners to purchase the membership interests in CCMC in the event of certain early termination events and also at the end of the term of the LSA.

OTP's coal supply requirements for Hoot Lake Plant are secured under contract through December 2023.

Railroad transportation services to the Big Stone Plant and Hoot Lake Plant are provided under a common carrier rate by the BNSF Railway. The common carrier rate is subject to a mileage-based methodology to assess a fuel surcharge. The basis for the fuel surcharge is the U.S. average price of retail on-highway diesel fuel. No coal transportation agreement is needed for Coyote Station due to its location next to a coal mine.

The average cost of fuel consumed (including handling charges to the plant sites) per million British Thermal Units (Btu) for the years 2016, 2015, and 2014 was $2.146, $2.281 and $2.036, respectively.

GENERAL 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 certain interstate operations.

A breakdown of electric rate regulation by each jurisdiction is as follows:

		2016		2015	
Rates	Regulation	% of Electric Revenues	% of kwh Sales	% of Electric Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	**47.5%**	**54.0%**	47.2%	52.0%
ND Retail Sales	ND Public Service Commission	**34.4**	**37.1**	38.0	38.7
SD Retail Sales	SD Public Utilities Commission	**7.8**	**8.9**	8.5	9.3
Transmission & Wholesale	Federal Energy Regulatory Commission	**10.3**	**—**	6.3	—
Total		**100.0%**	**100.0%**	100.0%	100.0%

OTP operates under approved retail electric tariffs in all three states it serves. OTP has an obligation to serve any customer requesting service within its assigned service territory. The pattern of electric usage can vary dramatically during a 24-hour period and from season to season. OTP's tariffs are designed to recover the costs of providing electric service. To the extent peak usage can be reduced or shifted to periods of lower usage, the cost to serve all customers is reduced. In order to shift usage from peak times, OTP has approved tariffs in all three states for residential demand control, general service time of use and time of day, real-time pricing, and controlled and interruptible service. Each of these specialized rates is designed to improve efficient use of OTP resources, while giving customers more control over their electric bill. OTP also has approved tariffs in its three service territories which allow qualifying customers to release and sell energy back to OTP when wholesale energy prices make such transactions desirable.

With a few minor exceptions, OTP's electric retail rate schedules provide for adjustments in rates based on the cost of fuel delivered to OTP's generating plants, as well as for adjustments based on the cost of electric energy purchased by OTP. OTP also credits certain margins from wholesale sales to the fuel and purchased power adjustment. The adjustments for fuel and purchased power costs are presently based on a two month moving average in Minnesota and by the Federal Energy Regulatory Commission (FERC), a three month moving average in South Dakota and a four month moving average in North Dakota. These adjustments are applied to the next billing period after becoming applicable. These adjustments also include an over or under recovery mechanism, which is calculated on an annual basis in Minnesota and on a monthly basis in North Dakota and South Dakota.

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of the material regulations of each jurisdiction applicable to OTP's electric operations, as well as any specific electric rate proceedings during the last three years with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC. The Company's manufacturing and plastic pipe businesses are not subject to direct regulation by any of these agencies.

MAJOR CAPITAL EXPENDITURE PROJECTS

The Big Stone South—Brookings MVP and CapX2020 Project—This 345 kiloVolt (kV) transmission line, currently under construction, will extend approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power–MN (NSP MN), a subsidiary of Xcel Energy Inc., jointly developed this project, and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as a Multi-Value Project (MVP) under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the third quarter of 2015 and the line is expected to be in service in fall 2017. OTP's total capital investment in this project is expected to be approximately $80 million, which includes certain assets that will be owned 100% by OTP.

The Big Stone South—Ellendale MVP—This is a 345 kV transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (MDU), and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's total capital investment in this project is expected to be approximately $149 million, which includes certain assets that will be owned 100% by OTP.

Capacity Expansion 2020 (CapX2020) Transmission Line Projects—CapX2020 is a joint initiative of eleven investor-owned, cooperative, and

municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service.

Fargo–Monticello 345 kV CapX2020 Project (the Fargo Project)—OTP has invested approximately $81 million and has a 14.2% ownership interest in the jointly-owned assets of this 240-mile transmission line, and owns 100% of certain assets of the project. The final phase of this project was energized on April 2, 2015.

Brookings–Southeast Twin Cities 345 kV CapX2020 Project (the Brookings Project)—OTP has invested approximately $26 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. The final segments of this line were energized on March 26, 2015.

Big Stone Plant Air Quality Control System (AQCS)—OTP completed construction and testing of the Big Stone Plant AQCS in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. OTP's capitalized cost of the project, excluding allowance for funds used during construction, was approximately $200 million.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

MINNESOTA

Under the Minnesota Public Utilities Act, OTP is subject to the jurisdiction of the MPUC with respect to rates, issuance of securities, depreciation rates, public utility services, construction of major utility facilities, establishment of exclusive assigned service areas, contracts and arrangements with subsidiaries and other affiliated interests, and other matters. The MPUC has the authority to assess the need for large energy facilities and to issue or deny certificates of need, after public hearings, within one year of an application to construct such a facility.

Pursuant to the Minnesota Power Plant Siting Act, the MPUC has authority to select or designate sites in Minnesota for new electric power generating plants (50,000 kW or more) and routes for transmission lines (100 kV or more) in an orderly manner compatible with environmental preservation and the efficient use of resources, and to certify such sites and routes as to environmental compatibility after an environmental impact study has been conducted by the Minnesota Department of Commerce (MNDOC) and the Office of Administrative Hearings has conducted contested case hearings.

The Minnesota Division of Energy Resources, part of the MNDOC, is responsible for investigating all matters subject to the jurisdiction of the MNDOC or the MPUC, and for the enforcement of MPUC orders. Among other things, the MNDOC is authorized to collect and analyze data on energy including the consumption of energy, develop recommendations as to energy policies for the governor and the legislature of Minnesota and evaluate policies governing the establishment of rates and prices for energy as related to energy conservation. The MNDOC also has the power, in the event of energy shortage or for a long-term basis, to prepare and adopt regulations to conserve and allocate energy.

2016 General Rate Case—On February 16, 2016 OTP filed a request with the MPUC for an increase in revenue recoverable under general rates in Minnesota. In its filing, OTP requested an allowed rate of return on rate base of 8.07% and an allowed rate of return on equity of 10.4% based on an equity ratio of 52.5% of total capital. On April 14, 2016 the MPUC issued an order approving an interim rate increase of 9.56% to the base rate portion of customers' bills effective April 16, 2016, as modified and subject to refund. The request and interim rate information is detailed in the table below:

($ in thousands)	Annualized or Test Year	Actual Through December 31, 2016
Revenue Increase Requested	$ 19,296	
Increase Percentage Requested	9.80%	
Jurisdictional Rate Base	$ 483,000	
Interim Revenue Increase (subject to refund)	$ 16,816	$ 10,976

The major components of the requested rate increase are summarized below:

Revenue Requirement Deficiency Cost Factors *(in thousands)*	2016 Test Year Allocation
Increased Rate Base	$ 10,000
Increased Expenses	7,700
Other	1,596
Total Requested Revenue Increase	$ 19,296
Excluded from Interim Rates:	
Rate Base Effect of Prepaid Pension Asset	(2,480)
Approved Interim Revenue Increase (subject to refund)	$ 16,816

The deadline for submission of intervenor direct testimony was August 16, 2016. Direct testimony of the MNDOC included a recommendation for an 8.87% allowed rate of return on equity, and direct testimony of the Minnesota Office of the Attorney General (OAG) included a recommendation for a 6.96% allowed rate of return on equity. In response, in rebuttal testimony, OTP modified its request to provide for an allowed rate of return on equity of 10.05%. In rebuttal testimony, the MNDOC revised its recommendation to an 8.66% allowed rate of return on equity, and the Minnesota OAG revised its recommendation to a 7.14% allowed rate of return on equity. Hearings before the Administrative Law Judge (ALJ) occurred in October 2016. On January 5, 2017 the ALJ's report was issued which included a recommendation for a 9.54% allowed rate of return on equity.

Based on OTP's modifications to its original request and other expected outcomes in the aforementioned rate case, OTP has recorded an estimated interim rate refund of $3.6 million as of December 31, 2016. Oral arguments before the MPUC are expected to occur in late February 2017. The MPUC is expected to make its final decision in March 2017 and issue its written order in spring 2017.

2010 General Rate Case—OTP's most recently completed general rate increase in Minnesota of approximately $5.0 million, or 1.6%, was granted by the MPUC in an order issued on April 25, 2011 and effective October 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%.

Integrated Resource Plan (IRP)—Minnesota law requires utilities to submit to the MPUC for approval a 15-year advance IRP. A resource plan is a set of resource options a utility could use to meet the service needs of its customers over a 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 resource plans shall be considered prima facie evidence, subject to rebuttal, in Certificate of Need (CON) hearings, rate reviews and other proceedings. Typically, the filings are submitted every two years.

On December 5, 2014 the MPUC issued an order approving OTP's 2014-2028 IRP filing, which included the following items:

- Authorization to add up to 300 MW of wind between 2017 and 2021 if it is cost effective and does not negatively impact OTP's electric system operation.

- Construction of solar generation sufficient to comply with the Minnesota Solar Energy Standard by 2020.
- Confirmation of a 1.5% energy savings goal, as filed in OTP's triennial Minnesota Conservation Improvement Program (MNCIP) plan.
- Authorization to obtain 200 MW, subject to need, of intermediate natural gas generation in the 2019-2021 timeframe.

On September 14, 2015 the MPUC granted OTP a six-month extension to June 1, 2016 to file its latest IRP. The extension allowed OTP time to model compliance with final rules on proposed standards of performance for carbon dioxide (CO_2) emissions from fossil fuel-fired power plants published by the Environmental Protection Agency (EPA) on October 23, 2015 and to incorporate planned wind and natural gas-fired generation additions.

OTP filed its 2017-2031 IRP with the MPUC on June 1, 2016, which included the following items:

- Adding 200 megawatts (MW) of wind resources (100 MW in 2018 and 100 MW in 2020) and authorization to add up to 100 MW more at a later time. With three 100-MW additions to OTP's wind energy resources, wind would serve approximately 34% of OTP's customers' energy needs.
- Adding 30 MW of solar resources by 2020 to comply with Minnesota's Solar Energy Standard.
- Adding a 248 MW simple-cycle natural gas-fired plant in 2021 to replace Hoot Lake Plant's two coal-fired steam turbines to be retired in 2021. The natural gas-fired plant will likely be located in close proximity to a high-voltage transmission line and a large natural gas pipeline within OTP's service area.

OTP expects the MPUC hearing on the 2017-2031 IRP to occur in late February or early March 2017.

Renewable Energy Standards, Conservation, Renewable Resource Riders—Minnesota law favors conservation over the addition of new resources. In addition, Minnesota law requires the use of renewable resources where new supplies are needed, unless the utility proves that a renewable energy facility is not in the public interest. An existing environmental externality law requires the MPUC, to the extent practicable, to quantify the environmental costs associated with each method of electricity generation, and to use such monetized values in evaluating generation resources. The MPUC must disallow any nonrenewable rate base additions (whether within or outside of the state) or any related rate recovery, and may not approve any nonrenewable energy facility in an IRP, unless the utility proves that a renewable energy facility is not in the public interest. The state has prioritized the acceptability of new generation with wind and solar ranked first and coal and nuclear ranked fifth, the lowest ranking. The MPUC's current estimate of the range of costs of future CO_2 regulation to be used in modeling analyses for resource plans is $9 to $34/ton of CO_2 commencing in 2022. The MPUC is required to annually update these estimates.

Minnesota has a renewable energy standard which requires OTP 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: 17% by 2016; 20% by 2020 and 25% by 2025. In addition, Minnesota law requires 1.5% of total Minnesota electric sales by public utilities to be supplied by solar energy by 2020. 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 20 kWs or less. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired sufficient renewable resources to currently comply with Minnesota renewable energy standards. OTP is evaluating potential options for maintaining compliance and meeting the solar energy standard. OTP's projected capital expenditures include $40 million for a solar project in 2019. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standard. The MPUC is authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

Minnesota Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

On September 26, 2014 the MPUC approved OTP's 2013 financial incentive request for $4.0 million, an updated surcharge rate to be effective October 1, 2014, as well as a change to the carrying charge to be equal to the short term cost of debt set in OTP's most recent general rate case.

OTP recognized a financial incentive for 2014 of $3.0 million due, in part, to the MPUC lowering the MNCIP financial incentive from approximately $0.09 per kwh saved for 2013-2015 to $0.07 per kwh saved for 2014-2016. Additionally, OTP saved approximately 2 million less kwhs in 2014 compared with 2013 under conservation improvement programs in Minnesota. On July 9, 2015 the MPUC granted approval of OTP's 2014 financial incentive of $3.0 million along with an updated surcharge with an effective date of October 1, 2015.

Based on results from the 2015 MNCIP program year, OTP recognized a financial incentive of $4.2 million. The 2015 MNCIP program resulted in an approximate 39% increase in energy savings compared to 2014 program results. On April 1, 2016 OTP requested approval for recovery of its 2015 MNCIP program costs not included in base rates, a $4.3 million financial incentive and an update to the MNCIP surcharge from the MPUC. On July 19, 2016 the MPUC issued an order approving OTP's request with an effective date of October 1, 2016.

Based on results from the 2016 MNCIP program year, OTP recognized a financial incentive of $5.1 million in 2016. The 2016 program resulted in an approximate 18% increase in energy savings compared to 2015 program results. OTP will request approval for recovery of its 2016 MNCIP program costs not included in base rates, a $5.1 million financial incentive and an update to the MNCIP surcharge from the MPUC by April 1, 2017.

On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model will provide utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

In 2016 the MNDOC opened an additional docket to investigate how investor-owned utilities calculate their avoided costs pertaining to generation capacity, energy, transmission and distribution. Avoided costs are the basis of MNCIP program benefits which, going forward, will establish OTP's financial incentive. On May 23, 2016 the MNDOC accepted OTP's 2017 avoided costs calculation, but is requiring Minnesota investor-owned utilities to undergo an analysis of transmission and distribution avoided costs for 2018 and 2019. OTP is participating in a stakeholder group with the MNDOC, Xcel Energy Inc., and Minnesota Power to determine the best method for calculating avoided costs. Results from this work should be submitted to the MNDOC in the second quarter of 2017.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a CON proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

OTP filed an annual update to its Minnesota TCR rider on February 7, 2013 to include three new projects as well as updated costs associated with existing projects. In a written order issued on March 10, 2014, the MPUC approved OTP's 2013 TCR rider update but found capitalized internal costs, costs in excess of CON estimates and a carrying charge ineligible for recovery through the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP is seeking recovery of the capitalized internal costs and costs in excess of CON estimates in its current general rate case filing in Minnesota. In response to the MPUC's approval of OTP's annual TCR update, OTP submitted a compliance filing in April 2014 reflecting the TCR rider revenue requirements changes relating to the MPUC's ruling and requesting no rate change be implemented at the time. The MPUC approved OTP's compliance filing on June 19, 2014. On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015. OTP filed an annual update to its Minnesota TCR rider on September 30, 2015 requesting revenue recovery of approximately $7.8 million. A supplemental filing to the update was made on December 21, 2015 to address an issue surrounding the proration of accumulated deferred income taxes and, in an unrelated adjustment, the TCR rider update revenue request was reduced to $7.2 million. On March 9, 2016 the MPUC issued an order approving OTP's annual update to its TCR rider, with an effective date of April 1, 2016.

OTP filed an update to its TCR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis, as recommended by the MNDOC. The proposed rate changes went into effect on September 1, 2016. The MPUC granted extensions to the MNDOC to file initial comments in this docket until February 2, 2017.

In OTP's 2016 general rate case, the MNDOC has argued that the MPUC should require OTP to include in the TCR rider retail rate base 100% of OTP's investment in the Big Stone South—Brookings and Big Stone South—Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. OTP has opposed this treatment, arguing the projects are appropriately assigned to the FERC jurisdiction, and the FERC's determination of the projects' revenue requirements should not be altered by forcing the revenues into the retail revenue requirement calculations. In the general rate case proceeding, the ALJ recommended that the MPUC should affirm OTP's treatment. If the MPUC finds that the MNDOC's treatment should be followed, it would result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time.

Environmental Cost Recovery (ECR) Rider—On December 18, 2013 the MPUC granted approval of OTP's Minnesota ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS effective January 1, 2014. The ECR rider recoverable revenue requirements included a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's 2010 general rate case. The MPUC approved OTP's 2014 ECR rider annual update request on November 24, 2014 with an effective date of December 1, 2014. OTP filed its 2015 annual update on July 31, 2015, with a request to keep the 2014 annual update rate in place. On December 21, 2015 OTP filed a supplemental filing with updated financial information. The MPUC issued an order on March 9, 2016 approving OTP's request to leave the 2014 annual update rate in place. OTP filed an update to its Minnesota ECR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request, with an effective date of September 1, 2016. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis and has since granted extensions to the MNDOC to file initial comments in this docket until February 2, 2017. Reply comments were due from OTP on February 13, 2017.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs are included in OTP's 2016 general rate case in Minnesota and are being considered for recovery either through the FCA rider or general rates. These costs are currently being expensed as incurred.

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 the capital structure for OTP. Once the petition is 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 capital structure petition. The MPUC approved OTP's most recent capital structure petition on August 2, 2016, allowing for an equity to total capitalization ratio between 47.5% and 58.1%, with total capitalization not to exceed $1,123,168,000 until the MPUC issues a new

capital structure order for 2017. OTP is required to file its 2017 capital structure petition no later than May 1, 2017.

NORTH DAKOTA

OTP is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities, construction of major utility facilities and other matters. The NDPSC periodically performs audits of gas and electric utilities over which it has rate setting jurisdiction to determine the reasonableness of overall rate levels. In the past, these audits have occasionally resulted in settlement agreements adjusting rate levels for OTP.

The North Dakota Energy Conversion and Transmission Facility Siting Act grants the NDPSC the authority to approve sites in North Dakota for large electric generating facilities and high voltage transmission lines. This Act is similar to the Minnesota Power Plant Siting Act described above and applies to proposed wind energy electric power generating plants exceeding 500 kW of electricity, non-wind energy electric power generating plants exceeding 50,000 kW and transmission lines with a design in excess of 115 kV. OTP is required to submit a ten-year plan to the NDPSC biennially.

The NDPSC reserves the right to review the issuance of stocks, bonds, notes and other evidence of indebtedness of a public utility. However, the issuance by a public utility of securities registered with the SEC is expressly exempted from review by the NDPSC under North Dakota state law.

General Rates—OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment. The NDPSC approved OTP's 2013 annual update to its NDRRA on March 12, 2014 with an effective date of April 1, 2014, which resulted in a 13.5% reduction in the NDRRA rate. The NDPSC approved OTP's 2014 annual update to the NDRRA, including a change in rate design from an amount per kwh consumed to a percentage of a customer's bill, on March 25, 2015 with an effective date of April 1, 2015. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016. On February 25, 2016 OTP made a supplemental filing to address the impact of bonus depreciation for income taxes and related deferred tax assets on the NDRRA, as well as an adjustment to the estimated amount of Federal Production Tax Credits used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflects a reduction in the return on equity (ROE) component of the rate from 10.75%, approved in OTP's most recent general rate case, to 10.50%. OTP submitted its 2016 annual update to the NDRRA rider rate on December 30, 2016, requesting a decrease to the NDRRA rate from 7.573% to 7.005%, with a requested implementation date of April 1, 2017.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case. The NDPSC approved OTP's 2014 annual update to its TCR rider rate on December 17, 2014 with an effective date of January 1, 2015. On August 31, 2015 OTP filed its 2015 annual update to its North Dakota TCR rider rate requesting recovery of approximately $10.2 million for 2016 compared with $8.5 million for 2015, including costs assessed by the MISO as well as new costs from the Southwest Power Pool (SPP) that OTP began incurring January 1, 2016. These new costs are associated with OTP's load connected to the transmission system of Central Power Electric Cooperative (CPEC). OTP's load became subject to SPP transmission-related charges when CPEC transmission assets were added to the SPP. The NDPSC approved OTP's 2015 annual update to its TCR rider rate on December 16, 2015, with an effective date of January 1, 2016. On September 1, 2016 OTP filed its annual update to the TCR rider requesting a revenue requirement of $5.7 million, which includes a reduction of $2.6 million for a projected over-collection for 2016. Primary drivers of the decrease from the 2015 updated rider rate include the impact of federal bonus depreciation and unresolved MISO ROE complaint proceedings. OTP filed a supplemental filing on September 14, 2016, requesting that the over-collection balance be spread over the next two years for purposes of reducing the volatility of the rates from year to year. The NDPSC approved the update on December 14, 2016. The new rates went into effect on January 1, 2017.

Environmental Cost Recovery Rider—On December 18, 2013 the NDPSC approved OTP's request for an ECR rider to recover OTP's North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS. The ECR provides for a current return on CWIP and a return on investment at the level approved in OTP's most recent general rate case. On March 31, 2014 OTP filed an annual update to its North Dakota ECR rider rate. The update included a request to increase the ECR rider rate from 4.319% of base rates to 7.531% of base rates. The NDPSC approved OTP's 2014 ECR rider annual update request on July 10, 2014 with an August 1, 2014 implementation date. On March 31, 2015 OTP filed its annual update to the ECR. This update included a request to increase the ECR rider rate from 7.531% to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015, along with the approval of recovery of OTP's North Dakota jurisdictional share of Hoot Lake Plant Mercury and Air Toxics Standards (MATS) project costs.

On March 31, 2016 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 9.193% to 7.904% of base rates, or a revenue requirement reduction from $12.2 million to $10.4 million, effective July 1, 2016. The rate reduction request was primarily due to the Company's 2015 bonus depreciation election for income taxes, which reduces revenue requirements. The filing was approved on June 22, 2016.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the NDPSC to revise its FCA rider in North Dakota to include recovery of new reagent and emission allowance costs. On February 25, 2015 the NDPSC approved recovery of these costs through modification of the ECR rider, instead of recovery through the FCA as OTP had proposed. The ECR rider reagent and emissions allowance charge became effective May 1, 2015.

SOUTH DAKOTA

Under the South Dakota Public Utilities Act, OTP is subject to the jurisdiction of the SDPUC with respect to rates, public utility services, construction of major utility facilities, establishment of assigned service areas and other matters. Under the South Dakota Energy Facility Permit Act, the SDPUC has the authority to approve sites in South Dakota for large energy conversion facilities (100,000 kW or more) and transmission lines with a design of 115 kV or more.

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately $643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective

with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. The SDPUC approved OTP's 2013 annual update on February 18, 2014 with an effective date of March 1, 2014. The SDPUC approved OTP's 2014 annual update on February 13, 2015 with an effective date of March 1, 2015. OTP filed its 2015 annual update on October 30, 2015 with a proposed effective date of March 1, 2016. A supplemental filing was made on February 3, 2016 to true-up the filing to include the impact of bonus depreciation elected for 2015, the inclusion of a deferred tax asset relating to a net operating loss and the proration of accumulated deferred income taxes. This update included the recovery of new SPP transmission costs OTP began to incur on January 1, 2016. On February 12, 2016 the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2016. On November 1, 2016 OTP filed the annual update to the South Dakota TCR rider. OTP made a supplemental filing on January 20, 2017 to include updated costs through December 2016 as well as updated forecast information. The proposed effective date of the new rates is March 1, 2017.

Environmental Cost Recovery Rider—On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover OTP's South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects, with an effective date of December 1, 2014. On August 31, 2015 OTP filed its annual update to the South Dakota ECR requesting recovery of approximately $2.7 million in annual revenue. The SDPUC approved the request on October 15, 2015 with an effective date of November 1, 2015. On August 31, 2016 OTP filed its 2016 update to the ECR rider, requesting recovery of approximately $2.3 million in annual revenue. The SDPUC approved the request on October 26, 2016 with an effective date of November 1, 2016. The lower revenue requirement is a result of the implementation of federal bonus depreciation taken on the Big Stone Plant AQCS.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

Energy Efficiency Plan (EEP)—The SDPUC has encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use. The plan is being implemented with program costs, carrying costs and a financial incentive being recovered through an approved rider.

On May 1, 2014 OTP filed a request with the SDPUC for approval of updates to its EEP based on 2013 results. On August 26, 2014 the SDPUC issued a written order approving the maximum available incentive payment limited to 30% of the budget amount provided in the EEP, or $84,000. In addition to the incentive payment approval, the SDPUC approved OTP's proposal to leave the South Dakota Energy Efficiency Adjustment Rider at $0.00103/kwh.

On May 1, 2015 OTP filed its 2014 South Dakota EEP Status Report, financial incentive and surcharge adjustment along with a request for approval of an incentive of $105,000 and EEP surcharge increase to $0.00152/kwh. On July 14, 2015 the SDPUC issued a written order approving OTP's 2014 EEP Status Report, incentive and surcharge increases.

On April 29, 2016 OTP filed its 2015 South Dakota EEP Status Report, financial incentive and surcharge adjustment with the SDPUC. The filing requested approval of an incentive of $105,900 and a decrease in the EEP surcharge from $0.00152/kwh to $0.00114/kwh effective July 1, 2016. The SDPUC approved the request. On April 29, 2016 OTP also filed its 2017-2019 goals and budgets for its South Dakota EEP triennial plan. For the 2017, 2018 and 2019 EEP planning years, OTP has proposed energy savings goals and budgets of 3,804,094 kwh and $449,000 in 2017, 3,805,177 kwh and $449,000 in 2018 and 3,806,262 kwh and $449,000 in 2019. On November 22, 2016 the SDPUC approved OTP's 2017-2019 EEP triennial plan with certain conditions.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935, as amended. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing.

Effective January 1, 2012 the FERC authorized OTP to recover 100% of prudently incurred CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVPs in MISO's 2011 Transmission Expansion Plan: the Big Stone South–Brookings MVP and the Big Stone South–Ellendale MVP.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. On October 16, 2014 the FERC issued an order finding that the current MISO ROE may be unjust and unreasonable and setting the issue for hearing. Parties, including OTP, sought rehearing of the FERC's decision to set the November 12, 2013 complaint for hearing. This rehearing was denied on July 21, 2016. On September 19, 2016 the MISO transmission owners sought appeal to the United States Court of Appeals for the District of Columbia (D.C. Circuit). A non-binding decision by the presiding ALJ was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the

complaint for hearings before an ALJ, which were held the week of February 16, 2016. Parties, including OTP, sought rehearing of the FERC's decision to set the November 12, 2013 complaint for hearing. This rehearing was denied on July 21, 2016. On September 19, 2016 the MISO transmission owners sought appeal to the D.C. Circuit. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. The FERC is expected to issue its order not earlier than spring 2017.

Based on a potential reduction by the FERC in the ROE component of the MISO Tariff, OTP recorded reductions in revenue of $1.6 million in 2016 and $1.1 million in 2015 and has a $2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with FERC to market participants, revisions to the RSG rate based on several FERC orders and FERC's decision to resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. These consolidated cases are currently held in abeyance while the parties engage in mediation before the D.C. Circuit. OTP is an intervenor in these cases and a participant in mediation. The scope of the issues that will be subject to appeal at the D.C. Circuit have not yet been finalized. In addition, MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, the Company cannot estimate OTP's exposure at this time from a final order reversing the relevant FERC orders. Although the Company cannot estimate OTP's exposure at this time, a final order reversing the relevant FERC orders could have a material adverse effect on the Company's results of operations.

NAEMA

OTP is a member of the North American Energy Marketers Association (NAEMA) which is an independent, non-profit trade association representing entities involved in the marketing of energy or in providing services to the energy industry. NAEMA has over 150 members with operations in 48 states and Canada. Power pool sales are conducted continuously through NAEMA in accordance with schedules filed by NAEMA with the FERC.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC)

NERC is an international regulatory authority, subject to oversight by the FERC and governmental authorities in Canada, whose mission is to assure the reliability of the bulk power system in North America. As an owner and operator within the bulk power system, OTP is required to comply with NERC reliability standards, including standards on cybersecurity and protection of critical infrastructure. The FERC approved NERC's critical infrastructure and protection standards in November 2014.

MIDWEST RELIABILITY ORGANIZATION (MRO)

OTP is a member of the MRO. The MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO began operations in 2005 and is one of eight regional entities in North America operating under authority from regulators in the United States and Canada through a delegation agreement with the NERC. The MRO is responsible for: (1) developing and implementing reliability standards, (2) enforcing compliance with those standards, (3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity, and (4) providing an appeals and dispute resolution process.

The MRO region covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska and the majority of the territory in the states of South Dakota, Iowa and Wisconsin. The region includes more than 130 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, independent power producers and others who have interests in the reliability of the bulk power system.

To ensure our compliance with NERC standards, the MRO periodically audits OTP. OTP's most recent audit began with a notification in October 2015 and MRO audit staff conducted fieldwork in January 2016. On January 23, 2017 OTP received its draft audit report from the MRO audit team. Based on the results of their fieldwork and subsequent discussions with OTP, the MRO found no potential violations at OTP.

MISO

OTP is a member of the MISO. As the transmission provider and security coordinator for the region, the MISO seeks to optimize the efficiency of the interconnected system, provide regional 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. The MISO covers a broad region containing all or parts of 15 states and the Canadian province of Manitoba. The MISO has operational control of OTP's transmission facilities above 100 kV, but OTP continues to own and maintain its transmission assets.

Through the MISO Energy Markets, MISO seeks to develop options for energy supply, increase utilization of transmission assets, optimize the use of energy resources across a wider region and provide greater visibility of data. MISO aims to facilitate a more cost-effective and efficient use of the wholesale bulk electric system.

The MISO Ancillary Services Market (ASM) facilitates the provision of Regulation, Spinning Reserve and Supplemental Reserves. The ASM integrates the procurement and use of regulation and contingency reserves with the existing Energy Market. OTP has actively participated in the market since its commencement.

OTHER

OTP is subject to various federal laws, including the Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992 (which are intended to promote the conservation of energy and the development and use of alternative energy sources) and the Energy Policy Act of 2005.

COMPETITION, DEREGULATION AND LEGISLATION

Electric sales are subject to competition in some areas from municipally owned systems, rural electric cooperatives and, in certain respects, from on-site generators and cogenerators. Electricity also competes with other forms of energy. The degree of competition may vary from time to time depending on relative costs and supplies of other forms of energy.

The Company believes OTP is well positioned to be successful in a competitive environment. A comparison of OTP's electric retail rates to the rates of other investor-owned utilities, cooperatives and municipals in the states OTP serves indicates OTP's rates are competitive.

Legislative and regulatory activity could affect operations in the future. OTP cannot predict the timing or substance of any future legislation or regulation. The Company does not expect retail competition to come to the states of Minnesota, North Dakota or South Dakota in the foreseeable future. There has been no legislative action regarding electric retail choice in any of the states where OTP operates. The Minnesota legislature has in the past considered legislation that, if passed, would have limited the

Company's ability to maintain and grow its nonelectric businesses.

OTP is unable to predict the impact on its operations resulting from future regulatory activities, from future legislation or from future taxes that may be imposed on the source or use of energy.

ENVIRONMENTAL REGULATION

Impact of Environmental Laws—OTP's existing generating plants are subject to stringent federal and state standards and regulations regarding, among other things, air, water and solid waste pollution. In the five years ended December 31, 2016 OTP invested approximately $210 million in environmental control facilities. The 2017 and 2018 construction budgets include approximately $6 million and $5 million, respectively, for environmental equipment for existing facilities.

Air Quality—Criteria Pollutants—Pursuant to the Clean Air Act (CAA), the EPA has promulgated national primary and secondary standards for certain air pollutants.

The primary fuels burned by OTP's steam generating plants are North Dakota lignite coal and western subbituminous coal. Electrostatic precipitators have been installed at the principal units at the Hoot Lake Plant. The Hoot Lake Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The South Dakota Department of Environment and Natural Resources (DENR) issued a Title V Operating Permit to the Big Stone Plant on June 9, 2009, allowing for operation. The Big Stone Plant continues to operate under Title V permit provisions. The Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The Coyote Station is equipped with sulfur dioxide (SO_2) removal equipment. The removal equipment—referred to as a dry scrubber—consists of a spray dryer, followed by a fabric filter, and is designed to desulfurize hot gases from the stack. The fabric filter collects spray dryer residue along with the fly ash. The Coyote Station is currently operating within all presently applicable federal and state air quality and emission standards.

The CAA, in addressing acid deposition, imposed requirements on power plants in an effort to reduce national emissions of SO_2 and nitrogen oxides (NO_x).

The national Acid Rain Program SO_2 emission reduction goals are achieved through a market based system under which power plants are allocated "emissions allowances" that require plants to either reduce their SO_2 emissions or acquire allowances from others to achieve compliance. Each allowance is an authorization to emit one ton of SO_2. SO_2 emission requirements are currently being met by all of OTP's generating facilities without the need to acquire additional allowances for compliance with the acid deposition provisions of the CAA.

The national Acid Rain Program NO_x emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. All of OTP's generating facilities met the NO_x standards during 2016.

The Cross-State Air Pollution Rule (CSAPR) requires SO_2 and NO_x emission reductions in primarily eastern states in order to allow downwind states to achieve national ambient air quality standards (NAAQS). CSAPR's Phase 1 emission budgets began on January 1, 2015 for the annual SO_2 and NO_x programs, with stricter Phase 2 budgets beginning in 2017.

The CSAPR rule applies to OTP's Solway gas peaking plant and the Hoot Lake coal-fired plant in Minnesota. Hoot Lake Plant may be required to purchase SO_2 allowances to continue operating at historical levels. Minnesota is considered a Group 2 state for SO_2 compliance. Any SO_2 allowances that need to be obtained for Hoot Lake Plant will need to be from an entity in a Group 2 state. However, due to reduced dispatch of Hoot Lake Plant in 2016 and early 2017 due to power market conditions, and a decline in Group 2 SO_2 allowance prices throughout 2016, the impact of the CSAPR rule is anticipated to be minimal.

On September 7, 2016 the EPA finalized an update to the CSAPR to address interstate emission transport with respect to the more recent 2008 ozone NAAQS. The updated CSAPR does not apply to Minnesota, North Dakota and South Dakota.

On October 1, 2015 the EPA announced that it tightened the primary and secondary NAAQS for ozone from 75 parts per billion (ppb) to 70 ppb. This was at the upper end of the range of which the EPA had proposed, which was 65 to 70 ppb. As set forth in the rule, EPA requested that states submit their initial ozone designation recommendations no later than October 1, 2016. All of the states in which OTP operates recommended that they be designated as attainment. EPA will review these recommendations, along with 2014-2016 air quality data, to make final determinations of whether areas are in attainment with the new standard by October 1, 2017. Nonattainment areas are required to meet the standard in the 2020 to 2037 timeframe, with deadlines depending on the severity of an area's ozone problem. Several parties filed petitions for review in the D.C. Circuit challenging the rule and litigation is now pending.

In June 2010, the EPA established a new primary NAAQS for SO_2 at a level of 75 ppb on a 1-hour average. Designations for this standard are proceeding under several different pathways. For certain large sources as defined by 2012 emissions, including Big Stone Plant and Coyote Station, the EPA entered into a consent decree with the Sierra Club/Natural Resources Defense Council that required the EPA to promulgate final designations near those sources by July 2, 2016. On June 30, 2016, the EPA signed a final rule that designated the areas around Big Stone Plant and Coyote Station as being in attainment/unclassifiable with the 1-hour SO_2 NAAQS. Numerous other sources, including Hoot Lake Plant, are covered by the EPA's final Data Requirements Rule (DRR) that was finalized in August 2015. The DRR requires states to provide either modeling or monitoring data to adequately characterize SO_2 emissions surrounding those sources. Based on modeling, in January 2017, the state of Minnesota recommended to the EPA that the area surrounding Hoot Lake Plant be designated as attainment. The EPA will evaluate the state submittals, and it is anticipated that the EPA will issue final designations for the DRR by the end of 2017.

Air Quality—Hazardous Air Pollutants—On December 16, 2011 the EPA signed a final rule to reduce mercury and other air toxics emissions from power plants known as the MATS rule. The final rule became effective on April 16, 2012, and plants had until April 16, 2015 to comply. However, the EPA encouraged state permitting authorities to broadly grant a one-year compliance extension to plants that need additional time to install controls. With the installation of new pollution control equipment in 2015, OTP's affected units are meeting current requirements. Emissions monitoring equipment and/or stack testing is being used to verify compliance with the standards. Litigation surrounding the MATS rule is ongoing despite the expiration of the compliance deadlines, and the rule remains in effect while the litigation continues. On April 15, 2016 the EPA issued a supplemental finding that the MATS rule continues to be "appropriate and necessary" when considering the costs of compliance. This finding is being challenged by several parties.

Air Quality—EPA New Source Review Enforcement Initiative—In 1998 the EPA announced its New Source Review Enforcement Initiative targeting coal-fired power plants, petroleum refineries, pulp and paper mills and other industries for alleged violations of the EPA's New Source Review rules. These rules require owners or operators that construct new major sources or make major modifications to existing sources to obtain permits and install air pollution control equipment at affected facilities. Pursuant to the Initiative, the EPA has attempted to determine if emission sources violated certain provisions of the CAA by making major modifications to their facilities without installing state-of-the-art pollution controls. OTP has not received any recent requests from the EPA, pursuant to Section 114(a) of the CAA, to provide information relative to past operation and capital construction projects at its coal-fired plants.

Air Quality—Regional Haze Program—The EPA promulgated the Regional Haze Rule in 1999, and on June 15, 2005 the EPA provided final guidelines for conducting Best-Available Retrofit Technology (BART) determinations under the rule. The Regional Haze Rule requires emissions reductions from BART-eligible sources that are deemed to contribute to visibility impairment in Class I air quality areas. Big Stone Plant is BART eligible, and the South Dakota DENR determined that the plant is subject to emission reduction requirements based on the modeled contribution of the plant emissions to visibility impairment in downwind Class I air quality areas. Based on the South Dakota DENR's BART determination and the final South Dakota Regional Haze State Implementation Plan (SIP) approved by the EPA on March 29, 2012, Big Stone Plant was required to install Selective Catalytic Reduction and separated over-fire air to reduce NO_x emissions, dry flue gas desulfurization to reduce SO_2 emissions, and a new baghouse for particulate matter control. The Big Stone Plant BART compliant AQCS equipment was placed into commercial operation on December 29, 2015.

The North Dakota Regional Haze SIP requires that Coyote Station reduce its NO_x emissions to 0.5 pounds per million Btu as calculated on a 30-day rolling average basis beginning on July 1, 2018. The control equipment was installed during a spring 2016 outage, and tuning of the equipment is ongoing.

Air Quality—Greenhouse Gas (GHG) Regulation—Combustion of fossil fuels for the generation of electricity is a considerable stationary source of CO_2 emissions in the United States and globally. OTP is an owner or part-owner of three baseload, coal-fired electricity generating plants and three fuel-oil or natural gas-fired combustion turbine peaking plants with a combined net dependable capacity of 650 MW. In 2016 these plants emitted approximately 2.7 million tons of CO_2.

In April 2007, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate CO_2 and other GHGs from automobiles as "air pollutants" under the CAA. The EPA thereafter conducted a rulemaking to determine whether GHG emissions contribute to climate change "which may reasonably be anticipated to endanger public health or welfare." While this case addressed a provision of the CAA related to emissions from motor vehicles, a parallel provision of the CAA applies to stationary sources such as electric generators. The EPA determined that parallel provision would be automatically triggered once the EPA began regulating motor vehicle GHG emissions. The first step in the EPA rulemaking process was the publication of an endangerment finding in the December 15, 2009 Federal Register where the EPA found that CO_2 and five other GHGs—methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride—threaten public health and the environment.

The EPA's endangerment finding for GHGs did not in and of itself impose any emission reduction requirements but rather authorized the EPA to finalize the GHG standards for new light-duty vehicles as part of the joint rulemaking with the Department of Transportation. These standards applied to motor vehicles as of January 2011, which the EPA determined made GHGs "subject to regulation" under the CAA. According to the EPA, this triggered the Prevention of Significant Deterioration (PSD) and Title V operating permits programs for stationary sources of GHGs.

On June 6, 2010 the EPA published a final "tailoring rule" that phased in application of its PSD and Title V programs to GHG emission sources, including power plants. The PSD program applies to existing sources if there is a physical change or change in the method of operation of the facility that results in a significant net emissions increase of any pollutant. As a result, PSD does not apply on a set timeline as is the case with other regulatory programs, but is triggered when certain activities take place at a major source. If triggered, the owner or operator of an affected facility must undergo a review which requires, among other things, the identification and implementation of best-available control technology (BACT) for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

In June 2012 the United States Court of Appeals for the D.C. Circuit upheld most of the EPA's rules regarding the regulation of GHGs under the CAA, including the tailoring rule. However, in October 2013 the U.S. Supreme Court granted a petition for a writ of certiorari to review the question of whether the regulation of new motor vehicle GHG emissions does in fact automatically trigger PSD and Title V regulation of GHGs for stationary sources. On June 23, 2014 the U.S. Supreme Court issued its decision that, in summary, held the EPA exceeded its statutory authority and may not require a PSD or Title V permit based solely on GHG emissions. However, the U.S. Supreme Court also said the EPA could continue to require that PSD permits for sources otherwise subject to PSD based on emissions of conventional pollutants contain limitations on GHG emissions based on the application of BACT. The EPA revised its regulations to implement this ruling and in 2016 proposed a *de minimis* level of GHG emissions below which PSD would not apply. OTP does not anticipate making modifications that would trigger PSD requirements at any of its facilities or undertaking construction of a new unit that might trigger PSD.

The EPA has developed New Source Performance Standards (NSPS) for GHGs from new and existing fossil fuel-fired electric generating units. On October 23, 2015 the EPA published the final NSPS under section 111(b) of the CAA that requires certain new units (as well as modified and reconstructed units) to meet CO_2 emission standards. New natural gas combustion turbines are required to meet a standard of 1,000 lbs. of CO_2 per gross megawatt hour averaged over a 12-month period if they meet the definition of a baseload unit. New natural gas combined cycle units are anticipated to fit into this category. Simple cycle combustion turbines are regulated in a non-baseload category that is required to meet a heat input based standard that can be met by burning clean fuels such as natural gas. This rule was challenged by a number of parties and litigation is pending.

The EPA also published GHG performance standards for existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike those set under CAA Section 111(b), applies to existing sources of a pollutant. Under Section 111(d), the EPA promulgates emission guidelines and the states are then given a period of time to develop plans to implement the standard. The EPA reviews each state-developed standard and then approves it if the state's plan comports with the federal emission guidelines. If the state does not submit a plan or the EPA finds that the plan is inadequate, the EPA will prescribe a plan for that state.

For both new and existing sources, the EPA must develop a "standard of performance," which is defined as:

> *...a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated.*

For existing sources, Section 111(d) also requires the EPA to consider, "among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."

On June 18, 2014 the EPA published proposed Section 111(d) emission guidelines for existing fossil fuel-fired power plants, termed the Clean Power Plan (CPP). The CPP proposed state-specific rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the goals. An interim goal was proposed to be achieved on average over the ten year period of 2020-2029, and a final goal in 2030 and each year thereafter. The EPA used a formula that relies on four building blocks to determine the state-specific goal: (1) a six percent heat rate improvement at each coal plant, (2) increased reliance on natural gas combined cycle units, (3) a renewable energy target, and (4) demand side energy efficiency savings. Specific to OTP, EPA's proposed formula created substantially different targets for

North Dakota, South Dakota, and Minnesota, primarily due to the EPA's second building block that envisioned redispatching natural gas combined cycle units to a 70% capacity factor.

On October 23, 2015 the EPA published the final CPP. The final rule delayed the start of the interim goal period to 2022 and used a different formula to calculate state goals that resulted in a narrower range of state-specific targets. The EPA formula relied on only three building blocks in the final rule: (1) a heat rate improvement at each coal plant, (2) increased reliance on natural gas combined cycle units, and (3) increased deployment of renewable energy. These building blocks were applied to each grid interconnection that resulted in final national uniform emission rate standards of 1,305 pounds of CO_2 per net megawatt hour for coal plants and 771 pounds of CO_2 per net megawatt hour for natural gas combined cycle plants. These uniform rates were applied on a weighted average basis to the affected units of each state, resulting in a much narrower range of goals in the final rule as compared to the proposed rule. The EPA then translated the rate goals into mass-based goals that can be applied to existing sources or, if a state chooses, a mass-based goal that applies to both existing sources and new sources.

A number of states, utilities, and trade groups filed petitions for review with the D.C. Circuit seeking to overturn the rule, and also moved to stay the rule. On January 14, 2016 the D.C. Circuit denied the stay motions. Numerous petitioners then sought an emergency stay in the U.S. Supreme Court. On February 9, 2016 the U.S. Supreme Court granted a stay of the rule pending disposition of petitions for review in the D.C. Circuit and, if a petition for a writ of certiorari seeking review by the U.S. Supreme Court were granted, any final Supreme Court determination. The D.C. Circuit heard oral argument on challenges to the CO_2 emission guidelines on September 27, 2016 before the full court, and a decision is likely to be rendered in the first half of 2017. In addition, members of Congress and the new administration have been very critical of the CPP and may take actions that could impact the rule or the litigation. Therefore, while the CPP remains stayed, there is uncertainty regarding the future of the rule.

Also on October 23, 2015 the EPA proposed model trading rules along with the proposed federal plan for states that do not have a fully approved state plan. The EPA proposed both a rate-based trading plan and a mass-based trading plan for the federal plan. On December 19, 2016 the EPA withdrew the model trading rules and federal plan from the interagency review process and instead released the model trading rules as a working draft. The draft does not reflect final agency action or official statement of policy, and does not create any legal obligations. The docket for these items will remain open so that the EPA can potentially finalize the work in the future should the CPP, or a similar rule, be implemented.

Several states and regional organizations have or will develop state-specific or regional legislative initiatives to reduce GHG emissions through mandatory programs. In 2007 the state of Minnesota passed legislation regarding renewable energy portfolio standards that requires retail electricity providers to obtain 25% of the electric energy sold to Minnesota customers from renewable sources by the year 2025. Additionally, in 2013 the state of Minnesota passed a provision that requires public utilities to generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5% of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy. The Minnesota legislature set a January 1, 2008 deadline for the MPUC to establish an estimate of the likely range of costs of future CO_2 regulation on electricity generation. The legislation also set state targets for reducing fossil fuel use, included goals for reducing the state's output of GHGs, and restricted importing electricity that would contribute to statewide power sector CO_2 emission. The MPUC, in its order dated December 21, 2007, established an estimate of future CO_2 regulation costs at between $4/ton and $30/ton emitted in 2012 and after. Annual updates of the range are required. For 2016 the range is $9-$34/ton, and the applicable effective date to begin using CO_2 costs in resource planning decisions is 2022. Minnesota opened a new docket to investigate the environmental and socioeconomic costs of externalities associated with electricity generation. A final ruling in that case is not expected until the second quarter of 2017.

The states of North Dakota and South Dakota currently have no proposed or pending legislation related to the regulation of GHG emissions, but North Dakota and South Dakota have 10% renewable energy objectives. OTP currently has sufficient renewable generation to meet the renewable energy objectives in both North Dakota and South Dakota.

While the eventual outcome of GHG regulation is unknown, OTP is taking steps to reduce its carbon footprint and mitigate levels of CO_2 emitted in the process of generating electricity for its customers through the following initiatives:

- Supply efficiency and reliability: Since 2005, SO_2 and NO_x emitted from OTP's fossil fuel-fired plants have decreased 50% and 62%, respectively. OTP's efforts to increase plant efficiency and add renewable energy to its resource mix have reduced its CO_2 intensity. Between 2005 and 2015 OTP decreased its overall system average CO_2 emissions intensity by approximately 30%. With recent installations of pollution control equipment, OTP expects to achieve reductions of mercury emissions of more than 70% between 2005 and 2016. Further reductions are expected with the anticipated replacement of Hoot Lake Plant generation with natural gas-fired generation in the 2021 timeframe.
- Conservation: Since 1992 OTP has helped its customers conserve more than 3.1 million cumulative megawatt-hours of electricity, which is roughly equivalent to the amount of electricity that 258,000 average homes would use in a year and represents approximately 250% of the annual energy sales of OTP's entire residential customer base. Additionally, OTP's conservation programs contribute 71 MW of load reduction to its system.
- Renewable energy: Since 2002, OTP's customers have been able to purchase 100% of their electricity from wind generation through OTP's Tail Winds program. OTP has access to 102.9 MW of wind powered generation under power purchase agreements and owns 138 MW of wind powered generation. OTP is exploring options for meeting a Minnesota legislative mandate requiring Minnesota's investor-owned utilities to serve 1.5% of their Minnesota retail electric sales with solar power by 2020.
- Other: OTP is a participating member of the EPA's sulfur hexafluoride (SF_6) Emission Reduction Partnership for Electric Power Systems program, which proactively is targeting a reduction in emissions of SF_6, a potent GHG. SF_6 has a global-warming potential 23,900 times that of CO_2. OTP participates in carbon sequestration research through the Plains CO_2 Reduction (PCOR) Partnership through the University of North Dakota's Energy and Environmental Research Center. The PCOR Partnership is a collaborative effort of approximately 100 public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic CO_2 emissions from stationary sources in central North America.

While the future financial impact of any proposed or pending litigation or regulation of GHG emissions is unknown at this time, any capital and operating costs incurred for additional pollution control equipment or CO_2 emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset credits, or the imposition of a carbon tax or cap and trade program at the state or federal level could materially adversely affect the Company's future results of operations, cash flows, and possibly financial condition, unless such costs could be recovered through regulated rates and/or future market prices for energy.

Water Quality—The Federal Water Pollution Control Act Amendments of 1972 and amendments thereto, provide for, among other things, the

imposition of effluent limitations to regulate discharges of pollutants, including thermal discharges, into the waters of the United States, and the EPA has established effluent guidelines for the steam electric power generating industry. Discharges must also comply with state water quality standards.

Effluent limits specific to Hoot Lake Plant and Coyote Station are incorporated into their National Pollutant Discharge Elimination System (NPDES) permits. Big Stone Plant is a zero discharge facility and therefore does not have a NPDES permit. On November 3, 2015 the EPA published the final rule that sets technology-based effluent limitations on certain types of discharges. Generally, the final rule establishes new requirements for wastewater streams from wet flue gas desulfurization, fly ash transport, and bottom ash transport. This includes zero discharge requirements for fly ash and bottom ash transport water. OTP's facilities either utilize dry ash handling or use transport water in a closed loop manner. Therefore, OTP anticipates minimal impact from the rule.

On May 9, 2014 the EPA Administrator signed a final rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. The final rule includes seven compliance options, plus a potential *"de minimis"* option that is not well defined. Although the impact of the Hoot Lake Plant intake structure has been extensively evaluated in two separate studies both of which showed minimal impact, OTP will need to have state agency discussions during the renewal of the Hoot Lake Plant NPDES permit to determine the appropriate path forward. Coyote Station will also need to provide various studies with their next NPDES permit renewal application, but minimal impact is anticipated since Coyote Station already uses closed-cycle cooling. Litigation over the final rule remains pending.

OTP has all federal and state water permits presently necessary for the operation of the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

OTP owns five small dams on the Otter Tail River, which are subject to FERC licensing requirements. A license for all five dams was issued on December 5, 1991. In June 2015 OTP notified the FERC of its intent to relicense these dams. The current FERC license expires in 2021 and the licensing process takes approximately 5 years. The FERC completed the scoping meeting in the fall of 2016. OTP is currently in the process of finalizing the study plan. The studies will be completed in 2017 and 2018. These studies will be followed by the filing of the license application in 2019. OTP expects FERC to issue an order on the license application in 2021. Total nameplate rating (manufacturer's expected output) of the five dams is 3,450 kW.

Solid Waste—Permits for disposal of ash and other solid wastes have been issued for the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

On December 19, 2014 the EPA announced a final rule regulating coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA) regulating the disposal of coal ash generated from the combustion of coal by electric utilities under Subtitle D's nonhazardous provisions. The final rule was published on April 17, 2015. The rule requires OTP to complete certain actions, such as installing additional groundwater monitoring wells and investigating whether existing surface impoundments meet defined location restrictions, in order to determine whether existing surface impoundments should be retired or retrofitted with liners. OTP is still in the process of completing its actions. Therefore, the cost impact of this rule will not be known until those actions are completed. Existing landfill cells can continue to operate as designed, but future expansions will require composite liner and leachate collection systems. On December 20, 2016 the Water Infrastructure Improvements for the Nation (WIIN) Act was signed into law. The WIIN Act allows states to regulate CCR if the state standards are at least as protective as the EPA CCR Rule.

At the request of the Minnesota Pollution Control Agency (MPCA), OTP has an ongoing investigation at its former, closed Hoot Lake Plant ash disposal sites. The MPCA continues to monitor site activities under its Voluntary Investigation and Cleanup (VIC) Program. OTP completed projects in 2014 and 2015 that removed the ash from two entire VIC areas and placed it in OTP's permitted disposal area. Efforts to remove ash from the remaining two VIC areas began in 2016 and will continue through 2017.

In 1980 the United States enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly known as CERCLA or the Federal Superfund law, which was reauthorized and amended in 1986. In 1983 Minnesota adopted the Minnesota Environmental Response and Liability Act, commonly known as the Minnesota Superfund law. In 1988 South Dakota enacted the Regulated Substance Discharges Act, commonly known as the South Dakota Superfund law. In 1989, North Dakota enacted the Environmental Emergency Cost Recovery Act. Among other requirements, the federal and state acts establish environmental response funds to pay for remedial actions associated with the release or threatened release of certain regulated substances into the environment. These federal and state Superfund laws also establish liability for cleanup costs and damage to the environment resulting from such release or threatened release of regulated substances. The Minnesota Superfund law also creates liability for personal injury and economic loss under certain circumstances. OTP has not incurred any significant costs to date related to these laws. OTP is not presently named as a potentially responsible party under the federal or state Superfund laws.

CAPITAL EXPENDITURES

OTP is continually expanding, replacing and improving its electric facilities. During 2016 approximately $150 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2016 gross electric property additions, including construction work in progress, were approximately $677 million and gross retirements were approximately $89 million. OTP estimates that during the five-year period 2017-2021 it will invest approximately $862 million for electric construction, which includes $315 million for renewable wind and solar energy generation projects, $147 million for natural gas-fired generation to replace Hoot Lake Plant capacity and $116 million for MVP transmission projects. The remainder of the 2017-2021 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements" section for further discussion.

The $315 million planned investment for renewable wind and solar energy generation projects includes the Merricourt Wind Project. In November 2016 OTP signed agreements to purchase this 150-MW wind farm in southeastern North Dakota that EDF Renewable Energy will design and build in 2019.

FRANCHISES

At December 31, 2016 OTP had franchises to operate as an electric utility in substantially all of the incorporated municipalities it serves. All franchises are nonexclusive and generally were obtained for 20-year terms, with varying expiration dates. No franchises are required to serve unincorporated communities in any of the three states that OTP serves. OTP believes that its franchises will be renewed prior to expiration.

EMPLOYEES

At December 31, 2016 OTP had 682 equivalent full-time employees. A total of 397 OTP employees are represented by local unions of the International Brotherhood of Electrical Workers under two separate contracts expiring on August 21, 2017 and October 31, 2017. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

MANUFACTURING

GENERAL

Manufacturing consists of businesses engaged in the following activities: contract machining, metal parts stamping, fabrication and painting, and production of material handling trays and horticultural containers.

The Company derived 28%, 28% and 27% of its consolidated operating revenues and 11%, 9% and 17% of its consolidated operating income from the Manufacturing segment for the years ended December 31, 2016, 2015 and 2014, respectively. Following is a brief description of each of these businesses:

BTD Manufacturing, Inc. (BTD), with headquarters located in Detroit Lakes, Minnesota, is a metal stamping and tool and die manufacturer that provides its services mainly to customers in the Midwest. BTD stamps, fabricates, welds, paints and laser cuts metal components according to manufacturers' specifications primarily for the recreational vehicle, agricultural, oil and gas, lawn and garden, industrial equipment, health and fitness and enclosure industries in its facilities in Detroit Lakes and Lakeville, Minnesota, Washington, Illinois and Dawsonville, Georgia. BTD's Illinois facility also manufactures and fabricates parts for off-road equipment, mining machinery, oil fields and offshore oil rigs, wind industry components, broadcast antennae and farm equipment.

On September 1, 2015 Miller Welding and Iron Works, Inc., a wholly owned subsidiary of BTD, acquired the assets of Impulse for $30.8 million in cash. A post-closing reduction in the purchase price of $1.5 million was agreed to in June 2016 resulting in an adjusted purchase price of $29.3 million. Impulse now operates under the name BTD-Georgia. BTD-Georgia offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers.

T.O. Plastics, Inc. (T.O. Plastics), located in Otsego and Clearwater, Minnesota, manufactures and sells thermoformed products for the horticulture industry throughout the United States. T.O. Plastics also designs and manufactures quality thermoformed products and packaging solutions for the medical and life sciences, industrial, recreation and electronics industries. Examples of products produced for these industries are clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts. T.O. Plastics' Otsego thermoforming facility has an AIB International compliance rating for producing food-contact packaging materials in its operations.

PRODUCT DISTRIBUTION

The principal method for distribution of the manufacturing companies' products is by direct shipment to the customer by common carrier ground transportation. No single customer or product of the Company's manufacturing companies account for over 10% of the Company's consolidated revenue.

COMPETITION

The various markets in which the Manufacturing segment entities compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources, excess capacity, labor advantages and larger marketing, research and development staffs and facilities than the Company's manufacturing entities.

The Company believes the principal competitive factors in its Manufacturing segment are product performance, quality, price, technical innovation, cost effectiveness, customer service and breadth of product line. The Company's manufacturing entities intend to continue to compete on the basis of high-performance products, innovative production technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

RAW MATERIALS SUPPLY

The companies in the Manufacturing segment use raw materials in the products they manufacture, including steel, aluminum and polystyrene and other plastics resins. Both pricing increases and availability of these raw materials are concerns of companies in the Manufacturing segment. The companies in the Manufacturing segment attempt to pass increases in the costs of these raw materials on to their customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins in the Manufacturing segment. Additionally, a certain amount of residual material (scrap) is a by-product of many of the manufacturing and production processes used by the Company's manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of the Company's manufacturing companies as it reduces their ability to mitigate the cost associated with excess material.

BACKLOG

The Manufacturing segment has backlog in place to support 2017 revenues of approximately $118 million compared with $134 million one year ago.

CAPITAL EXPENDITURES

Capital expenditures in the Manufacturing segment typically include additional investments in new manufacturing equipment or expenditures to replace worn-out manufacturing equipment. Capital expenditures may also be made for the purchase of land and buildings for plant expansion and for investments in management information systems. During 2016, cash expenditures for capital additions in the Manufacturing segment were approximately $8 million. Total capital expenditures for the Manufacturing segment during the five-year period 2017-2021 are estimated to be approximately $54 million.

EMPLOYEES

At December 31, 2016 the Manufacturing segment had 1,175 full-time employees. There were 1,037 full-time employees at BTD and its subsidiaries and 138 full-time employees at T.O. Plastics as of December 31, 2016.

PLASTICS

GENERAL

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The Company derived 19%, 20% and 22% of its consolidated operating revenues and 16%, 19% and 20% of its consolidated operating income from the Plastics segment for the years ended December 31, 2016, 2015 and 2014, respectively. 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, northwestern and south-central regions of the United States.

Together these companies have the current capacity to produce approximately 300 million pounds of PVC pipe annually.

CUSTOMERS

PVC pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for the PVC pipe products consist primarily of wholesalers and distributors throughout the northern, midwestern, south-central, western and northwest United States. The principal method for distribution of the PVC pipe companies' products is by common carrier ground transportation. No single customer of the PVC pipe companies accounts for over 10% of the Company's consolidated revenue.

COMPETITION

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

Northern Pipe and Vinyltech intend to continue to compete on the basis of their high quality products, cost-effective production techniques and close customer relations and support.

MANUFACTURING AND RESIN SUPPLY

PVC pipe is manufactured through a process known as extrusion. During the production process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is then pulled through a series of water cooling tanks, marked to identify the type of pipe and cut to finished lengths. Warehouse and outdoor storage facilities are used to store the finished product. Inventory is shipped from storage to distributors and customers by common carrier.

The PVC resins are acquired in bulk and shipped to point of use by rail car. There are four vendors that Northern Pipe and Vinyltech can source to supply their PVC resin requirements. Two vendors provided 100% and 96% of total resin purchases in 2016 and 2015, respectively. The supply of PVC resin may also be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which is subject to risk of damage to the plants and potential shutdown of resin production because of exposure to hurricanes that occur in that 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 the Plastics segment to manufacture products, cause customers to cancel orders or require incurrence of additional expenses to obtain PVC resin from alternative sources, if such sources were available. Both Northern Pipe and Vinyltech believe they have good relationships with their key raw material vendors.

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

CAPITAL EXPENDITURES

Capital expenditures in the Plastics segment typically include investments in extrusion machines and support equipment. During 2016, cash expenditures for capital additions in the Plastics segment were approximately $3 million. Total capital expenditures for the five-year period 2017-2021 are estimated to be approximately $20 million to replace existing equipment.

EMPLOYEES

At December 31, 2016 the Plastics segment had 156 full-time employees. Northern Pipe had 90 full-time employees and Vinyltech had 66 full-time employees as of December 31, 2016.

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 Annual Report on Form 10-K or in our other SEC filings could materially adversely affect our business, financial condition and results of operations.

GENERAL

Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.
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 requires 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.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. 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 results of operations.

Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and increase borrowing costs and pension plan and postretirement health care expenses.
We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are unable to access capital at competitive rates, our ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more financial markets.

Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of customers to finance purchases of goods and services, and our financial condition, as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.

Changes in the U.S. capital markets could also have significant effects on our pension plan. Our pension income or expense is affected by factors including the market performance of the assets in the master pension trust maintained for the pension plan for some of our employees, the weighted average asset allocation and long-term rate of return of our pension plan assets, the discount rate used to determine the service and interest cost components of our net periodic pension cost and assumed rates of increase in our employees' future compensation. If our pension plan assets do not achieve positive rates of return, or if our estimates and assumed rates are not accurate, our earnings may decrease because net periodic pension costs would rise and we could be required to provide additional funds to cover our obligations to employees under the pension plan.

We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

Any significant impairment of our goodwill would cause a decrease in our asset values and a reduction in our net operating income.
We had approximately $37.6 million of goodwill recorded on our consolidated balance sheet as of December 31, 2016. We have recorded goodwill for businesses in our Manufacturing and Plastics business segments. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net operating performance. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying amount of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Any changes in key assumptions or actual performance compared with key assumptions about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge. Declines in projected operating cash flows at BTD or the Plastics segment may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and debt covenants and pay dividends to our shareholders could have an adverse effect on the Company.
Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the actual and projected earnings, cash flows, capital requirements and general financial position of our subsidiary companies, as well as regulatory factors, financial covenants, general business conditions and other matters.

Under our $130 million revolving credit agreement we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00. OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 under its $170 million revolving credit agreement. Both credit agreements contain restrictions on the payment of cash dividends on a default or event of default. As of December 31, 2016 we were in compliance with the debt 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 or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. The MPUC indirectly limits the amount of dividends OTP can pay to us by requiring an equity-to-total-capitalization ratio between 47.5% and 58.1% based on OTP's 2016 capital structure petition. OTP's equity-to-total-capitalization ratio, including short-term debt, was 52.9% as of December 31, 2016.

While these restrictions are not expected to affect our ability to pay dividends at the current level in the foreseeable future, there is no assurance that adverse financial results would not reduce or eliminate our ability to pay dividends.

We rely on our information systems to conduct our business, and failure to protect these systems against security breaches or cyber-attacks could adversely affect our business and results of operations. Additionally, if these systems fail or become unavailable for any significant period of time, our business could be harmed.
All of our businesses require us to collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss. We also use third-party vendors to electronically process certain of our business transactions. The efficient operation of our business is dependent on computer hardware and software systems. Information systems, both ours and those of third-party information processors, are vulnerable to security breach by computer hackers and cyber terrorists.

The breach of certain business systems could affect our ability to correctly record, process and report financial information and transactions. 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. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. We have cybersecurity insurance related to a breach event covering expenses for notification, credit monitoring, investigation, crisis management, public relations and legal advice. The policy also provides coverage for regulatory action defense including fines and penalties, potential payment card industry fines and penalties and costs related to cyber extortion. We also maintain property and casualty insurance that may cover restoration of data, certain physical damage or third party injuries caused by potential cybersecurity incidents. However, damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available.

We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information maintained on our information systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls designed to protect and preserve the confidentiality, integrity and availability of data and systems. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks. In addition, the unavailability of the information systems or failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance and increased overhead costs, causing our business and results of operations to suffer. 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 results of operations.

Economic conditions could negatively impact our businesses.
Our businesses are affected by local, national and worldwide economic conditions. Tightening of credit in financial markets could adversely affect the ability of customers to finance purchases of our goods and services, resulting in decreased orders, cancelled or deferred orders, slower payment cycles, and increased bad debt and customer bankruptcies. Our businesses may also be adversely affected by decreases in the general level of economic activity, such as decreases in business and consumer spending. A decline in the level of economic activity and uncertainty regarding energy and commodity prices could adversely affect our results of operations and our future growth.

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 investment 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 revenue growth targets, which, together with any resulting impact on our net income growth, may adversely affect the market price of our common shares.

Our plans to grow and realign our business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.
As part of our business strategy, we intend to increase capital expenditures in our existing businesses and to continually assess our mix of businesses and potential strategic acquisitions or dispositions. There are risks associated with capital expenditures including not being granted timely or full recovery of rate base additions in our regulated utility business and the inability to recover the cost of capital additions due to an economic downturn, lack of markets for new products, competition from producers of lower cost or alternative products, product defects, loss of customers or other factors. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. Future acquisitions could involve numerous risks including: difficulties in integrating the operations, services, products and personnel of the acquired business; and the potential loss of key employees, customers and suppliers of the acquired business. If we are unable to successfully manage these risks, we could face reductions in net income in future periods.

We may, from time to time, sell assets to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any assets sold and other potential liabilities. The sale of any of our businesses also exposes us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.
As part of our business strategy, we continually assess our business portfolio to determine if our operating companies continue to meet our portfolio criteria. A loss on the sale of a business would be recognized if a company is sold for less than its book value.

In certain transactions we retain obligations that have arisen, or subsequently arise, out of our conduct of the business prior to the sale. These obligations are sometimes direct or, in other cases, take the form of an indemnification obligation to the buyer. These obligations include such things as warranty, environmental, and the collection of certain receivables. Unforeseen costs related to these obligations could result in future losses related to the business sold.

Significant warranty claims and remediation costs in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition.
Depending on the specific product or service, we may provide certain warranty terms against manufacturing defects and certain materials. We reserve for warranty claims based on industry experience and estimates made by management. For some of our products we have limited history on which to base our warranty estimate. Our assumptions could be materially different from any actual claim and could exceed reserve balances.

Expenses associated with the remediation of warranty claims for our manufacturing businesses, including our former wind tower manufacturer, could be substantial. The potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. If we are required to cover remediation expenses in addition to our regular warranty coverage, we could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect our consolidated net income and financial condition.

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

Changes in tax laws, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could materially adversely affect our business, financial condition, results of operations and prospects.
Our provision for income taxes and reporting of tax-related assets and liabilities require significant judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, regulations and interpretations, the financial condition and results of operations of Otter Tail Corporation, and the resolution of audit issues raised by taxing authorities. Ultimate resolution of income tax matters may result in material adjustments to tax-related assets and liabilities, which could materially adversely affect our business, financial condition, results of operations and prospects.

ELECTRIC

We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to shareholders or scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.
A number of factors, many of which are beyond our control, may contribute to fluctuations in our revenues and expenses from electric operations, causing our net income to fluctuate from period to period. These risks include fluctuations in the volume and price of sales of electricity to customers or other utilities, which may be affected by factors such as mergers and acquisitions of other utilities, geographic location of other utilities, transmission costs (including increased costs related to operations of regional transmission organizations), changes in the manner in which wholesale power is sold and purchased, unplanned interruptions at OTP's generating plants, the effects of regulation and legislation, demographic changes in OTP's customer base and changes in OTP's customer demand or load growth. Electric wholesale margins have been significantly and adversely affected by increased efficiencies in the MISO market. Other risks include weather conditions or changes in weather patterns (including severe weather that could result in damage to OTP's assets), fuel and purchased power costs and the rate of economic growth or decline in OTP's service areas. A decrease in revenues or an increase in expenses related to our electric operations may reduce the amount of funds available for our existing and future businesses, which could result in increased financing requirements, impair our ability to make expected distributions to shareholders or impair our ability to make scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.
We are subject to federal and state legislation, government regulations and regulatory actions that may have a negative impact on our business and results of operations. The electric rates that OTP is allowed to charge for its electric services are one of the most important items influencing our financial position, results of operations and liquidity. The rates that OTP charges its electric customers are subject to review and determination by state public utility commissions in Minnesota, North Dakota and South Dakota. OTP is also regulated by the FERC. Our ability to obtain rate adjustments to maintain reasonable rates of return depends on regulatory action under applicable statutes and regulations and we cannot provide assurance that rate adjustments will be obtained or reasonable authorized rates of return on capital will be earned. OTP will file rate cases with, or seek cost recovery authorization from, federal and state regulatory authorities. An adverse decision by one or more regulatory commissions concerning the level or method of determining electric utility rates, the authorized returns on equity, implementation of enforceable federal reliability standards or other regulatory matters, permitted business activities (such as ownership or operation of nonelectric businesses) or any prolonged delay in rendering a decision in a rate or other proceeding (including with respect to the recovery of capital expenditures in rates) could result in lower revenues and net income.

OTP's operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may 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 law and regulatory agencies, including FERC and NERC. We could be subject to potential financial penalties for compliance violations. In addition, energy policy initiatives at the state or federal level could increase incentives for distributed generation or municipal utility ownership, or local initiatives could introduce generation or distribution requirements, that could change the current integrated utility model. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. If a serious reliability incident did 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; 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 results of operations.

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

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

OTP is subject to mandatory cybersecurity and physical security regulatory requirements. OTP implements the NERC standards for operating its transmission and generation assets and stays abreast of best practices within 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 designed to protect and preserve the confidentiality, integrity and availability of data and systems. We also take prudent and reasonable steps to protect the physical security of our generation and transmission facilities. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks. 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 results of operations.

OTP's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.
Operation of electric generating facilities involves risks which can adversely affect energy output and efficiency levels. Most of OTP's generating capacity is coal-fired. OTP relies on a limited number of suppliers of coal, making it vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. OTP is a captive rail shipper of the BNSF Railway for shipments of coal to its Big Stone and Hoot Lake plants, making it vulnerable to increased prices for coal transportation from a sole supplier and disruptions in coal deliveries due to rail line congestion and constraints on the rail lines between the coal source mines and the plants. Higher fuel prices result in higher electric rates for OTP's retail customers through fuel clause adjustments and could make it less competitive in wholesale electric markets. Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error and catastrophic events such as fires, explosions, floods, intentional acts of destruction or other similar occurrences affecting OTP's electric generating facilities. The loss of a major generating facility would require OTP to find other sources of supply, if available, and expose it to higher purchased power costs.

Changes to regulation of generating plant emissions, including but not limited to CO_2 emissions, could affect our operating costs and the costs of supplying electricity to our customers.
Existing or new laws or regulations passed or issued by federal or state authorities addressing climate change or reductions of GHG emissions, such as mandated levels of renewable generation, mandatory reductions in CO_2 emission levels, taxes on CO_2 emissions or cap and trade regimes, could require us to incur significant new costs, which could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where OTP provides service or through increased market prices for electricity. Debate continues in Congress and in the new administration on the direction and scope of U.S. and international policy on climate change and regulation of GHGs. Congress has considered but has not adopted GHG legislation which would require a reduction in GHG emissions and there is no legislation under active

consideration at this time. The likelihood of any federal mandatory CO_2 emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, are uncertain, as are the future of additional regulatory actions.

In 2014, the EPA published proposed standards of performance for CO_2 emissions from new fossil fuel-fired power plants, proposed CO_2 emission guidelines for existing fossil fuel-fired power plants and proposed CO_2 standards of performance for CO_2 emissions from reconstructed and modified fossil fuel-fired power plants, essentially requiring that such plants install updated control technology when constructing, modifying or reconstructing to reduce their emissions. The EPA published final rules for each of these proposals on October 23, 2015. On February 9, 2016 the U.S. Supreme Court granted a stay of the CO_2 emission guidelines for existing fossil fuel-fired power plants pending disposition of petitions for review in the D.C. Circuit and, if a petition for a writ of certiorari seeking review by the U.S. Supreme Court were granted, any final Supreme Court determination. The D.C. Circuit heard oral argument on challenges to the CO_2 emission guidelines on September 27, 2016 before the full court, and a decision will likely be rendered in early 2017. In addition, members of Congress and the new administration have been very critical of the emissions guidelines and may take actions that could impact the guidelines or related litigation. Consequently, uncertainty regarding the status of the rules may continue for a period of time. OTP is assessing the potential impact of the EPA's final rules on existing affected sources of CO_2 emissions at OTP. The final outcome of this rulemaking process could have a material adverse impact on our business and financial results.

MANUFACTURING

Competition from foreign and domestic manufacturers, the price and availability of raw materials, prices and supply of scrap or recyclable material and general economic conditions could affect the revenues and earnings of our manufacturing businesses.

Our manufacturing businesses are subject to intense risks associated with competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development staffs and facilities and other capabilities that may place downward pressure on margins and profitability. The companies in our Manufacturing segment use a variety of raw materials in the products they manufacture, including steel, aluminum and polystyrene and other plastics resins. Costs for these items can fluctuate significantly. If our manufacturing businesses are not able to pass on cost increases to their customers, it could have a negative effect on profit margins in our Manufacturing segment. Additionally, a certain amount of residual material (scrap) is a by-product of many 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. Changes in macroeconomic conditions can negatively impact demand in the end-use markets for products and parts that we manufacture, resulting in reduced sales and profits.

Each of our manufacturing companies has significant customers and concentrated sales to such customers. If our relationships with significant customers should change materially, it would be difficult to immediately and profitably replace lost sales.

PLASTICS

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.

We rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors accounted for 100% of our total purchases of PVC resin in 2016 and 96% of our total purchases of PVC resin in 2015. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which may increase the risk of a shortage of resin in the event of a hurricane or other natural disaster 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 are available.

We compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.

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

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

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

By the end of 2016, certain PVC resin producers in the United States had completed approximately 900 million pounds of resin production capacity additions to support the global market for PVC resin. Should this capacity not be used to support the resin export market, vendors may take steps to have it absorbed in the U.S. resin market. If this occurs, our Plastics segment financial results could be adversely impacted by PVC resin pricing strategies implemented by U.S. producers to get this capacity absorbed in the U.S. PVC resin market.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

The Coyote Station, which commenced operation in 1981, is a 414,000 kW (nameplate rating) mine-mouth plant located in the lignite coal fields near Beulah, North Dakota and is jointly owned by OTP, Northern Municipal Power Agency, Montana-Dakota Utilities Co. and Northwestern Public Service Company. OTP is the operating agent of the Coyote Station and owns 35% of the plant.

OTP, jointly with Northwestern Public Service Company and Montana-Dakota Utilities Co., owns the 414,000 kW (nameplate rating) Big Stone Plant in northeastern South Dakota which commenced operation in 1975. OTP is the operating agent of Big Stone Plant and owns 53.9% of the plant.

Located near Fergus Falls, Minnesota, the Hoot Lake Plant is comprised of two separate generating units: a unit built in 1959 (53,500 kW nameplate rating) and a unit added in 1964 (75,000 kW nameplate rating) and modified in 1988 to provide cycling capability, allowing this unit to be more efficiently brought online from a standby mode. These two generating units have a combined nameplate rating of 128,500 kW.

Current plans are for both units to be removed from service in 2021.

OTP owns 27 wind turbines at the Langdon, North Dakota Wind Energy Center with a nameplate rating of 40,500 kW, 32 wind turbines at the Ashtabula Wind Energy Center located in Barnes County, North Dakota with a nameplate rating of 48,000 kW and 33 wind turbines at the Luverne Wind Farm located in Steele County, North Dakota with a nameplate rating of 49,500 kW.

As of December 31, 2016 OTP's transmission facilities, which are interconnected with lines of other public utilities, consisted of 535 miles of 345 kV lines; 479 miles of 230 kV lines; 878 pole miles of 115 kV lines; and 3,973 miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of 48 pole miles of the 345 kV lines, with Minnkota Power Cooperative retaining title to the original 230 kV construction, and OTP owns an undivided interest in the remaining 345 kV line miles. OTP is a joint owner, with other regional utilities, in transmission lines with the following ownership interests: 14.8% in the 70 mile Bemidji-Grand Rapids 230 kV line, approximately 14.2% of 242 pole miles of energized line in the Fargo-Monticello 345 kV project and approximately 4.8% of 255 pole miles of energized line in the Brookings to Southeast Twin Cities 345 kV project.

In addition to the properties mentioned above, all of which are utilized by the Electric segment, the Company owns and has investments in offices and service buildings utilized by each of its manufacturing and plastic pipe companies. The Company's subsidiaries own facilities and equipment used in: the manufacture of PVC pipe, thermoformed products, heavy metal fabricated products, metal parts stamping, fabricating, painting and contract machining.

Management of the Company believes the facilities and equipment described above are adequate for the Company's present businesses.

ITEM 3. Legal Proceedings

The Company is the subject of various pending or threatened legal actions and proceedings in the ordinary course of its business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. The Company records a liability in its consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where the Company has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on its consolidated financial position, results of operations or cash flows, excluding any liability for RSG charges described in Note 9 to the Company's consolidated financial statements for which an estimate cannot be made at this time.

ITEM 3A. Executive Officers of the Registrant (As of February 22, 2017)

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

Name and Age	Date Elected to Office	Present Position and Business Experience
Charles S. MacFarlane (52)	4/13/15	Present: President and Chief Executive Officer
George A. Koeck (64)	4/10/00	Present: Senior Vice President, General Counsel and Corporate Secretary
Kevin G. Moug (57)	4/9/01	Present: Chief Financial Officer and Senior Vice President
Timothy J. Rogelstad (50)	4/14/14	Present: Senior Vice President, Electric Platform
John Abbott (58)	2/11/15	Present: Senior Vice President, Manufacturing Platform

On April 13, 2015 Mr. MacFarlane was elected as the Company's President and Chief Executive Officer and as member of the Company's board of directors effective with the retirement of Edward J. McIntyre as Chief Executive Officer of the Company and as a member of the Company's board of directors. On February 5, 2014 the Company's board of directors appointed Mr. MacFarlane, then President and Chief Executive Officer of OTP and Senior Vice President, Electric Platform of the Company, to the role of President and Chief Operating Officer of the Company, effective April 14, 2014. Mr. MacFarlane joined OTP in 2001 and had served as its President from 2003 to 2014 and its Chief Executive Officer from 2007 to 2014. He served as Senior Vice President, Electric platform of the Company from 2012 to 2014. Prior to joining OTP, Mr. MacFarlane served as Director of Electric Distribution Planning and Engineering for Xcel Energy Inc.'s multi-state service territory. He was also Director of Delivery Construction and Field Operations for Northern States Power Company prior to its merger with New Centuries Energy and becoming Xcel Energy.

On April 14, 2014 Timothy J. Rogelstad was appointed to succeed Mr. MacFarlane as President of OTP and Senior Vice President, Electric Platform of the Company. Mr. Rogelstad joined OTP in June 1989 as an engineer in the System Engineering Department and served as Supervisor, Transmission Planning, and Manager, Delivery Planning, before being named Vice President, Asset Management, in 2012. In the role of Vice President, Asset Management at OTP, he was in charge of OTP's Delivery Planning, Delivery Maintenance, Delivery Engineering, System Operations, and Project Management Departments. Mr. Rogelstad is a registered professional engineer in the three states where OTP serves, Minnesota, North Dakota, and South Dakota.

On February 5, 2015 John Abbott was selected to serve as Senior Vice President, Manufacturing Platform, and President of Varistar. Prior to coming to the Company, Mr. Abbott served as an officer and group vice president for eight years at Standex International Corporation (Standex), a group of restaurant equipment companies,. During his last five years at Standex, Mr. Abbott served as Group Vice President, Food Service Equipment Group. In this role, Mr. Abbott was responsible for all strategic and operational aspects of the Food Service Equipment business. Prior to working at Standex, Mr. Abbott was with Pentair for 20 years, rising from product manager to president and global business unit leader of its water filtration division.

George A. Koeck and Kevin G. Moug have each held their present positions with the Company for more than five years.

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

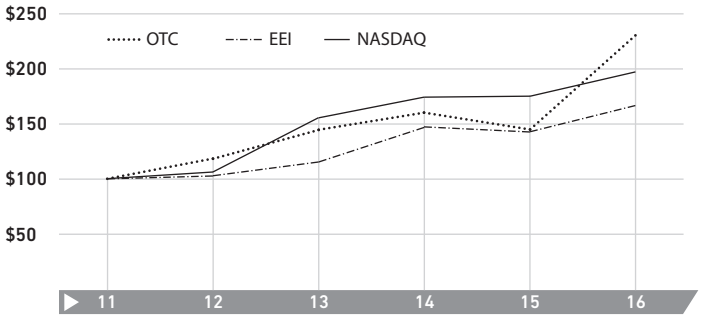
ITEM 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company's common stock is traded on the NASDAQ Global Select Market under the NASDAQ symbol "OTTR". The information required by this Item can be found below under the heading "Selected Financial Data," on Page 73 under the heading "Retained Earnings and Dividend Restriction" and on Page 87 under the heading "Supplementary Financial Information." The Company does not have a publicly announced stock repurchase program. The Company did not repurchase any equity securities during the three months ended December 31, 2016.

PERFORMANCE GRAPH

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

This graph compares the cumulative total shareholder return on the Company's common shares for the last five fiscal 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, 2011, and reinvestment of all dividends).



	2011	2012	2013	2014	2015	2016
OTC	$ 100.00	$ 119.53	$ 145.91	$ 160.79	$ 144.62	**$ 230.05**
EEI	$ 100.00	$ 102.09	$ 115.37	$ 148.72	$ 142.92	**$ 167.84**
NASDAQ	$ 100.00	$ 116.43	$ 155.41	$ 174.78	$ 175.62	**$ 198.47**

ITEM 6. Selected Financial Data

(thousands, except number of shareholders and per-share data)	**2016**	2015	2014	2013	2012
Revenues					
Electric	**$ 427,383**	$ 407,131	$ 407,743	$ 373,540	$ 350,765
Manufacturing	**221,289**	215,011	219,583	204,997	208,965
Plastics	**154,901**	157,758	172,050	164,957	150,517
Intersegment Eliminations	**(34)**	(96)	(114)	(80)	(82)
Total Operating Revenues	**$ 803,539**	$ 779,804	$ 799,262	$ 743,414	$ 710,165
Net Income from Continuing Operations	**$ 62,037**	$ 58,589	$ 56,883	$ 48,595	$ 46,034
Net Income (Loss) from Discontinued Operations	**284**	756	840	2,270	(51,307)
Net Income (Loss)	**$ 62,321**	$ 59,345	$ 57,723	$ 50,865	$ (5,273)
Operating Cash Flow from Continuing Operations	**$ 163,541**	$ 131,540	$ 125,769	$ 142,408	$ 155,026
Operating Cash Flow—Continuing and Discontinued Operations	**163,386**	117,540	112,474	147,781	233,547
Capital Expenditures—Continuing Operations	**161,259**	160,084	163,582	159,833	114,186
Total Assets *(1)*	**1,912,385**	1,818,683	1,738,116	1,558,190	1,567,523
Long-Term Debt *(1)*	**505,341**	443,846	495,906	387,212	417,830
Basic Earnings Per Share—Continuing Operations *(2)*	**1.61**	1.56	1.56	1.33	1.25
Basic Earnings (Loss) Per Share—Total *(2)*	**1.62**	1.58	1.58	1.39	(0.17)
Diluted Earnings Per Share—Continuing Operations *(2)*	**1.60**	1.56	1.55	1.33	1.25
Diluted Earnings (Loss) Per Share—Total *(2)*	**1.61**	1.58	1.57	1.39	(0.17)
Return on Average Common Equity *(3)*	**9.8%**	10.1%	10.4%	9.5%	(1.1)%
Dividends Declared Per Common Share	**1.25**	1.23	1.21	1.19	1.19
Dividend Payout Ratio	**78%**	78%	77%	86%	—
Common Shares Outstanding—Year End	**39,348**	37,857	37,218	36,272	36,168
Number of Common Shareholders *(4)*	**13,805**	14,062	14,134	14,252	14,584

(1) 2012 through 2015 adjusted in 2016 to reflect the netting of unamortized debt expense against related debt on the liability side of the balance sheet.

(2) Based on average number of shares outstanding.

(3) Earnings available for common shares divided by the 13-month average of month-end common equity balances.

(4) Holders of record at year end.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Otter Tail Corporation and its subsidiaries form a diverse group of businesses with operations classified into three segments: Electric, Manufacturing and Plastics. Our primary financial goals are to maximize earnings and cash flows and to allocate capital profitably toward growth opportunities that will increase shareholder value. Meeting these objectives enables us to preserve and enhance our financial capability by maintaining desired capitalization ratios and a strong interest coverage position and preserving investment grade credit ratings on outstanding securities, which, in the form of lower interest rates, benefits both our customers and shareholders.

Our strategy is to continue to grow our largest business, the regulated electric utility, which will lower our overall risk, create a more predictable earnings stream, improve our credit quality and preserve our ability to fund the dividend. Over time, we expect the electric utility business will provide approximately 75% to 85% of our overall earnings. We expect our manufacturing and plastic pipe businesses will provide 15% to 25% of our earnings, and will continue to be a fundamental part of our strategy. The actual mix of earnings from continuing operations in 2016, 2015 and 2014 was 80%, 83% and 77%, respectively, from our electric utility business and 20%, 17% and 23%, respectively, from our manufacturing and plastic pipe businesses, including unallocated corporate costs.

Reliable utility performance along with rate base investment opportunities over the next five years will provide us with a strong base of revenues, earnings and cash flows. We also look to our manufacturing and plastic pipe companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. We expect much of our growth in these businesses in the next few years will come from utilizing expanded plant capacity from capital investments made in previous years. We will also evaluate opportunities to allocate capital to potential acquisitions in our Manufacturing and Plastics segments. We are a committed long-term owner and therefore we do not acquire companies in pursuit of short-term gains. However, we will divest operating companies that no longer fit into our strategy and risk profile over the long term. In the period 2011 through 2015 we sold several businesses in execution of our announced strategy to realign our portfolio of businesses and refocus our capital investment in the electric utility.

On September 1, 2015 Miller Welding & Iron Works, Inc., a wholly owned subsidiary of BTD Manufacturing, Inc. (BTD), acquired the assets of Impulse Manufacturing, Inc. of Dawsonville, Georgia for $30.8 million in cash. A post-closing reduction in the purchase price of $1.5 million was agreed to in June 2016 resulting in an adjusted purchase price of $29.3 million. The acquired business, now operating under the name BTD-Georgia, is a full-service, high-tech metal fabricator located 30 miles north of Atlanta, Georgia. BTD-Georgia offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers.

Major growth strategies and initiatives in our future include:

- Planned capital budget expenditures of up to $936 million for the years 2017 through 2021, of which $862 million are for capital projects at Otter Tail Power Company (OTP), including $315 million for renewable wind and solar energy generation projects, $147 million for natural gas-fired generation to replace Hoot Lake Plant capacity and $116 million for transmission projects designated by the Midcontinent Independent System Operator, Inc. (MISO) as Multi-Value Projects (MVPs). The remainder of OTP's 2017-2021 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant. See "Capital Requirements" section for further discussion.
- The $315 million planned investment for renewable wind and solar energy generation projects includes the Merricourt Wind Project. In November 2016 OTP signed agreements to purchase this 150-megawatt (MW) wind farm in southeastern North Dakota that EDF Renewable Energy will design and build in 2019.
- Continued investigation and evaluation of organic growth opportunities and evaluation of opportunities to allocate capital to potential acquisitions in our Manufacturing and Plastics segments.

In 2016:

- Our Electric segment net income increased 3.0% to $49.8 million from $48.4 million in 2015.
- Our Manufacturing segment net income increased 34.1% to $5.7 million from $4.2 million in 2015.
- Our Plastics segment net income decreased 12.2% to $10.6 million from $12.1 million in 2015.
- Our net cash from continuing operations was $163.5 million.
- Capital Expenditures at OTP totaled $149.6 million as work continued on two major MISO-designated MVPs.
- We raised net proceeds of $43.9 million from the sale of 1,014,115 shares of common stock through our At-the-Market offering program and the issuance of 356,339 shares of common stock through our stock plans.
- We issued $130.0 million of long-term debt, paid $87.5 million to retire and redeem long-term debt, including the retirement of $52.3 million of our 9.000% notes due in December 2016, and reduced our short-term borrowings by $37.8 million.

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

(in thousands)	2016	2015
Operating Revenues:		
Electric	**$ 427,349**	$ 407,039
Manufacturing	**221,289**	215,011
Plastics	**154,901**	157,754
Total Operating Revenues	**$ 803,539**	$ 779,804
Net Income (Loss) From Continuing Operations:		
Electric	**$ 49,829**	$ 48,370
Manufacturing	**5,694**	4,247
Plastics	**10,628**	12,108
Corporate	**(4,114)**	(6,136)
Total Net Income From Continuing Operations:	**$ 62,037**	$ 58,589

Revenues in our Electric and Manufacturing business segments increased in 2016 compared with 2015. Major factors contributing to a $20.3 million (5.0%) increase in Electric segment revenues between the years were increased kilowatt-hour (kwh) sales to pipeline customers, increased revenue billed under an interim rate increase in Minnesota net of an estimated potential refund, an increase in transmission tariff revenues and a net increase in rider revenues related to increased rider rates, offset by a decrease in revenues from the recovery of fuel and purchased power costs due to a net reduction in those costs in 2016. Manufacturing segment revenues increased $6.3 million (2.9%). Revenues at BTD showed a net increase of $9.8 million, with revenues from BTD-Georgia, acquired in September 2015, increasing by $15.4 million. Revenues from BTD's other locations decreased $5.6 million, despite a $9.6 million increase in revenue from sales of wind tower components from BTD's Illinois plant, due to reduced sales to manufacturers of recreational, agricultural and industrial equipment as demand for these products remained soft in 2016. Revenues at T.O. Plastics, Inc. (T.O. Plastics) decreased $3.5 million, mainly due to the loss of product sales

to a major customer who began producing the product in-house in 2015. Plastics segment revenues were down $2.9 million (1.8%), despite a 10.5% increase in pounds of polyvinyl chloride (PVC) pipe sold, mainly due to lower PVC sales prices driven by lower raw material costs.

The $3.4 million increase in net income from continuing operations in 2016 compared with 2015 reflects the following:

- A $1.5 million increase in Electric segment net income due to increased net interim rates in Minnesota and increased retail rider revenues which were almost entirely offset by increased operating and income tax expenses.
- A $1.4 million increase in Manufacturing segment net income is mainly due to sales of wind tower components from BTD's Illinois plant and improved productivity and profits at BTD's Minnesota facilities.
- A $2.0 million net-of-tax decrease in Corporate net losses as a result of receiving nontaxable benefit proceeds from corporate-owned life insurance and lower operating expenses due to lower benefit and insurance costs.

offset by:

- A $1.5 million decrease in Plastics segment net income mainly due to reduced margins on pipe sales resulting from sales prices that declined more than the decline in raw material costs.

Following is a more detailed analysis of our operating results by business segment for the years ended December 31, 2016, 2015 and 2014, followed by a discussion of our financial position at the end of 2016 and our outlook for 2017.

RESULTS OF OPERATIONS

This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes. See note 2 to consolidated financial statements for a complete description of our lines of business, locations of operations and principal products and services.

Intersegment Eliminations—Amounts presented in the following segment tables for 2016, 2015 and 2014 operating revenues, cost of goods sold and other nonelectric operating expenses will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations *(in thousands)*	**2016**	2015	2014
Operating Revenues:			
Electric	**$ 34**	$ 92	$ 114
Product Sales	**—**	4	—
Cost of Products Sold	**6**	9	45
Other Nonelectric Expenses	**28**	87	69

ELECTRIC

The following table summarizes the results of operations for our Electric segment for the years ended December 31:

(in thousands)	**2016**	**% change**	2015	% change	2014
Retail Sales Revenues	**$ 376,610**	**3**	$ 364,614	1	$ 361,100
Wholesale Revenues—Company Generation	**4,584**	**83**	2,499	(78)	11,160
Net Revenue—Energy Trading Activity	**—**	**(100)**	186	(82)	1,031
Other Revenues	**46,189**	**16**	39,832	16	34,452
Total Operating Revenues	**$ 427,383**	**5**	$ 407,131	—	$ 407,743
Production Fuel	**54,792**	**28**	42,744	(36)	67,216
Purchased Power—System Use	**63,226**	**(19)**	78,150	19	65,848
Other Operation and Maintenance Expenses	**151,225**	**7**	140,768	(1)	141,936
Depreciation and Amortization	**53,743**	**20**	44,786	2	44,076
Property Taxes	**14,266**	**6**	13,512	7	12,607
Operating Income	**$ 90,131**	**3**	$ 87,171	15	$ 76,060
Electric kilowatt-hour (kwh) Sales *(in thousands)*					
Retail kwh Sales	**4,750,421**	**3**	4,593,604	(2)	4,695,062
Wholesale kwh Sales—Company Generation	**190,288**	**77**	107,510	(61)	273,454
Wholesale kwh Sales—Purchased Power Resold	**—**	**(100)**	5,547	(68)	17,303
Heating Degree Days	**5,314**	**(6)**	5,633	(22)	7,205
Cooling Degree Days	**451**	**(7)**	483	32	367

2016 Compared with 2015

The following table shows heating and cooling degree days as a percent of normal:

	2016	2015
Heating Degree Days	**84.1%**	88.2%
Cooling Degree Days	**97.4%**	103.4%

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kwh sales under actual weather conditions and expected retail kwh sales under normal weather conditions in 2016 and 2015 and between the years:

	2016 vs Normal	2015 vs Normal	2016 vs 2015
Effect on Diluted Earnings Per Share	**$ (0.067)**	$ (0.044)	$ (0.023)

The $12.0 million increase in retail revenue includes:

- An $11.0 million increase in retail revenue related to a 9.56% interim rate increase implemented in April 2016 in conjunction with OTP's 2016 general rate increase request in Minnesota.
- A $4.4 million increase in Environmental Cost Recovery (ECR) rider revenue due to the recovery of additional investment and costs related to the operation of the air quality control system (AQCS) at Big Stone Plant that was placed in service in December 2015.
- A $4.3 million increase in revenue related to an increase in retail kwh sales, mainly to pipeline customers.
- A $2.2 million increase in Transmission Cost Recovery (TCR) rider revenues related to increased investment in transmission plant.
- A $1.7 million increase in Conservation Improvement Program (CIP) cost recovery revenues directly related to additional CIP activities.

offset by:

- A $5.7 million decrease in fuel and purchased power cost recovery revenues mainly due to an 11.4% decrease in kwhs purchased partially offset by a 19.7% kwh increase in generation.

- A $3.6 million reduction in interim rate revenues recorded to provide for an estimated refund related to a modification in OTP's original request and other expected outcomes in the pending Minnesota general rate case.
- A $1.6 million decrease in revenues related to decreased consumption due to milder weather in 2016, evidenced by a 5.7% reduction in heating-degree days and 6.6% reduction in cooling-degree days between the years.
- A $0.6 million decrease in Renewable Resource Adjustment (RRA) rider revenues in North Dakota, which were down as a result of earning more federal Production Tax Credits (PTCs) to pass back to customers due to a 3.6% increase in kwhs generated from wind turbines eligible for PTCs.

A $2.1 million increase in revenue from wholesale electric sales from company-owned generation was partially offset by a $1.5 million increase in fuel costs for wholesale generation, resulting in a $0.6 million increase in wholesale revenue net of fuel costs as increased plant availability in 2016 provided greater opportunity for OTP to respond to market demand.

Other electric revenues increased $6.4 million as a result of:

- A $4.8 million increase in MISO transmission tariff revenues, mainly driven by increased investment in regional transmission lines and related returns on and recovery of Capacity Expansion 2020 (CapX2020) and MISO-designated MVP investment costs and operating expenses.
- A $3.0 million increase in MISO network integration transmission service revenues due to a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the Southwest Power Pool (SPP) in 2016.

offset by:

- A $1.3 million decrease in revenue related to a reduction in integrated transmission agreement revenues from two regional transmission providers related to the curtailment of services under one agreement and the discontinuance of another agreement.

Production fuel costs increased $12.0 million as a result of a 27.1% increase in kwhs generated from our steam-powered and combustion turbine generators related to Big Stone Plant being fully operational in 2016 after the tie in of the AQCS in 2015, as well as Coyote Station being available to run at full load in 2016 after being restricted to half load in 2015 because of boiler feed water pump problems.

The cost of purchased power to serve retail customers decreased $14.9 million due to an 11.4% decrease in kwhs purchased in combination with an 8.7% decrease in the cost per kwh purchased. Greater availability of company-owned generation in 2016 reduced the need to purchase electricity to serve retail load. The decreased cost per kwh purchased was driven by lower market demand mainly resulting from milder weather in 2016 compared with 2015.

Electric operating and maintenance expenses increased $10.5 million as a result of:

- $3.7 million in transmission expenses from the SPP as a result of a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the SPP in 2016.
- A $1.9 million increase in pollution control reagent costs at Big Stone Plant and Coyote Station related to compliance with the Environmental Protection Agency (EPA) power plant emission regulations.
- A $1.7 million increase in CIP program expenditures related to additional CIP activities.
- A $1.3 million increase in MISO transmission service charges due to increased transmission investment by other MISO members.
- A $1.1 million increase in storm repair expenses associated with excessive storm damage in OTP's Minnesota service area in July 2016 and in its North Dakota and South Dakota service areas in December 2016.
- $0.8 million related to increases in other expense categories.

Depreciation and amortization expense increased $9.0 million mainly due to the AQCS at Big Stone Plant being placed in service in December 2015 along with increased investment in transmission assets with the final phases of the Fargo-Monticello and Brookings-Southeast Twin Cities 345-kV transmission lines placed in service near the end of the first quarter of 2015.

The $0.8 million increase in property tax expense is related to property additions in Minnesota and North Dakota in 2015.

2015 Compared with 2014

Retail sales revenue increased $3.5 million mainly as a result of:

- An $8.7 million increase in ECR rider revenues related to earning a return in North Dakota and Minnesota on increasing amounts invested in the AQCS at Big Stone Plant, earning a return on the Hoot Lake Plant Mercury and Air Toxics Standards (MATS) project in North Dakota beginning in 2015, and the initiation of an ECR rider in South Dakota in December 2014 to recover costs and earn a return on amounts invested in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects.
- A $3.1 million increase in revenues recoverable under CIP riders related to an increase in CIP incentives awarded for 2014 program results as well as increases in CIP accruals for 2015 program incentives and recoverable expenditures.
- A $3.1 million increase in revenue from higher sales to pipeline customers.
- A $0.9 million increase in North Dakota RRA rider revenues.

offset by:

- A $4.8 million decrease in revenues related to a 2.2% decrease in retail kwh sales mainly resulting from milder weather in 2015, evidenced by heating-degree days that were 21.8% lower than in 2014 and 88.2% of normal. Weather impacted diluted earnings per share negatively by approximately $0.08 per share in 2015 compared with 2014 and approximately $0.05 per share compared with weather normalized sales for 2015.
- A $4.0 million decrease in revenues from the recovery of fuel and purchased power costs due to the 2.2% decrease in retail kwh sales and a 3.0% decrease in the combined cost of fuel and purchased power per kwh purchased and generated.
- A $3.0 million decrease in revenues due to lower sales to residential customers in North Dakota and Minnesota and lower sales to commercial customers in North Dakota.
- A $0.4 million reduction in Big Stone II cost recovery rider revenues in North Dakota as the North Dakota share of costs were fully recovered by March 31, 2014.

Wholesale electric revenues from company-owned generation decreased $8.7 million as a result of a 60.7% reduction in wholesale kwh sales combined with a 43.0% decrease in revenue per wholesale kwh sold. The decreases in wholesale kwh sales and prices were driven by decreased wholesale market demand resulting from milder weather in 2015. Also, OTP had fewer resources available for selling into the wholesale market. Big Stone Plant was off line from March through July 2015 for an extended maintenance outage. Coyote Station operated at reduced load in 2015 due to ongoing repairs related to a December 2014 boiler feed pump failure and fire. Hoot Lake Plant was curtailed in 2015 due to low market prices for electricity, which was a factor contributing to a strategic decision to shut down Hoot Lake Plant's Unit 3 for preventative maintenance in September 2015. Generation from company-owned wind turbines was down 6.0% from 2014, primarily due to lower average wind speeds in the first half of 2015. The decrease in wholesale prices for electricity was due, in part, to lower prices for natural gas used in the generation of electricity in 2015 compared with 2014.

Net revenue from energy trading activities decreased $0.8 million as a result of OTP discontinuing its trading activities not directly associated with serving retail customers in December 2014 due to a lack of market activity and profitable trading opportunities.

Other electric revenues increased $5.4 million, primarily as a result of an increase in MISO transmission tariff revenues related to increased investment in regional transmission projects including returns on and recovery of CapX2020 and MISO-designated MVP investment costs and operating expenses.

Production fuel costs decreased $24.5 million as a result of a 39.3% decrease in kwhs generated from OTP's steam-powered and combustion turbine generators primarily due to the factors discussed above. The cost of purchased power to serve retail customers increased $12.3 million due to a 55.7% increase in kwhs purchased, partially offset by a 23.8% decrease in the cost per kwh purchased. The increase in power purchases for retail sales was necessitated by the reduced availability of company-owned generating capacity discussed above. The decreased cost per kwh purchased was driven by lower market demand due to milder weather in 2015 in combination with lower prices for natural gas used in the generation of electricity.

Electric operating and maintenance expenses decreased $1.2 million reflecting:

- A $3.0 million net reduction in generation plant operating and maintenance costs between the years as costs incurred in 2014 at Hoot Lake Plant and Coyote Station were more than the maintenance costs incurred at Big Stone Plant in 2015. Although kwh generation decreased for all three plants in 2015, work done on the plants in 2014 was more operating and maintenance in nature while more capitalized projects were completed in 2015. Also, with the plants generating fewer kwhs in 2015, operating costs were lower in 2015.
- A $1.4 million reduction in travel related expenses as a result of increased vehicle usage on capital projects and lower fuel prices.
- A $0.7 million increase in capitalized administrative and general expenses due to more time being spent on capital projects.
- A $0.4 million reduction in the North Dakota share of Big Stone II costs being amortized as the North Dakota share of costs were fully recovered by March 31, 2014.
- An expense of $0.3 million recorded in June 2014 related to OTP not earning a return on the deferred recovery of the Minnesota share of Big Stone II abandoned transmission plant costs.

offset by:

- A $3.8 million increase in MISO transmission tariff charges related to increasing investments by other transmission owners in regional CapX2020 and MISO-designated MVP transmission projects.
- A $0.9 million increase in Minnesota CIP expenditures and new program implementation costs.

Depreciation expense increased $0.7 million as a result of increased investment in transmission, distribution and general plant placed in service in 2014 and 2015.

The $0.9 million increase in property tax expense primarily is due to increased property valuations and transmission plant additions in Minnesota.

MANUFACTURING

The following table summarizes the results of operations for our Manufacturing segment for the years ended December 31:

(in thousands)	**2016**	**% change**	2015	% change	2014
Operating Revenues	**$ 221,289**	**3**	$ 215,011	(2)	$ 219,583
Cost of Products Sold	**171,732**	**—**	171,956	2	169,033
Lease Exit Costs	**—**	**—**	—	—	2,843
Other Operating Expenses	**21,994**	**4**	21,116	3	20,497
Depreciation and Amortization	**15,794**	**33**	11,853	13	10,518
Operating Income	**$ 11,769**	**17**	$ 10,086	(40)	$ 16,692

2016 Compared with 2015

The increase in revenues in our Manufacturing segment in 2016 compared with 2015 relates to the following:

- Revenues at BTD increased $9.8 million, including:
  - A $15.4 million increase in revenues at BTD-Georgia as a result of BTD owning and operating this plant for the entire year of 2016 compared to four months in 2015.
  - A $9.6 million increase in revenues mainly related to the production of wind tower components.

offset by:

  - A $15.2 million decrease in revenues related to lower sales to manufacturers of recreational and agricultural equipment due to softness in end markets served by those manufacturers.
- Revenues at T.O. Plastics decreased $3.5 million, including:
  - A $3.0 million decrease in revenue related to a continued decline in sales to a customer insourcing product into its own manufacturing facilities.
  - A $0.6 million decrease in sales of horticultural products due to sales execution challenges, including lower sales to a major distributor.

offset by:

  - A net $0.1 million increase in sales of other products in the industrial and life sciences markets.

The decrease in cost of products sold in our Manufacturing segment includes the following:

- Cost of products sold at BTD increased $1.7 million. This includes a $15.5 million increase in cost of products sold at BTD-Georgia, offset by a $13.8 million net decrease in cost of products sold at BTD's other facilities. The $13.8 million decrease is related to the decrease in sales, partially offset by an increase in costs of products sold at BTD's Illinois plant as a result of the increase in the production of wind tower components.
- Cost of products sold at T.O. Plastics decreased $1.9 million related to the decrease in sales.

Gross margins at BTD were positively impacted in 2016 by changes in customer product mix between periods.

The $0.9 million increase in operating expenses in our Manufacturing segment includes the following:

- Operating expenses at BTD increased $1.4 million, of which $1.2 million was due to a full year of operations at BTD-Georgia in 2016.
- Operating expenses at T.O. Plastics decreased $0.4 million, primarily as a result of a $0.5 million decrease in selling expenses.

The $3.9 million increase in depreciation and amortization expenses in our Manufacturing segment includes a $2.3 million increase at BTD-Georgia and a $1.8 million increase at BTD's other plants mainly as a result of placing new assets in service in Minnesota in 2015 and 2016. Depreciation expense at T.O. Plastics decreased $0.2 million between the years.

2015 Compared with 2014

The decrease in revenues in our Manufacturing segment in 2015 compared with 2014 relates to the following:

- Revenues at BTD decreased $6.6 million (3.5%) due to the following:
  - An $8.6 million decrease in sales, mainly to manufacturers of oil and gas exploration and extraction equipment as a result of a reduction in drilling activity related to low oil prices.
  - A $3.2 million decrease in sales of scrap metal due to a reduction in scrap metal prices and a reduction in scrap volume related to lower production and sales volumes between years.
  - A $2.1 million decrease in sales to manufacturers of agricultural equipment related to continued softness in the agricultural industry.
  - A $1.5 million reduction in tooling revenues.
  - Offset by $8.8 million in sales at BTD-Georgia, acquired on September 1, 2015.
- Revenues at T.O. Plastics increased $2.0 million (6.1%) reflecting:
  - A $1.4 million increase in sales of horticultural containers.
  - A $0.5 million increase in sales of custom products.
  - A $0.1 million increase in sales of various other products to industrial customers.

The increase in cost of products sold in our Manufacturing segment relates to the following:

- Cost of products sold at BTD decreased $0.4 million, reflecting an $8.7 million decrease in costs related to decreased sales, offset by $8.3 million in costs incurred at BTD-Georgia from September through December 2015.
- Cost of products sold at T.O. Plastics increased $3.3 million due to increases in material, labor and freight costs related to the increase in sales at T.O. Plastics.

The $2.8 million reduction in Manufacturing segment operating expenses related to the lease exit costs incurred in 2014, was partially offset by $0.6 million in operating expenses incurred at BTD-Georgia from September through December 2015. Labor and benefit expense increases of $1.0 million at BTD were mostly offset by a $0.9 million reduction in labor and benefit expenses at T.O. Plastics between the years.

Depreciation and amortization expense at BTD-Georgia from September through December 2015 was approximately $1.0 million. A $0.6 million increase in depreciation expense at BTD related to recent asset additions under its Minnesota facilities expansion plan was partially offset by a $0.3 million decrease in depreciation expense at T.O. Plastics as a result of certain assets reaching the end of their depreciable lives.

PLASTICS

The following table summarizes the results of operations for our Plastics segment for the years ended December 31:

(in thousands)	**2016**	**% change**	2015	% change	2014
Operating Revenues	**$ 154,901**	**(2)**	$ 157,758	(8)	$ 172,050
Cost of Products Sold	**123,496**	**—**	123,085	(12)	139,081
Other Operating Expenses	**9,402**	**(5)**	9,849	6	9,292
Depreciation and Amortization	**3,861**	**9**	3,552	6	3,364
Operating Income	**$ 18,142**	**(15)**	$ 21,272	5	$ 20,313

2016 Compared with 2015

The $2.9 million decrease in Plastics segment revenues is the result of an 11.2% decrease in the price per pound of pipe sold, partially offset by a 10.5% increase in pounds of pipe sold. The decline in sales price per pound is related to lower raw material prices between the periods. Increased pipe sales in the Colorado, Utah, and the South Central and Northwest regions of the United States were partially offset by decreased sales volumes in Montana, South Dakota and Minnesota. Cost of products sold increased $0.4 million due to the increase in sales volume, partly offset by a 9.2% decrease in the cost per pound of PVC pipe sold, as sales prices declined more than raw material prices. Lower margins have resulted in reduced incentive compensation, which is the primary factor contributing to the $0.4 million decrease in Plastics segment operating expenses.

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower.

2015 Compared with 2014

The $14.3 million decrease in Plastics segment revenues is the result of a 7.0% decrease in the price per pound of pipe sold in combination with a 1.4% decrease in pounds of PVC pipe sold. The decrease in sales are due in part to delayed purchases related to falling resin prices and in part to reduced demand in the region of the United States between the Mississippi River and the Rocky Mountain states, especially in Texas where soft markets were exacerbated by severe spring flooding. The $16.0 million decrease in costs of products sold is mainly due to a 10.2% decrease in the cost per pound of pipe sold as a result of lower resin prices. The $0.6 million increase in operating expenses was mainly related to increased wage and benefit costs.

CORPORATE

Corporate includes 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 totals on our consolidated statements of income.

(in thousands)	**2016**	**% change**	2015	% change	2014
Airplane Rent and Lease Exit Costs	**$ —**	**—**	$ —	—	$ 3,012
Other Operating Expenses	**8,896**	**(3)**	9,143	(12)	10,406
Depreciation and Amortization	**47**	**(73)**	172	48	116

Corporate operating expenses decreased $0.2 million in 2016 as compared to 2015 as a result of decreased expenditures for contracted services and a decrease in claims at our captive insurance company, partially offset by a decrease in expenses allocated to OTP.

Corporate operating expenses decreased $4.3 million in 2015 compared with 2014 primarily due to:

- A $3.0 million reduction in airplane operating lease expense related to the early termination of an airplane lease in the second quarter of 2014, as divestitures had reduced the need for the airplane. The cost to terminate the lease early was approximately $2.5 million or a net-of-tax impact on diluted earnings per share of ($0.04).
- A $0.8 million reduction in insurance costs at our captive insurance company related to lower claims activity in 2015.
- A $0.5 million decrease in labor expense due to a reduction in employees in 2015.

CONSOLIDATED INTEREST CHARGES

(in thousands)	2016	% change	2015	% change	2014
Interest Charges	**$ 31,886**	**2**	$ 31,160	5	$ 29,648

The $0.7 million increase in interest charges in 2016 compared with 2015 is due to an increase in interest expense on short-term debt at OTP as a result of a $24.7 million increase in OTP's daily average balance of short-term debt outstanding between the years and a $0.2 million decrease in capitalized interest expense. The increase in OTP's use of short-term borrowing is related to its increasing investment in two major MVP transmission line projects under construction.

The $1.5 million increase in interest charges in 2015 compared with 2014 is mainly due to:

- A $1.3 million increase in interest expense incurred in January and February of 2015 at OTP related to the February 27, 2014 issuance of $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044.
- A $19.6 million increase in the daily average balance of short-term debt outstanding in 2015 compared with 2014.

CONSOLIDATED OTHER INCOME

(in thousands)	2016	% change	2015	% change	2014
Other Income	**$ 2,905**	**33**	$ 2,177	(39)	$ 3,557

The $0.7 million increase in other income in 2016 compared with 2015 is mainly due to benefit proceeds from corporate-owned life insurance received in 2016.

The $1.4 million decrease in other income in 2015 compared with 2014, includes:

- A $0.8 million gain on the sale of an investment in tax-credit-qualified low income housing rental property in 2014 that was not duplicated in 2015.
- A $0.3 million reduction in other income at OTP related to reductions in allowance for equity funds used in construction (AFUDC) and carrying charges earned on funds invested in Minnesota CIP prior to recovery, in alignment with a decrease in short-term borrowing rates.
- A $0.2 million reduction in corporate-owned life insurance cash surrender value increases.

CONSOLIDATED INCOME TAXES

Income tax expense—continuing operations was $20.1 million in 2016 compared with $21.6 million in 2015 and $16.6 million in 2014. The following table provides a reconciliation of income tax expense—continuing operations calculated at the federal statutory rate on income from continuing operations before income taxes reported on our consolidated statements of income:

	For the Year Ended December 31,		
(in thousands)	**2016**	2015	2014
Tax Computed at Federal Statutory Rate—Continuing Operations	**$ 28,741**	$ 28,081	$ 25,704
Increases (Decreases) in Tax from:			
Federal PTCs	**(7,175)**	(6,962)	(7,517)
State Income Taxes Net of Federal Income Tax Expense	**2,848**	4,945	1,993
North Dakota Wind Tax Credit Amortization—Net of Federal Taxes	**(850)**	(850)	(849)
Corporate-owned Life Insurance	**(680)**	(167)	(354)
Dividend Received/Paid Deduction	**(537)**	(560)	(622)
Section 199 Domestic Production Activities Deduction	**(482)**	—	(1,026)
Investment Tax Credit Amortization	**(350)**	(571)	(597)
AFUDC—Equity	**(280)**	(426)	(505)
Differences Reversing in Excess of Federal Rates	**77**	(1,143)	(106)
Permanent and Other Differences	**(1,231)**	(705)	436
Total Income Tax Expense—Continuing Operations	**$ 20,081**	$ 21,642	$ 16,557
Effective Income Tax Rate—Continuing Operations	**24.5%**	27.0%	22.5%

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 3.6% in 2016 compared with 2015. OTP's kwh generation from its wind turbines eligible for PTCs decreased 7.4% in 2015 primarily due to lower average wind speed in 2015 compared with 2014. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

DISCONTINUED OPERATIONS

On April 30, 2015 we sold Foley Company (Foley) for $12.0 million in cash, plus $6.3 million in adjustments for working capital and other related items received in October 2015, less $1.0 million in selling expenses. On February 28, 2015 we sold the assets of AEV, Inc. for $22.3 million in cash, plus $0.6 million in adjustments for working capital and fixed assets received in October 2015, less $0.8 million in selling expenses. Foley and AEV, Inc were formerly included in our Construction segment.

On February 8, 2013 we completed the sale of substantially all the assets of our dock and boatlift company, formerly included in our Manufacturing segment. On November 30, 2012 we completed the sale of the assets of our wind tower manufacturing business. This business was the only remaining entity in our former Wind Energy segment.

Our Wind Energy and Construction segments were eliminated as a result of the sales of our wind tower manufacturing business, Foley and AEV, Inc. The financial position, results of operations and cash flows of Foley, AEV, Inc., our wind tower manufacturing business and our dock

and boatlift company are reported as discontinued operations in our consolidated financial statements. Following are the results of discontinued operations by entity for the years ended December 31, 2016, 2015 and 2014:

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
2016 Net (Loss) Income	$ (114)	$ (5)	$ 454	$ (51)	$ —	$ 284
2015 Net (Loss) Income	$ (5,489)	$ 6,216	$ 344	$ (580)	$ 265	$ 756
2014 Net (Loss) Income	$ (3,034)	$ 2,621	$ (11)	$ 274	$ 990	$ 840

Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges of $4.4 million in 2015.

IMPACT OF INFLATION

OTP operates under regulatory provisions that allow price changes in fuel and certain purchased power costs to be passed to most retail customers through automatic adjustments to its rate schedules under fuel clause adjustments. Other increases in the cost of electric service must be recovered through timely filings for electric rate increases with the appropriate regulatory agency.

Our Manufacturing and Plastics segments consist entirely of businesses whose revenues are not subject to regulation by ratemaking authorities. Increased operating costs are reflected in product or services pricing with any limitations on price increases determined by the marketplace. Raw material costs, labor costs, fuel and energy costs and interest rates are important components of costs for companies in these segments. Any or all of these components could be impacted by inflation or other pricing pressures, with a possible adverse effect on our profitability, especially where increases in these costs exceed price increases on finished products. In recent years, our operating companies have faced strong inflationary and other pricing pressures with respect to steel, fuel, resin, and health care costs, which have been partially mitigated by pricing adjustments.

LIQUIDITY

The following table presents the status of our lines of credit as of December 31, 2016 and December 31, 2015:

(in thousands)	Line Limit	In Use on December 31, 2016	Restricted due to Outstanding Letters of Credit	Available on December 31, 2016	Available on December 31, 2015
Otter Tail Corporation Credit Agreement	$ 130,000	$ —	$ —	$ 130,000	$ 90,334
OTP Credit Agreement	170,000	42,883	50	127,067	148,694
Total	$ 300,000	$ 42,883	$ 50	$ 257,067	$ 239,028

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if needed. Our balance sheet is strong and we are in compliance with our debt covenants. Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings and alternative financing arrangements such as leasing.

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2015 we filed a shelf registration statement with the Securities and Exchange Commission (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, which expires on May 11, 2018. On May 11, 2015, we entered into a Distribution Agreement with J.P. Morgan Securities LLC (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million through an At-the-Market offering program. We sold 36,403 shares at the end of the third quarter of 2016 under this program that were settled in October 2016 and received proceeds of $1,256,000 net of $16,000 in commissions paid to JPMS.

Equity or debt financing will be required in the period 2017 through 2021 given the expansion plans related to our Electric segment to fund construction of new rate base investments. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating

agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 8 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the board of directors. On February 2, 2017 our board of directors increased the quarterly dividend from $0.3125 to $0.32 per common share.

2016 Cash Flows Compared with 2015 Cash Flows

Cash provided by operating activities of continuing operations was $163.5 million in 2016 compared with $131.5 million in 2015. The $32.0 million increase in cash provided by continuing operations between the years includes a $32.8 million reduction in cash used for working capital items due to:

- An $18.2 million decrease in cash used for accounts payable and other current liabilities at OTP, reflecting higher levels of payables in December 2016 for coal deliveries and transmission services related to the colder temperatures in December 2016 and the payment, in January 2015, of large billings for coal transportation, coal and power purchased in December 2014.
- A $10.7 million decrease in cash used for accounts payable and other current liabilities at the plastic pipe companies related to an increase in year-end resin purchases in 2016 compared to 2015.
- A $7.3 million decrease in cash used for interest payable and income taxes receivable between the years, mainly related to having made a $4.0 million estimated tax payment in December 2015 that was refunded in the first quarter of 2016, as a five-year extension of bonus depreciation for income taxes, approved on December 18, 2015, resulted in a lower federal income tax liability for the Company in 2015.

offset by:

- A $2.3 million increase in unbilled revenues at OTP between the years resulting from the 2016 increase in interim rates in Minnesota and increased kwh sales due to colder weather in December 2016 compared with December 2015.

In continuing operations, net cash used in investing activities was $159.3 million in 2016 compared with $193.6 million in 2015. The $34.3 million decrease in cash used for investing activities includes a $32.3 million decrease in cash used in acquisitions as we paid $30.8 million to acquire the assets of BTD-Georgia in September 2015 and received a purchase price adjustment of $1.5 million in June 2016.

Net cash used in financing activities of continuing operations was $4.1 million in 2016 compared with net cash provided by financing activities of $38.1 million in 2015. Financing activities in 2016 included:

- $80.0 million in proceeds from the issuance of our 3.55% Guaranteed Senior Notes due December 15, 2026 in December 2016.
- $50.0 million borrowed under our term loan agreement in February 2016.
- $32.8 million in net proceeds from the issuance of 1,014,115 shares of common stock under the Company's At-the-Market offering program.
- $11.1 million in net proceeds from the issuance of 356,399 shares of common stock under the Company's automatic dividend reinvestment and share purchase plans.

offset by:

- The repayment of the $52.3 million balance of our 9.000% notes due in December 2016.
- A $41.2 million reduction of short-term borrowings and checks written in excess of cash.
- The repayment of $35.0 million of funds borrowed in February 2016 under our term loan agreement.
- $48.2 million in common stock dividend payments.

The outstanding short-term borrowings that were paid down were, in part, used to fund the expansion of BTD's Minnesota facilities in 2015 and the September 1, 2015 acquisition of BTD-Georgia. See note 6 to the Company's consolidated financial statements for further information on stock issuances and retirements in 2016.

2015 Cash Flows Compared with 2014 Cash Flows

Cash provided by operating activities from continuing operations was $131.5 million in 2015 compared with $125.8 million in 2014. Contributing to the $5.7 million increase in cash provided by continuing operations between the periods were:

- A $10.0 million decrease in discretionary contributions to the Company's pension plan.
- A $2.3 million increase in depreciation expense.
- A $1.6 million increase in net income from continuing operations.

offset by:

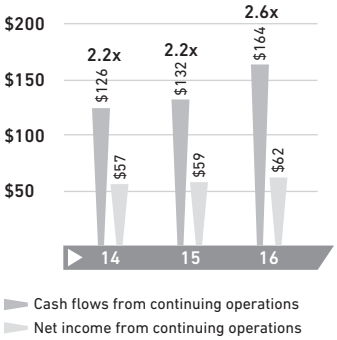
- $7.2 million in cash used to decrease accounts payable at OTP in 2015 partly related to power purchases and repair services incurred in connection with the boiler pump failure and fire at Coyote Station in December 2014.

In continuing operations, net cash used in investing activities was $193.6 million in 2015 compared with $163.9 million in 2014. The purchase of the assets of BTD-Georgia for $30.8 million on September 1, 2015 was the main factor contributing to the $29.7 million increase in cash used in investing activities of continuing operations between the periods. A $3.4 million decrease in cash used for capital expenditures includes a $13.1 million reduction in capital expenditures at OTP as several major projects were completed and placed in service in 2015, including two CapX2020 transmission line projects and the new AQCS at Big Stone Plant, partially offset by a $9.0 million increase in cash used for capital expenditures in our Manufacturing segment, mainly at BTD as it moved forward with its project to expand and realign its Minnesota production and warehouse facilities.

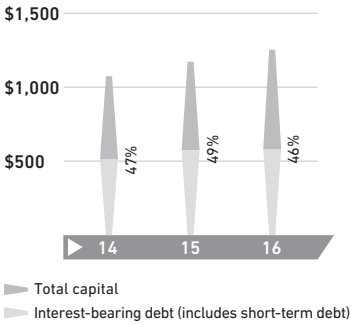
Investing activities of discontinued operations in 2015 includes cash proceeds, net of selling expenses, of $22.1 million from the sale of AEV, Inc. and $17.3 million from the sale of Foley, partially offset by $1.8 million in cash used in investing activities of discontinued operations, mainly related to the purchase by AEV, Inc. of assets being leased under operating leases prior to the assets being sold.

Net cash provided by financing activities of continuing operations was $38.1 million in 2015 compared with $49.7 million in 2014. Net cash provided by financing activities in 2015 includes $69.8 million in short-term borrowings used to fund a portion of our capital expenditures and the acquisition of BTD-Georgia. Net cash proceeds of $13.8 million from the issuance of common stock under our At-the-Market offering program and various stock purchase and dividend reinvestment plans were also used to fund a portion of our capital expenditures. See note 6 to the Company's consolidated financial statements for further information on stock issuances and retirements in 2015. Cash used for common stock dividend payments totaled $46.2 million in 2015.

CASH REALIZATION (millions)



INTEREST-BEARING DEBT AS A PERCENT OF TOTAL CAPITAL (millions)



CAPITAL REQUIREMENTS

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

Cash used for consolidated capital expenditures was $161.3 million in 2016, $160 million in 2015 and $164 million in 2014. Estimated capital expenditures for 2017 are $149 million. Total capital expenditures for the five-year period 2017 through 2021 are estimated to be approximately $936 million, which includes $315 million for renewable wind and solar energy generation projects, $147 million for natural gas-fired generation to replace Hoot Lake Plant capacity and $116 million for OTP transmission projects designated by the MISO as MVPs.

The breakdown of 2014, 2015 and 2016 actual cash used for capital expenditures and 2017 through 2021 estimated capital expenditures by segment is as follows:

(in millions)	2014	2015	2016	2017	2018	2019	2020	2021	2017-2021
Electric	$ 149	$ 136	$ 150	$135	$173	$346	$130	$ 78	$ 862
Manufacturing	11	20	8	10	13	11	10	10	54
Plastics	4	4	3	4	4	4	4	4	20
Total	$ 164	$ 160	$ 161	$149	$190	$361	$144	$ 92	$ 936

The following table summarizes our contractual obligations at December 31, 2016 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Coal Contracts (required minimums)	**$ 671**	$ 31	$ 44	$ 45	$ 551
Debt Obligations	**584**	76	15	141	352
Interest on Debt Obligations	**337**	27	50	50	210
Capacity and Energy Requirements	**277**	24	49	38	166
Postretirement Benefit Obligations	**100**	5	11	11	73
Other Purchase Obligations	**85**	74	11	—	—
Operating Lease Obligations	**40**	7	9	7	17
Total Contractual Cash Obligations	**$2,094**	$ 244	$ 189	$292	$1,369

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, but do not include amounts to fund our noncontributory funded pension plan, as we are not currently required to make a contribution to that plan.

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings, and alternative financing arrangements such as leasing. Equity or debt financing will be required in the period 2017 through 2021 given the expansion plans related to our Electric segment to fund construction of new rate base and transmission investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

Under our shelf registration statement filed with the SEC 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, until May 11, 2018.

Under our At-the-Market offering program, we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million, of which $39.2 million remained available at December 31, 2016. Under the Distribution Agreement with JPMS, we will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. We are not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement.

SHORT-TERM DEBT

The following table presents the status of our lines of credit as of December 31, 2016 and December 31, 2015:

(in thousands)	Line Limit	In Use on December 31, 2016	Restricted due to Outstanding Letters of Credit	Available on December 31, 2016	Available on December 31, 2015
Otter Tail Corporation Credit Agreement	$ 130,000	$ —	$ —	$ 130,000	$ 90,334
OTP Credit Agreement	170,000	42,883	50	127,067	148,694
Total	$ 300,000	$ 42,883	$ 50	$ 257,067	$ 239,028

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2016 was $63,757,000 on January 4, 2016 and the average daily balance of debt outstanding during 2016 was $16,200,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2016 was 2.3% compared with 2.0% in 2015. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2016 was $51,885,000 on December 16, 2016 and the average daily balance of debt outstanding during 2016 was $32,576,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2016 was 1.8% compared with 1.5% in 2015. The maximum amount of consolidated short-term debt outstanding in 2016 was $87,211,000 on January 25, 2016 and the average daily balance of consolidated short-term debt outstanding during 2016 was $48,776,000. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2016 was 1.9%.

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $130 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 31, 2016 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2020 to October 29, 2021 and the unsecured revolving credit facility was reduced from $150 million to $130 million. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of certain of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on our senior unsecured credit ratings. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation (Varistar) and its subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2016 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2020 to October 29, 2021. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its 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 OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

LONG-TERM DEBT

2016 Note Purchase Agreement

On September 23, 2016 we entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which we agreed to issue to the purchasers, in a private placement transaction, $80 million aggregate principal amount of our 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The 2026 Notes were issued on December 13, 2016. Our obligations under the 2016 Note Purchase Agreement and the 2026 Notes are guaranteed by our Material Subsidiaries (as defined in the 2016 Note Purchase Agreement, but specifically excluding OTP). The proceeds from the issuance of the 2026 Notes were used to repay the remaining $52,330,000 of our 9.000% Senior Notes due December 15, 2016, and to pay down a portion of the $50 million in funds borrowed in February 2016 under our term loan agreement.

We may prepay all or any part of the 2026 Notes (in an amount not less than 10% of the aggregate principal amount of the 2026 Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2016 Note Purchase Agreement, any optional prepayment made by us of all of the 2026 Notes on or after September 15, 2026 will be made without any make-whole amount. We are required to offer to prepay all of the outstanding 2026 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2016 Note Purchase Agreement) of the Company. In addition, if we and our Material Subsidiaries sell a "substantial part" of our or their assets and use the proceeds to prepay or retire senior Interest-bearing Debt (as defined in the 2016 Note Purchase Agreement) of the Company and/or a Material Subsidiary in accordance with the terms of the 2016 Note Purchase Agreement, we are required to offer to prepay a Ratable Portion (as defined in the 2016 Note Purchase Agreement) of the 2026 Notes held by each holder of the 2026 Notes.

The 2016 Note Purchase Agreement contains a number of restrictions on the business of the Company and our Material Subsidiaries. These include restrictions on our and our Material Subsidiaries' abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, engage in transactions with related parties, redeem or pay dividends on our and our Material Subsidiaries' shares of capital stock, and make investments. The 2016 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2016 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our or our Material Subsidiaries' credit ratings.

Term Loan Agreement

On February 5, 2016 we entered into a Term Loan Agreement (the Term Loan Agreement) with the Banks named therein, JPMorgan Chase Bank, N.A. (JPMorgan), as administrative agent, and JPMS, as Lead Arranger and Book Runner. The Term Loan Agreement provides for an unsecured term loan with an aggregate commitment of $50 million that we may use for purposes of funding working capital, capital expenditures and other corporate purposes of the Company and certain of our subsidiaries. Under the Term Loan Agreement, we may, on up to two occasions, enter into additional tranches of term loans in minimum increments of $10 million, subject to the consent of the lenders and so long as the aggregate amount of outstanding term loans does not exceed $100 million at any time. Borrowings under the Term Loan Agreement will bear interest at either (1) LIBOR plus 0.90% or (2) the greater of (a) the Prime Rate, (b) the Federal Reserve Bank of New York Rate plus 0.50% and (c) LIBOR multiplied by the Statutory Reserve Rate plus 1%. The applicable interest rate will depend on our election of whether to make the advance a LIBOR advance. The Term Loan Agreement terminates on February 5, 2018.

On February 5, 2016 we borrowed $50 million under the Term Loan Agreement at an interest rate based on the 30 day LIBOR plus 90 basis points and used the proceeds to pay down borrowings under the Otter Tail Corporation Credit Agreement that were used to fund the expansion of BTD's Minnesota facilities in 2015 and to fund the September 1, 2015 acquisition of BTD-Georgia. We repaid $35.0 million under the Term Loan Agreement in the fourth quarter of 2016.

The Term Loan Agreement contains a number of restrictions on us, Varistar and certain subsidiaries of Varistar, including restrictions on our and their 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 Term Loan Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The Term Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Term Loan Agreement are guaranteed by Varistar and certain of its subsidiaries.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the Purchasers named therein, pursuant to which OTP agreed to issue to the Purchasers, in a private placement transaction, $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). On February 27, 2014 OTP issued all $150 million aggregate principal amount of the Notes.

The 2013 Note Purchase Agreement states that 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 prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's 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 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be

incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (2011 Note Purchase Agreement). OTP also has outstanding its $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement).

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (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 prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's 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 note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Financial Covenants

We were in compliance with the financial covenants in our debt agreements as of December 31, 2016.

No Credit or Note Purchase Agreement contains 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.

Our borrowing agreements are subject to certain financial covenants. Specifically:

- Under the Otter Tail Corporation Credit Agreement, the Term Loan Agreement and the 2016 Note Purchase Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis). As of December 31, 2016 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement, the Term Loan Agreement and the 2016 Note Purchase Agreement was 3.68 to 1.00.
- Under the 2016 Note Purchase Agreement, we may not permit our Priority Indebtedness to exceed 10% of our Total Capitalization.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.
- Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of December 31, 2016 OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.64 to 1.00.
- Under the 2013 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, each as provided in the 2013 Note Purchase Agreement.

As of December 31, 2016 our ratio of Interest-bearing Debt to Total Capitalization was 0.46 to 1.00 on a consolidated basis and 0.47 to 1.00 for OTP. Neither Otter Tail Corporation or OTP had any Priority Indebtedness outstanding as of December 31, 2016.

Our ratio of earnings to fixed charges from continuing operations reported in Exhibit 12.1 to this Annual Report on Form 10-K, which includes imputed finance costs on operating leases, was 3.4x for 2016 and 2015. During 2017, we expect this coverage ratio to increase, assuming 2017 net income meets our expectations.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $4.6 million, but our line of credit borrowing limits are only restricted by $50,000 in outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2017 BUSINESS OUTLOOK

We anticipate 2017 diluted earnings per share to be in the range of $1.60 to $1.75. This guidance reflects the current mix of businesses we own, considers the cyclical nature of some of our businesses, and reflects current regulatory factors and economic challenges facing our Electric, Manufacturing and Plastics segments and strategies for improving future operating results. We expect capital expenditures for 2017 to be $149 million compared with actual cash used for capital expenditures of $161 million in 2016. Major projects in our planned expenditures for 2017 include investments in two large transmission line projects for the Electric segment, which positively impact earnings by providing an immediate return on invested funds through rider recovery mechanisms.

Segment components of our 2017 earnings per share guidance range compared with 2016 actual earnings are as follows:

	2016 EPS by Segment	2017 EPS Guidance Low	2017 EPS Guidance High
Electric	$ 1.29	$ 1.31	$ 1.34
Manufacturing	$ 0.15	$ 0.17	$ 0.21
Plastics	$ 0.27	$ 0.26	$ 0.30
Corporate	$ (0.11)	$ (0.14)	$ (0.10)
Total—Continuing Operations	$ 1.60	$ 1.60	$ 1.75

Contributing to our earnings guidance for 2017 are the following items:

- We expect 2017 Electric segment net income to be higher than 2016 segment net income based on:
  - Normal weather for 2017. Milder than normal weather in 2016 negatively impacted diluted earnings per share by $0.07 compared to normal.
  - Constructive outcome of a rate case filed in Minnesota on February 16, 2016 with a full year of increased rates compared with 8.5 months in 2016. The Minnesota Public Utilities Commission determines our rates. Our ability to obtain final rates similar to interim rates and reasonable rates of return depends on regulatory action under applicable statutes and regulations. We cannot provide assurance our interim rates will become final and that our modifications to our original request will ultimately be approved.
  - Rider recovery increases, including transmission riders related to the Electric segment's continuing investments in its share of the MVPs in South Dakota.
  - Expected increases in sales to pipeline and commercial customers.

offset by:

  - Increased operating and maintenance expenses of $0.06 per share due to inflationary increases and increasing costs of medical, workers compensation and retiree medical. Included is an increase in pension costs as a result of a decrease in the discount rate from 4.76% to 4.60% and a decrease in the assumed long-term rate of return on plan assets from 7.75% to 7.50%.
  - Higher depreciation and property tax expense due to large capital projects being put into service.
  - Lower CIP incentives of $0.04 per share in Minnesota as a result of program changes made by the state. OTP estimates the implementation of the new CIP financial incentive model will reduce these incentives by approximately 50% compared to the previous incentive mechanism.
  - Increased costs related to contractual price increases in certain capacity agreements.
- We expect 2017 net income from our Manufacturing segment to increase over 2016 due to:
  - Increased sales of 4.5% coming primarily from the lawn and garden end markets. We continue to see soft end markets in agriculture, oil and gas.
  - Improved margins on parts and tooling sales given improved productivity across all of BTD's locations and lower interest costs as a result of the refinancing of long-term debt completed in the fourth quarter of 2016.
  - An increase in earnings from T.O. Plastics mainly driven by year over year sales growth in our horticulture and custom markets and lower interest costs as a result of the refinancing of long-term debt completed in the fourth quarter of 2016.
  - Backlog for the manufacturing companies of approximately $118 million for 2017 compared with $134 million one year ago.
- We expect 2017 net income from the Plastics segment to be similar to 2016. Sales volumes in 2017 are expected to be down compared with 2016 due to lower sales in the Southern California and Texas markets offset by strengthening sales prices resulting in improved operating margins year over year. The Plastics segment also benefits from lower interest costs as a result of the refinancing of long term debt completed in the fourth quarter of 2016.
- Corporate costs in 2017 are expected to be in line with 2016 costs.

The following table shows our 2016 capital expenditures and 2017 through 2021 anticipated capital expenditures and electric utility average rate base:

(in millions)	2015	2016	2017	2018	2019	2020	2021	Total
Capital Expenditures:								
Electric Segment:								
Renewables and Natural Gas Generation			$ 3	$ 80	$ 288	$ 71	$ 20	$ 462
Transmission			88	49	11	11	7	166
Other			44	44	47	48	51	234
Total Electric Segment		$ 150	$ 135	$ 173	$ 346	$ 130	$ 78	$ 862
Manufacturing and Plastics Segments		11	14	17	15	14	14	74
Total Capital Expenditures		$ 161	$ 149	$ 190	$ 361	$ 144	$ 92	$ 936
Total Electric Utility Average Rate Base	$ 919	$1,001*	$1,063	$1,118	$1,267	$1,396	$1,419	

**Estimated*

The consolidated capital expenditure plan for the 2017-2021 time period calls for $936 million based on the need for additional wind and solar in rate base and capital spending for a natural gas-fired plant that is expected to replace Hoot Lake Plant when it is retired in 2021. Taking into account the increased capital expenditure plan, our compounded annual growth rate in rate base is projected to be 7.5% over the 2015 to 2021 timeframe.

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2017 through 2021 timeframe.

Our outlook for 2017 is dependent on a variety of factors and is subject to the risks and uncertainties discussed in Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

Our significant accounting policies are described in note 1 to our consolidated financial statements. The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, interim rate refunds, warranty reserves and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the board of directors. The following critical accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements.

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses for our electric utility and corporate employees are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. Further discussion of our pension and postretirement benefit plans and related assumptions is included in note 11 to our consolidated financial statements.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 35 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. Also, a reduction 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 below assumed rates of return or an increase in the anticipated life expectancy of plan participants could result in significant increases 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.

The pension benefit cost for 2017 for our noncontributory funded pension plan is expected to be $5.9 million compared to $5.7 million in 2016, reflecting a decrease in the assumed rate of return on pension plan assets from 7.75% in 2016 to 7.50% in 2017, and a decrease in the estimated discount rate used to determine annual benefit cost accruals from 4.76% in 2016 to 4.60% in 2017. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of "Aa" published by recognized rating agencies, along with bond matching models specific to our plan's cash flows as a basis to determine the rate.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2016, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2016 pension benefit cost by $892,000; a 0.25 decrease in the discount rate would have increased our 2016 pension benefit cost by $937,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2016 pension benefit cost by $521,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2016 pension benefit cost by $509,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2016 pension benefit cost by $628,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase in the discount rate would have decreased our 2016 postretirement medical benefit costs by $197,000. A 0.25 decrease in the discount rate would have increased our 2016 postretirement medical benefit costs by $206,000. See note 11 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

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.

TAXATION

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2016 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of ASC Topic 740, *Income Taxes,* the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

Deferred income taxes are provided for revenue and expenses which are recognized in different periods for income tax and financial reporting purposes. We assess our deferred tax assets for recoverability taking into consideration our historical and anticipated earnings levels, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against our deferred tax assets. As facts and circumstances change, adjustments to the valuation allowance may be required.

ASSET IMPAIRMENT

We are required to test for asset impairment relating to property and equipment whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset may exceed its fair value and not be recoverable. We apply the accounting guidance under ASC 360-10-35, *Property, Plant, and Equipment—Subsequent Measurement,* in order to determine whether or not an asset is impaired. This standard requires an impairment analysis when indicators of impairment are present. If such indicators are present, the standard requires that if the sum of the future expected cash flows from a company's asset, undiscounted and without interest charges, is less than the carrying amount, an asset impairment must be recognized in the financial

statements. The amount of the impairment is the difference between the fair value of the asset and the carrying amount of the asset.

We believe the accounting estimates related to an asset impairment are critical because: (1) they are highly susceptible to change from period to period, reflecting changing business cycles, (2) they require management to make assumptions about future cash flows over future years, and (3) the impact of recognizing an impairment could have a significant effect on operations. Management's assumptions about future cash flows require significant judgment because actual operating levels have fluctuated in the past and are expected to continue to do so in the future.

As of December 31, 2016 an assessment of the carrying amounts of our long-lived assets and other intangibles indicated these assets were not impaired.

GOODWILL IMPAIRMENT

Goodwill is required to be evaluated annually for impairment, according to ASC 350-20-35, *Goodwill—Subsequent Measurement*. We perform quantitative goodwill impairment testing annually in the fourth quarter. In addition, the test is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which our reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

The quantitative goodwill impairment test is a two-step process performed at the reporting unit level. We have determined the reporting units for our goodwill impairment test are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which our chief operating decision makers regularly review the operating results. For more information on our operating segments, see note 2 to consolidated financial statements. The first step of the quantitative impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. At December 31, 2016, the fair value substantially exceeded the carrying value at all our reporting units reported under continuing operations.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the reporting unit's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. We use a discounted cash flow methodology for our income approach. Under this approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. Under the market approach, we estimate fair value using multiples derived from comparable enterprise value to EBITDA multiples, comparable price earnings ratios, comparable enterprise value to sales multiples and if available, comparable sales transactions for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not impairment is indicated.

ACQUISITION METHOD OF ACCOUNTING

We account for acquisitions under the requirements of ASC Topic 805, *Business Combinations*. Under ASC 805 the term "purchase method of accounting" is replaced with "acquisition method of accounting" and requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions.

Acquired assets and liabilities assumed that are subject to critical estimates include property, plant and equipment, intangible assets and inventory. The fair value of property, plant and equipment is based on valuations performed by qualified internal personnel and/or with the assistance of outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase. Intangible assets are identified and valued using the guidelines of ASC 805. The fair value of intangible assets is based on estimates including royalty rates, customer attrition rates and estimated cash flows.

While the allocation of purchase price is subject to a high degree of judgment and uncertainty, we do not expect the estimates to vary significantly once an acquisition is complete. We believe our estimates have been reasonable in the past as there have been no significant valuation adjustments to the allocation of purchase price.

FORWARD-LOOKING INFORMATION—SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the Act). 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 "may," "will," "expect," "anticipate," "continue," "estimate," "project," "believes" or similar expressions are intended to identify forward-looking statements within the meaning of the Act. 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 Annual Report on Form 10-K and in our other SEC filings.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

At December 31, 2016 we had exposure to market risk associated with interest rates because we had $15 million outstanding subject to a variable interest rate that is indexed to 30 day LIBOR plus 90 basis points under the Term Loan Agreement that terminates on February 5, 2018. OTP had $42.9 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under the OTP Credit Agreement.

All of our remaining consolidated long-term debt outstanding on December 31, 2016 has fixed interest rates. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, 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 interest rate swaps to manage net exposure to interest rate changes related to 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.

The companies in our Manufacturing segment are exposed to market risk related to changes in commodity prices for steel, aluminum and polystyrene (PS) and other plastics resins. The price and availability of these raw materials could affect the revenues and earnings of our Manufacturing segment.

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, sales volume has been higher and when resin prices are falling, sales volume has been lower. Operating income may decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

ITEM 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Otter Tail Corporation

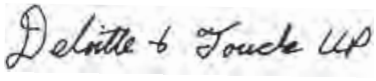
We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Otter Tail Corporation and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.



Minneapolis, Minnesota
February 22, 2017

CONSOLIDATED BALANCE SHEETS, DECEMBER 31

(in thousands)	2016	2015
Assets		
Current Assets		
Cash and Cash Equivalents	**$ —**	$ —
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $1,246 for 2016 and $1,262 for 2015)	**68,242**	62,974
Other	**5,850**	9,073
Inventories	**83,740**	85,416
Unbilled Revenues	**20,080**	17,869
Income Taxes Receivable	**662**	4,000
Regulatory Assets	**21,297**	18,904
Other	**8,144**	8,453
Total Current Assets	**208,015**	206,689
Investments	**8,417**	8,284
Other Assets	**34,104**	32,784
Goodwill	**37,572**	39,732
Other Intangibles–Net	**14,958**	15,673
Regulatory Assets	**132,094**	127,707
Plant		
Electric Plant in Service	**1,860,357**	1,820,763
Nonelectric Operations	**211,826**	201,343
Construction Work in Progress	**153,261**	79,612
Total Gross Plant	**2,225,444**	2,101,718
Less Accumulated Depreciation and Amortization	**748,219**	713,904
Net Plant	**1,477,225**	1,387,814
Total Assets	**$ 1,912,385**	$1,818,683

See accompanying notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEETS, DECEMBER 31

(in thousands, except share data)	2016	2015
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	**$ 42,883**	$ 80,672
Current Maturities of Long-Term Debt	**33,201**	52,422
Accounts Payable	**89,350**	89,499
Accrued Salaries and Wages	**17,497**	16,182
Accrued Taxes	**16,000**	14,827
Other Accrued Liabilities	**15,377**	15,416
Liabilities of Discontinued Operations	**1,363**	2,098
Total Current Liabilities	**215,671**	271,116
Pensions Benefit Liability	**97,627**	104,912
Other Postretirement Benefits Liability	**62,571**	48,730
Other Noncurrent Liabilities	**21,706**	23,854
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	**226,591**	207,669
Deferred Tax Credits	**22,849**	24,506
Regulatory Liabilities	**82,433**	77,432
Other	**7,492**	11,595
Total Deferred Credits	**339,365**	321,202
Capitalization (page 54)		
Long-Term Debt—Net	**505,341**	443,846
Cumulative Preferred Shares—Authorized 1,500,000 Shares Without Par Value; Outstanding—None	**—**	—
Cumulative Preference Shares—Authorized 1,000,000 Shares Without Par Value; Outstanding—None	**—**	—
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2016—39,348,136 Shares; 2015—37,857,186 Shares	**196,741**	189,286
Premium on Common Shares	**337,684**	293,610
Retained Earnings	**139,479**	126,025
Accumulated Other Comprehensive Loss	**(3,800)**	(3,898)
Total Common Equity	**670,104**	605,023
Total Capitalization	**1,175,445**	1,048,869
Total Liabilities and Equity	**$ 1,912,385**	$ 1,818,683

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME—FOR THE YEARS ENDED DECEMBER 31

(in thousands, except per-share amounts)	2016	2015	2014
Operating Revenues			
Electric	**$ 427,349**	$ 407,039	$ 407,629
Product Sales	**376,190**	372,765	391,633
Total Operating Revenues	**803,539**	779,804	799,262
Operating Expenses			
Production Fuel—Electric	**54,792**	42,744	67,216
Purchased Power—Electric System Use	**63,226**	78,150	65,848
Electric Operation and Maintenance Expenses	**151,225**	140,768	141,936
Cost of Products Sold (depreciation included below)	**295,222**	295,032	308,069
Other Nonelectric Expenses	**40,264**	40,021	45,981
Depreciation and Amortization	**73,445**	60,363	58,074
Property Taxes—Electric	**14,266**	13,512	12,607
Total Operating Expenses	**692,440**	670,590	699,731
Operating Income	**111,099**	109,214	99,531
Interest Charges	**31,886**	31,160	29,648
Other Income	**2,905**	2,177	3,557
Income Before Income Taxes—Continuing Operations	**82,118**	80,231	73,440
Income Tax Expense—Continuing Operations	**20,081**	21,642	16,557
Net Income from Continuing Operations	**62,037**	58,589	56,883
Discontinued Operations			
Income (Loss)—net of Income Tax Expense (Benefit) of $138 in 2016, ($1,539) in 2015 and $3,952 in 2014	**284**	(5,404)	6,445
Impairment Loss—net of Income Tax (Benefit) of $0 in 2015 and 2014	**—**	(1,000)	(5,605)
Gain on Disposition—net of Income Tax Expense of $4,530 in 2015	**—**	7,160	—
Net Income from Discontinued Operations	**284**	756	840
Total Net Income	**$ 62,321**	$ 59,345	$ 57,723
Average Number of Common Shares Outstanding—Basic	**38,546**	37,495	36,514
Average Number of Common Shares Outstanding—Diluted	**38,731**	37,668	36,753
Basic Earnings Per Common Share:			
Continuing Operations	**$ 1.61**	$ 1.56	$ 1.56
Discontinued Operations	**$ 0.01**	$ 0.02	$ 0.02
	$ 1.62	$ 1.58	$ 1.58
Diluted Earnings Per Common Share:			
Continuing Operations	**$ 1.60**	$ 1.56	$ 1.55
Discontinued Operations	**$ 0.01**	$ 0.02	$ 0.02
	$ 1.61	$ 1.58	$ 1.57
Dividends Declared Per Common Share	**$ 1.25**	$ 1.23	$ 1.21

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME–FOR THE YEARS ENDED DECEMBER 31

(in thousands)	2016	2015	2014
Net Income	**$ 62,321**	$ 59,345	$ 57,723
Other Comprehensive Income (Loss):			
Unrealized Loss on Available-for-Sale Securities:			
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	**(3)**	(3)	(19)
Losses Arising During Period	**(14)**	(49)	(14)
Income Tax Benefit	**6**	18	12
Change in Unrealized Losses on Available-for-Sale Securities—net-of-tax	**(11)**	(34)	(21)
Pension and Postretirement Benefit Plans:			
Actuarial (Losses) Gains Net of Regulatory Allocation Adjustment	**(445)**	510	(5,048)
Amortization of Unrecognized Postretirement Benefit Costs (note 11)	**628**	821	192
Income Tax (Expense) Benefit	**(74)**	(532)	1,942
Pension and Postretirement Benefit Plans—net-of-tax	**109**	799	(2,914)
Total Other Comprehensive Income (Loss)	**98**	765	(2,935)
Total Comprehensive Income	**$ 62,419**	$ 60,110	$ 54,788

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(in thousands, except common shares outstanding)	Common Shares Outstanding	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
Balance, December 31, 2013	**36,271,696**	**$ 181,358**	**$ 255,759**	**$ 99,441**	**$ (1,728)**(a)	**$ 534,830**
Common Stock Issuances, Net of Expenses	971,286	4,857	21,057			25,914
Common Stock Retirements	(24,929)	(125)	(465)			(590)
Net Income				57,723		57,723
Other Comprehensive Loss					(2,935)	(2,935)
Tax Benefit—Stock Compensation			302			302
Employee Stock Incentive Plan Expense			1,783			1,783
Common Dividends ($1.21 per share)				(44,261)		(44,261)
Balance, December 31, 2014	**37,218,053**	**$ 186,090**	**$ 278,436**	**$ 112,903**	**$ (4,663)**(a)	**$ 572,766**
Common Stock Issuances, Net of Expenses	690,485	3,453	14,715			18,168
Common Stock Retirements	(51,352)	(257)	(1,339)			(1,596)
Net Income				59,345		59,345
Other Comprehensive Income					765	765
Tax Benefit—Stock Compensation			82			82
Employee Stock Incentive Plan Expense			1,716			1,716
Common Dividends ($1.23 per share)				(46,223)		(46,223)
Balance, December 31, 2015	**37,857,186**	**$ 189,286**	**$ 293,610**	**$ 126,025**	**$ (3,898)**(a)	**$ 605,023**
Common Stock Issuances, Net of Expenses	1,494,618	7,473	38,490			45,963
Common Stock Retirements	(3,668)	(18)	(86)			(104)
Net Income				62,321		62,321
Other Comprehensive Income					98	98
Employee Stock Incentive Plan Expense			3,178			3,178
ASU 2016-09 Adoption			2,492	(623)		1,869
Common Dividends ($1.25 per share)				(48,244)		(48,244)
Balance, December 31, 2016	**39,348,136**	**$ 196,741**	**$ 337,684**	**$ 139,479**	**$ (3,800)**(a)	**$ 670,104**

(a) Accumulated Other Comprehensive Loss on December 31 is comprised of the following:

(in thousands)	2016	2015	2014
Unrealized (Loss) Gain on Marketable Equity Securities:			
Before Tax	$ (29)	$ (12)	$ 40
Tax Effect	10	4	(14)
Unrealized (Loss) Gain on Marketable Equity Securities—net-of-tax	(19)	(8)	26
Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits:			
Before Tax	(6,300)	(6,484)	(7,815)
Tax Effect	2,519	2,594	3,126
Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits—net-of-tax	(3,781)	(3,890)	(4,689)
Accumulated Other Comprehensive Loss:			
Before Tax	(6,329)	(6,496)	(7,775)
Tax Effect	2,529	2,598	3,112
Net Accumulated Other Comprehensive Loss	$ (3,800)	$ (3,898)	$ (4,663)

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS—FOR THE YEARS ENDED DECEMBER 31

(in thousands)	2016	2015	2014
Cash Flows from Operating Activities			
Net Income	**$ 62,321**	$ 59,345	$ 57,723
Adjustments to Reconcile Net Income			
to Net Cash Provided by Operating Activities:			
Net Gain from Sale of Discontinued Operations	**—**	(7,160)	—
Net (Income) Loss from Discontinued Operations	**(284)**	6,404	(840)
Depreciation and Amortization	**73,445**	60,363	58,074
Deferred Tax Credits	**(1,657)**	(1,878)	(1,904)
Deferred Income Taxes	**19,124**	26,027	28,204
Change in Deferred Debits and Other Assets	**(10,090)**	11,407	(50,361)
Discretionary Contribution to Pension Fund	**(10,000)**	(10,000)	(20,000)
Change in Noncurrent Liabilities and Deferred Credits	**14,685**	20,524	58,442
Allowance for Equity/Other Funds Used During Construction	**(857)**	(1,303)	(1,543)
Change in Derivatives Net of Regulatory Deferral	**—**	(14,736)	519
Stock Compensation Expense—Equity Awards	**3,178**	1,716	1,783
Other—Net	**7**	(80)	601
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	**(944)**	(1,746)	(4,647)
Change in Inventories	**1,874**	1,960	(12,577)
Change in Other Current Assets	**(2,541)**	(210)	(579)
Change in Payables and Other Current Liabilities	**11,941**	(15,150)	10,296
Change in Interest Payable and Income Taxes Receivable/Payable	**3,339**	(3,943)	2,578
Net Cash Provided by Continuing Operations	**163,541**	131,540	125,769
Net Cash Used in Discontinued Operations	**(155)**	(14,000)	(13,295)
Net Cash Provided by Operating Activities	**163,386**	117,540	112,474
Cash Flows from Investing Activities			
Capital Expenditures	**(161,259)**	(160,084)	(163,582)
Proceeds from Disposal of Noncurrent Assets	**4,837**	3,590	2,467
Acquisition Purchase Price Cash Received (Paid)	**1,500**	(30,806)	—
Cash Used for Investments and Other Assets	**(4,402)**	(6,302)	(2,785)
Net Cash Used in Investing Activities—Continuing Operations	**(159,324)**	(193,602)	(163,900)
Net Proceeds from Sale of Discontinued Operations	**—**	39,401	—
Net Cash Used in Investing Activities—Discontinued Operations	**—**	(1,769)	(596)
Net Cash Used in Investing Activities	**(159,324)**	(155,970)	(164,496)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**(3,363)**	2,857	1,236
Net Short-Term (Repayments) Borrowings	**(37,789)**	69,818	(40,341)
Proceeds from Issuance of Common Stock	**44,435**	14,233	26,259
Common Stock Issuance Expenses	**(562)**	(451)	(673)
Payments for Retirement of Capital Stock	**(104)**	(1,596)	(590)
Proceeds from Issuance of Long-Term Debt	**130,000**	—	150,000
Short-Term and Long-Term Debt Issuance Expenses	**(888)**	(312)	(856)
Payments for Retirement of Long-Term Debt	**(87,547)**	(212)	(41,088)
Dividends Paid and Other Distributions	**(48,244)**	(46,223)	(44,261)
Net Cash (Used in) Provided by Financing Activities—Continuing Operations	**(4,062)**	38,114	49,686
Net Cash Provided by Financing Activities—Discontinued Operations	**—**	316	1,178
Net Cash (Used in) Provided by Financing Activities	**(4,062)**	38,430	50,864
Net Change in Cash and Cash Equivalents—Discontinued Operations	**—**	—	(849)
Net Change in Cash and Cash Equivalents	**—**	—	(2,007)
Cash and Cash Equivalents at Beginning of Period	**—**	—	2,007
Cash and Cash Equivalents at End of Period	**$ —**	$ —	$ —

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION, DECEMBER 31

(in thousands, except share data)	2016	2015
Short-Term Debt		
Otter Tail Corporation Credit Agreement	**$ —**	$ 59,666
Otter Tail Power Company Credit Agreement	**42,883**	21,006
Total Short-Term Debt	**$ 42,883**	$ 80,672
Long-Term Debt		
Obligations of Otter Tail Corporation		
9.000% Notes, due December 15, 2016	**$ —**	$ 52,330
Term Loan, LIBOR plus 0.90%, due February 5, 2018	**15,000**	—
3.55% Guaranteed Senior Notes, due December 15, 2026	**80,000**	—
North Dakota Development Note, 3.95%, due April 1, 2018	**106**	182
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	**836**	977
Total—Otter Tail Corporation	**95,942**	53,489
Less: Current Maturities—net of Unamortized Debt Issuance Costs	**231**	52,422
Unamortized Long-Term Debt Issuance Costs	**539**	122
Total Otter Tail Corporation Long-Term Debt net of Unamortized Debt Issuance Costs	**95,172**	945
Obligations of Otter Tail Power Company		
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	**33,000**	33,000
Senior Unsecured Notes 4.63%, due December 1, 2021	**140,000**	140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	**30,000**	30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	**42,000**	42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	**60,000**	60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	**50,000**	50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	**90,000**	90,000
Total—Otter Tail Power Company	**445,000**	445,000
Less: Current Maturities—net of Unamortized Debt Issuance Costs	**32,970**	—
Unamortized Long-Term Debt Issuance Costs	**1,861**	2,099
Total Otter Tail Power Company Long-Term Debt net of Unamortized Debt Issuance Costs	**410,169**	442,901
Total Consolidated Long-Term Debt	**540,942**	498,489
Less: Current Maturities—net of Unamortized Debt Issuance Costs	**33,201**	52,422
Unamortized Long-Term Debt Issuance Costs	**2,400**	2,221
Total Consolidated Long-Term Debt net of Unamortized Debt Issuance Costs	**505,341**	443,846
Cumulative Preferred Shares—Without Par Value, Authorized 1,500,000 Shares; Outstanding: None		
Cumulative Preference Shares–Without Par Value, Authorized 1,000,000 Shares; Outstanding: None		
Total Common Shareholders' Equity	**670,104**	605,023
Total Capitalization	**$ 1,175,445**	$1,048,869

See accompanying notes to consolidated financial statements.

1. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements of Otter Tail Corporation and its wholly owned subsidiaries (the Company) include the accounts of the following segments: Electric, Manufacturing and Plastics. See note 2 to consolidated financial statements for further descriptions of the Company's business segments. All intercompany balances and transactions have been eliminated in consolidation except profits on sales to the regulated electric utility company from nonregulated affiliates, which is in accordance with the requirements of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 980, *Regulated Operations* (ASC 980).

Regulation and ASC 980

The Company's regulated electric utility company, Otter Tail Power Company (OTP), accounts for the financial effects of regulation in accordance with ASC 980. This standard allows for the recording of a regulatory asset or liability for costs and revenues that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, OTP defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 4 to consolidated financial statements for further discussion.

OTP is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonelectric businesses.

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $495,000 in 2016, $723,000 in 2015 and $689,000 in 2014. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties (5 to 82 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.88% in 2016, 2.61% in 2015 and 2.89% in 2014. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination, and are depreciated on a straight-line basis over the assets' estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. No interest was capitalized on nonelectric plant in 2016, 2015 or 2014. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

Recoverability of Long-Lived Assets

The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying amount of the assets with 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, the Company would recognize an impairment loss. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

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 three major in-service transmission lines and two additional major transmission lines under construction. The following table provides OTP's ownership percentages and amounts included in the Company's December 31, 2016 and 2015 consolidated balance sheets for OTP's share of jointly owned assets in each of these jointly owned facilities:

Jointly Owned Facilities *(dollars in thousands)*	**OTP Ownership Percentage**	**Electric Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**	**Net Plant**
December 31, 2016					
Big Stone Plant	**53.9%**	**$ 328,809**	**$ 23**	**$ (65,665)**	**$ 263,167**
Coyote Station	**35.0%**	**176,315**	**113**	**(101,499)**	**74,929**
Fargo-Monticello 345 kV line	**14.2%**	**78,298**	**—**	**(3,511)**	**74,787**
Brookings-Southeast Twin Cities 345 kV line *(1)*	**4.8%**	**26,406**	**—**	**(924)**	**25,482**
Bemidji-Grand Rapids 230 kV line	**14.8%**	**16,331**	**—**	**(1,573)**	**14,758**
Big Stone South to Brookings 345kV line *(1)*	**50.0%**	**—**	**45,050**	**—**	**45,050**
Big Stone South to Ellendale 345 kV line *(1)*	**50.0%**	**—**	**49,160**	**—**	**49,160**
December 31, 2015					
Big Stone Plant	53.9%	$ 327,474	$ (305)	$ (57,641)	$ 269,528
Coyote Station	35.0%	165,497	7,405	(103,822)	69,080
Fargo-Monticello 345 kV line	14.2%	78,272	—	(2,213)	76,059
Brookings-Southeast Twin Cities 345 kV line *(1)*	4.8%	26,189	—	(486)	25,703
Bemidji-Grand Rapids 230 kV line	14.8%	16,331	—	(1,233)	15,098
Big Stone South to Brookings 345kV line *(1)*	50.0%	—	14,210	—	14,210
Big Stone South to Ellendale 345 kV line *(1)*	50.0%	—	8,335	—	8,335

(1) Midcontinent Independent System Operator, Inc. (MISO) Multi-Value Project (MVP) designation provides for a return on invested funds while under construction under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).

The Company's share of direct revenue and expenses of the jointly owned facilities is included in operating revenue and expenses in the consolidated statements of income.

Coyote Station Lignite Supply Agreement—Variable Interest Entity—In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (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 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 also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets 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 in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE and the Company is not required to include CCMC in its consolidated financial statements.

If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) 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. Coyote Station started taking delivery of coal and paying for coal and accumulated development fees and capital charges under the LSA in May 2016. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of December 31, 2016 could be as high as $60.6 million, OTP's 35% share of unrecovered costs.

Income Taxes

Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes investment tax credits over the estimated lives of related property. The Company records income taxes in accordance with ASC Topic 740, *Income Taxes*, and has recognized in its consolidated financial statements 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. The term "more-likely-than-not" means a likelihood of more than 50%. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 14 to consolidated financial statements regarding the Company's accounting for uncertain tax positions.

The Company also is required to assess the realizability of its deferred tax assets, taking into consideration the Company's forecast of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, valuation allowances against the Company's deferred tax assets. To the extent facts and circumstances change in the future, adjustments to the valuation allowance may be required.

Revenue Recognition

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, the price is fixed or determinable and collectability is reasonably assured. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as OTP's 2015 forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with ASC Topic 815, *Derivatives and Hedging* (ASC 815). Gains and losses on forward energy contracts subject to regulatory treatment, if any, have been deferred and recognized on a net basis in revenue in the period realized.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Customer electricity use is metered and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment, under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is recognized for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the fuel clause adjustment, for conservation program incentives and bonuses earned but not yet billed and for renewable resource, transmission-related and environmental incurred costs and investment returns approved for recovery through riders.

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered. For shared use of transmission facilities with certain regional transmission cooperatives, revenues are estimated. Bills are rendered based on anticipated usage and settlements are made later based on actual usage. Estimated revenues may be adjusted prior to settlement, or at the time of settlement, to reflect actual usage.

Under ASC 815, OTP accounts for forward energy contracts as derivatives subject to mark-to-market accounting unless those contracts meet the definition of a capacity contract or are not subject to unplanned netting, then OTP accounts for the contracts under the normal purchases and sales exception to mark-to-market accounting.

Manufacturing and Plastics operating revenues are recorded when products are shipped.

Warranty Reserves

Certain products sold by the Company's manufacturing and plastics companies carry product warranties for one year after the shipment date. These companies' standard product warranty terms generally

include post-sales support and repairs or replacement of a product at no additional charge for a specified period of time. While these companies engage in extensive product quality programs and processes, including actively monitoring and evaluating the quality of their component suppliers, they base their estimated warranty obligations on warranty terms, ongoing product failure rates, repair costs, product call rates, average cost per call, and current period product shipments. The Company's manufacturing and plastics companies have not incurred any significant warranty costs over the last three fiscal years in continuing operations.

Shipping and Handling Costs
The Company includes revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold.

Use of Estimates
The Company uses 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.

Cash Equivalents
The Company considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

Investments
The following table provides a breakdown of the Company's investments at December 31:

(in thousands)	2016	2015
Cost Method:		
Economic Development Loan Pools	$ 54	$ 81
Other	115	2,088
Equity Method Partnerships	23	22
Marketable Securities Classified as Available-for-Sale	8,225	8,093
Total Investments	$ 8,417	$ 10,284
Less: Aevenia, Inc. (AEV, Inc.) Escrow Funds Reported Under Other Current Assets	—	(1,500)
Foley Company (Foley) Escrow Funds Reported Under Other Current Assets	—	(500)
Investments	$ 8,417	$ 8,284

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their fair values on December 31, 2016. See further discussion below.

Agreements Subject to Legally Enforceable Netting Arrangements
The Company does not offset assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet.

Fair Value Measurements
The Company follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

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 by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange (NYMEX).

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.

The following tables present, for each of the hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2016 and December 31, 2015:

December 31, 2016 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Corporate Debt Securities—Held by Captive Insurance Company		$ 5,280	
Government-Backed and Government-Sponsored Enterprises' Debt Securities—Held by Captive Insurance Company		2,945	
Other Assets:			
Money Market and Mutual Funds—Nonqualified Retirement Savings Plan	$ 849		
Total Assets	$ 849	$ 8,225	

December 31, 2015 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Current Assets—Other:			
Money Market Escrow Accounts—AEV, Inc. and Foley Company Dispositions	$ 2,000		
Investments:			
Government-Backed and Government-Sponsored Enterprises' Debt Securities—Held by Captive Insurance Company		$ 4,235	
Corporate Debt Securities—Held by Captive Insurance Company		3,858	
Other Assets:			
Money Market and Mutual Funds—Nonqualified Retirement Savings Plan	196		
Total Assets	$ 2,196	$ 8,093	
Liabilities:			
Other Accrued Liabilities:			
Derivative Liabilities—Forward Gasoline Purchase Contracts		$ 199	
Total Liabilities		$ 199	

The valuation techniques and inputs used for the Level 2 fair value measurements in the table above are as follows:

Forward Gasoline Purchase Contracts—These contracts were priced based on NYMEX quoted prices for Reformulated Blendstock for Oxygenate Blending (RBOB) Gasoline contracts. Prices used for the fair valuation of these contracts are based on NYMEX daily reporting date quoted prices for RBOB contracts with the same settlement periods. As of December 31, 2016 OTP held, and currently holds, no RBOB contracts.

Government-Backed and Government-Sponsored Enterprises' and Corporate Debt Securities Held by the Company's Captive Insurance Company—Fair values are determined on the basis of valuations provided by a third-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service may be based on broker quotes.

Inventories

Electric segment inventories are reported at average cost. The Manufacturing and Plastics segments' inventories are stated at the lower of average cost or market. Inventories consist of the following at December 31:

(in thousands)	2016	2015
Finished Goods	**$ 27,755**	$ 25,971
Work in Process	**11,754**	12,821
Raw Material, Fuel and Supplies	**44,231**	46,624
Total Inventories	**$ 83,740**	$ 85,416

Goodwill and Other Intangible Assets

The Company accounts for goodwill and other intangible assets in accordance with the requirements of ASC Topic 350, *Intangibles—Goodwill and Other*, measuring its goodwill for impairment annually in the fourth quarter, and more often when events indicate the assets may be impaired. The Company does qualitative assessments of its reporting units with recorded goodwill to determine if it is more likely than not that the fair value of the reporting unit exceeds its book value. The Company also does quantitative assessments of its reporting units with recorded goodwill to determine the fair value of the reporting unit.

In the fourth quarter of 2014 the Company entered into negotiations to sell Foley and, as a result of an impairment indicator, the Company recorded a $5.6 million goodwill impairment charge. This impairment charge was based on the indicated offering price in a signed letter of intent for the purchase of Foley. In the first quarter of 2015, Foley recorded an additional $1.0 million goodwill impairment charge based on adjustments to the carrying value of Foley. The fourth quarter 2014 and first quarter 2015 goodwill impairment losses are reflected in the results of discontinued operations. See note 16 to consolidated financial statements.

On September 1, 2015 Miller Welding & Iron Works, Inc. (BTD-Illinois), a wholly owned subsidiary of BTD Manufacturing, Inc. (BTD), acquired the assets of Impulse Manufacturing, Inc. (Impulse) of Dawsonville, Georgia. The acquired business operates under the name BTD-Georgia. Based on the preliminary purchase price allocation, the difference in the fair value of assets acquired and the price paid for Impulse resulted in an initial estimate of acquired goodwill of $8.2 million. A final determination of the purchase price was agreed to in June 2016 resulting in a $2.2 million reduction in acquired goodwill in June 2016. See note 2 to the Company's consolidated financial statements for more information.

The following tables summarize changes to goodwill by business segment during 2016 and 2015:

(in thousands)	Gross Balance December 31, 2015	Accumulated Impairments	Balance (net of impairments) December 31, 2015	Adjustments to Goodwill in 2016	Balance (net of impairments) December 31, 2016
Manufacturing	$ 20,430	$ —	$ 20,430	**$ (2,160)**	**$ 18,270**
Plastics	19,302	—	19,302	**—**	**19,302**
Total	$ 39,732	$ —	$ 39,732	**$ (2,160)**	**$ 37,572**

(in thousands)	Gross Balance December 31, 2014	Accumulated Impairments	Balance (net of impairments) December 31, 2014	Adjustments and Additions to Goodwill in 2015	Balance (net of impairments) December 31, 2015
Manufacturing	$ 12,186	$ —	$ 12,186	$ 8,244	$ 20,430
Plastics	19,302	—	19,302	—	19,302
Total	$ 31,488	$ —	$ 31,488	$ 8,244	$ 39,732

Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC Topic 360-10-35, *Property, Plant, and Equipment—Overall—Subsequent Measurement.* With the purchase of BTD-Georgia on September 1, 2015, the Company acquired customer relationships valued at $4,870,000 to be amortized over 20 years and the seller entered into a covenant not to compete valued at $620,000 to be amortized over three years. The final purchase price adjustment agreed to in June 2016 resulted in an $810,000 increase in the fair value of acquired customer relationships and a $30,000 reduction in the fair value of the covenant not to compete. The changes in the value of these intangibles had an insignificant impact on the Company's consolidated net income in 2016 related to a change in amortization expense that would have been recorded in 2015 had the adjusted asset values been established on acquisition in 2015. See note 2 to the Company's consolidated financial statements for more information.

The following table summarizes the components of the Company's intangible assets at December 31, 2016 and December 31, 2015:

December 31, 2016 *(in thousands)*	**Gross Carrying Amount**	**Accumulated Amortization**	**Net Carrying Amount**	**Remaining Amortization Periods**
Amortizable Intangible Assets:				
Customer Relationships	**$22,491**	**$ 7,861**	**$14,630**	**36-224 months**
Covenant not to Compete	**590**	**262**	**328**	**20 months**
Total	**$23,081**	**$ 8,123**	**$14,958**	
December 31, 2015 *(in thousands)*				
Amortizable Intangible Assets:				
Customer Relationships	$21,681	$ 6,714	$14,967	48-236 months
Covenant not to Compete	620	69	551	32 months
Other Intangible Assets	639	543	96	9 months
Emission Allowances	59	NA	59	Expensed as used
Total	$22,999	$ 7,326	$15,673	

The amortization expense for these intangible assets was:

(in thousands)	**2016**	2015	2014
Amortization Expense—Intangible Assets	$1,436	$1,127	$ 977

The estimated annual amortization expense for these intangible assets for the next five years is:

(in thousands)	2017	2018	2019	2020	2021
Estimated Amortization Expense—Intangible Assets	$ 1,330	$ 1,264	$ 1,133	$ 1,099	$ 1,099

Supplemental Disclosures of Cash Flow Information

	As of December 31,	
(in thousands)	**2016**	2015
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	**$ 13,533**	$ 20,371

(in thousands)	**2016**	2015	2014
Cash Paid (Received) During the Year for:			
Interest (net of amount capitalized)	**$ 31,269**	$ 30,512	$ 26,364
Income Taxes	**$ (1,291)**	$ 7,322	$ 145

New Accounting Standards

Accounting Standards Update (ASU) 2014-09—In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Amendments to the ASC in ASU 2014-09, as amended, are effective for fiscal years beginning after December 15, 2017. Early adoption is permitted, but not any earlier than January 1, 2017. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. As of December 31, 2016 the Company has reviewed its revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and is evaluating transition options. Based on review of the Company's revenue streams, the Company does not anticipate a significant change in the levels or timing of revenue recognition over an annual or interim period as a result of the adoption of ASU 2014-09, with the exception of the treatment of contributions in aid of construction in the Electric segment on which consensus treatment has not been determined and guidance has not been provided. Currently, the Company reduces its investment in fixed assets for the amount of these contributions. Should the Company be required to recognize these contributions as revenue under ASU 2014-09, it could result in a significant increase in reported revenues and expenses. Adoption of ASU 2014-09 will result in additional disclosures related to the nature, timing and certainty of revenues and any contract assets or liabilities that may be required to be reported under the updated standard. The Company does not plan to adopt the updated guidance prior to January 1, 2018.

ASU 2015-03—In April 2015, the FASB issued ASU No. 2015-03, *Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03), which requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 is effective for interim and annual reporting periods beginning after December 15, 2015 and must be applied retrospectively to balance sheets presented for periods prior to adoption. The Company adopted the updated standards in ASU 2015-03 in the first quarter of 2016. In conjunction with implementing this update, the Company is reclassifying the remaining balance of unamortized line of credit issuance costs from the deferred debit section of its consolidated balance sheet to other assets, eliminating the deferred debits section of its consolidated balance sheet and displaying long-term regulatory assets as a separate line item on its consolidated balance sheet. The effects of applying the guidance in ASU 2015-03 retrospectively to the Company's December 31, 2015 consolidated balance sheet and statement of capitalization and of the

associated reclassification of unamortized line of credit issuance costs are shown in the following table:

(in thousands)	December 31, 2015 Previously Stated	Adjustments	December 31, 2015 Adjusted
Other Assets	$ 31,108	$ 1,676	$ 32,784
Unamortized Debt Expense	3,897	(3,897)	—
Total Assets	1,820,904	(2,221)	1,818,683
Current Liabilities			
Current Maturities of Long-Term Debt	52,544	(122)	52,422
Total Current Liabilities	271,238	(122)	271,116
Capitalization			
Long-Term Debt—Net	445,945	(2,099)	443,846
Total Capitalization	1,050,968	(2,099)	1,048,869
Total Liabilities and Equity	1,820,904	(2,221)	1,818,683

ASU 2015-11—In July 2015, the FASB issued ASU No. 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory*, which requires that inventories be measured at the lower of cost or net realizable value instead of the lower of cost or market value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The standards update is effective prospectively for fiscal years and interim periods beginning after December 15, 2016, with early adoption permitted. The Company does not expect the adoption of the updated standard to have a material impact on its consolidated financial statements.

ASU 2015-16—In September 2015, the FASB issued ASU No. 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments* (ASU 2015-16), which requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in ASU 2015-16 require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments in ASU 2015-16 are effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years and should be applied prospectively to adjustments to provisional amounts that occur after the effective date, with earlier application permitted for financial statements that have not been issued. The Company elected to adopt the updated standard in the fourth quarter of 2015 in order to apply the updates to its recent acquisition of BTD-Georgia. Adoption of the updated standard did not have a material impact on the Company's consolidated financial statements. The early adoption of the standard alleviated the need for prior period adjustments of income related to the BTD-Georgia acquisition purchase price adjustment recorded in June 2016. See note 2 to the Company's consolidated financial statements for more information.

ASU 2016-02—In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. The Company is currently reviewing ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and evaluating transition options. The Company does not currently plan to apply the amendments in ASU 2016-02 to its consolidated financial statements prior to 2019.

ASU 2016-09—In March 2016, the FASB issued ASU No. 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09), which is intended to improve and simplify accounting and reporting requirements related to stock-based compensation programs. The amendments in ASU 2016-09 change how companies account for certain aspects of share-based payments to employees, including: (1) changing award classifications from liability to equity as a result of an increase in the permitted level of share withholding to cover income taxes to satisfy statutory income tax withholding requirements on the awards, (2) recognizing excess tax benefits as an adjustment to income tax expense when the awards vest rather than directly adjusting stockholders' equity, and (3) introducing an accounting policy election that permits reporting entities to elect to account for forfeitures as they occur. The amendments in ASU 2016-09 are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods, with early adoption permitted.

In the fourth quarter of 2016, the Company elected to early adopt the updates in ASU 2016-09. The withholding provisions in the award agreements applicable to the Company's outstanding performance awards granted to executive officers in 2014, 2015 and 2016 allow for withholding up to the maximum statutory tax rates in the applicable jurisdictions. The updates in ASU 2016-09 result in these awards being classified as equity awards rather than liability awards, requiring the amount of expense recognized for these awards to be based on the grant-date fair value of the awards rather than the reporting-date fair value of the awards. The reporting-date fair values of the 2014 and 2015 awards outstanding on December 31, 2015 were less than the grant-date fair values of the awards. On adoption of the updates in ASU 2016-09 in the fourth quarter of 2016, the difference in expense that would have been recognized related to the outstanding 2014 and 2015 awards in 2014 and 2015 had the awards been classified as equity awards instead of liability awards results in a cumulative-effect net-of-tax adjustment to retained earnings of $623,000, with related adjustments to unvested restricted stock liability, deferred tax and miscellaneous paid-in capital accounts, effective as of January 1, 2016, as illustrated below:

Balance Sheet Account Affected, Effective January 1, 2016	Debit	Credit
Adjustment to Retained Earnings	$ 623,000	
Long-Term Incentive Payable	$ 1,453,000	
Deferred Taxes	$ 416,000	
Miscellaneous Paid-In Capital		$ 2,492,000

The impact of adopting the updates in ASU 2016-09 effective January 1, 2016 on 2016 interim reporting periods was not material.

2. Business Combinations, Dispositions and Segment Information

Business Combinations

On September 1, 2015 BTD-Illinois, a wholly owned subsidiary of BTD, acquired the assets of Impulse of Dawsonville, Georgia for $30.8 million in cash. A post-closing reduction in the purchase price of $1.5 million was agreed to in June 2016 resulting in an adjusted purchase price of $29.3 million. The acquired business, operating under the name BTD-Georgia, is a full-service metal fabricator located 30 miles north of Atlanta, Georgia, which offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers. In addition to serving some of BTD's existing customers from a location closer to the customers' manufacturing facilities, this acquisition provides opportunities for growth in new and existing markets for BTD with complementing production capabilities that expand the capacity of services offered by BTD. Pro forma results of operations have not been presented for this acquisition because the effect of the acquisition was not material to the Company.

Below is condensed balance sheet information disclosing the final allocation of the purchase price assigned to each major asset and liability category of BTD-Georgia:

(in thousands)	
Assets:	
Current Assets	$ 4,906
Goodwill	6,083
Other Intangible Assets	6,270
Other Amortizable Assets	1,380
Fixed Assets	13,649
Total Assets	$ 32,288
Liabilities:	
Current Liabilities	$ 2,971
Lease Obligation	11
Total Liabilities	$ 2,982
Cash Paid	$ 29,306

In the fourth quarter of 2015, the Company elected to early adopt ASU No. 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*, which requires that an acquirer in a business combination recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The purchase price adjustment agreed to in June 2016 resulted in a $2.2 million reduction to the value of acquired goodwill, a $0.8 million increase in the fair value of acquired customer relationships and a $0.1 million increase in acquired liabilities. The changes in the value of customer relationships had an immaterial impact on the Company's consolidated net income in 2016 related to a change in amortization expense that would have been recorded in 2015 had the adjusted asset values been established on acquisition in 2015.

The Company acquired no new businesses in 2016 or 2014.

In execution of the Company's announced strategy of realigning its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations, the Company sold several of its holdings in recent years. On December 31, 2014 the Company was in the process of negotiating the sales of Foley, its mechanical and prime contractor on industrial projects, and AEV, Inc., its electrical design and construction services company, which resulted in the removal of its Construction segment from continuing operations. The sale of Foley closed on April 30, 2015 and the sale of the assets of AEV, Inc. closed on February 28, 2015.

The results of operations of the Company's recently disposed businesses are reported as discontinued operations in the Company's consolidated financial statements as of and for the years ended December 31, 2016, 2015 and 2014, and are summarized in note 16 to consolidated financial statements.

Segment Information

The accounting policies of the segments are described under note 1—Summary of Significant Accounting Policies. The Company's business structure currently includes the following three segments: Electric, Manufacturing and Plastics. The chart below indicates the companies included in each segment.

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

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 Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping, fabrication and painting, and production of material and handling trays and horticultural containers. 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 upper Midwest and Southwest regions of the United States.

OTP is a wholly owned subsidiary of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar). The Company's corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

No single customer accounted for over 10% of the Company's consolidated revenues in 2016, 2015 and 2014. All of the Company's long-lived assets are within the United States and sales within the United States accounted for 98.6% of sales in 2016, 97.1% of sales in 2015 and 95.9% of sales in 2014.

The Company evaluates the performance of its business segments and allocates resources to them based on segment net income contribution and return on total invested capital. Information on

continuing operations for the business segments for 2016, 2015 and 2014 is presented in the following table:

(in thousands)	2016	2015	2014
Operating Revenue			
Electric	**$ 427,383**	$ 407,131	$ 407,743
Manufacturing	**221,289**	215,011	219,583
Plastics	**154,901**	157,758	172,050
Intersegment Eliminations	**(34)**	(96)	(114)
Total	**$ 803,539**	$ 779,804	$ 799,262
Cost of Products Sold			
Manufacturing	**$ 171,732**	$ 171,956	$ 169,033
Plastics	**123,496**	123,085	139,081
Intersegment Eliminations	**(6)**	(9)	(45)
Total	**$ 295,222**	$ 295,032	$ 308,069
Other Nonelectric Expenses			
Manufacturing	**$ 21,994**	$ 21,115	$ 23,340
Plastics	**9,402**	9,850	9,292
Corporate	**8,896**	9,143	13,418
Intersegment Eliminations	**(28)**	(87)	(69)
Total	**$ 40,264**	$ 40,021	$ 45,981
Depreciation and Amortization			
Electric	**$ 53,743**	$ 44,786	$ 44,076
Manufacturing	**15,794**	11,853	10,518
Plastics	**3,861**	3,552	3,364
Corporate	**47**	172	116
Total	**$ 73,445**	$ 60,363	$ 58,074
Operating Income (Loss)			
Electric	**$ 90,131**	$ 87,171	$ 76,060
Manufacturing	**11,769**	10,086	16,692
Plastics	**18,142**	21,272	20,313
Corporate	**(8,943)**	(9,315)	(13,534)
Total	**$ 111,099**	$ 109,214	$ 99,531
Interest Charges			
Electric	**$ 25,069**	$ 24,371	$ 23,322
Manufacturing	**3,859**	3,560	3,243
Plastics	**1,034**	1,026	1,043
Corporate and Intersegment Eliminations	**1,924**	2,203	2,040
Total	**$ 31,886**	$ 31,160	$ 29,648
Income Tax Expense (Benefit)—Continuing Operations			
Electric	**$ 16,366**	$ 16,067	$ 11,029
Manufacturing	**2,276**	2,299	4,117
Plastics	**6,538**	8,187	7,301
Corporate	**(5,099)**	(4,911)	(5,890)
Total	**$ 20,081**	$ 21,642	$ 16,557
Net Income (Loss)			
Electric	**$ 49,829**	$ 48,370	$ 43,684
Manufacturing	**5,694**	4,247	9,361
Plastics	**10,628**	12,108	12,085
Corporate	**(4,114)**	(6,136)	(8,247)
Discontinued Operations	**284**	756	840
Total	**$ 62,321**	$ 59,345	$ 57,723
Capital Expenditures			
Electric	**$ 149,648**	$ 135,572	$ 148,719
Manufacturing	**8,429**	20,295	11,252
Plastics	**3,085**	4,206	3,567
Corporate	**97**	11	44
Total	**$ 161,259**	$ 160,084	$ 163,582
Identifiable Assets			
Electric	**$1,622,231**	$1,520,887	$1,438,791
Manufacturing	**166,525**	173,860	128,608
Plastics	**84,592**	81,624	86,650
Corporate	**39,037**	42,312	36,508
Assets of Discontinued Operations	**—**	—	47,559
Total	**$1,912,385**	$1,818,683	$1,738,116

3. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects and use of reagents and emission allowances that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP's revenues in 2016, 2015 and 2014.

MAJOR CAPITAL EXPENDITURE PROJECTS

The Big Stone South—Brookings MVP and CapX2020 Project— This 345 kiloVolt (kV) transmission line, currently under construction, will extend approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power—MN (NSP MN), a subsidiary of Xcel Energy Inc., jointly developed this project and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the third quarter of 2015 and the line is expected to be in service in fall 2017.

The Big Stone South—Ellendale MVP—This is a 345 kV transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (MDU), and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019.

Capacity Expansion 2020 (CapX2020) Transmission Line Projects— CapX2020 is a joint initiative of eleven investor-owned, cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service.

Fargo–Monticello 345 kV CapX2020 Project (the Fargo Project)—OTP has invested approximately $81 million and has a 14.2% ownership interest in the jointly-owned assets of this 240-mile transmission line, and owns 100% of certain assets of the project. The final phase of this project was energized on April 2, 2015.

Brookings–Southeast Twin Cities 345 kV CapX2020 Project (the Brookings Project)—OTP has invested approximately $26 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. The final segments of this line were energized on March 26, 2015.

Big Stone Plant Air Quality Control System (AQCS)—OTP completed construction and testing of the Big Stone Plant AQCS in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. OTP's capitalized cost of the project, excluding allowance for funds used during construction, was approximately $200 million.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

REAGENT COSTS

OTP's systemwide costs for reagents are expected to increase to approximately $2.2 million annually through May 2021 when Hoot Lake Plant is expected to be retired. The Minnesota, North Dakota and South Dakota share of costs are approximately 50%, 40% and 10%, respectively. Reagent costs for the Big Stone Plant AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) were initially incurred in 2015 when projects went into service.

MINNESOTA

2016 General Rate Case—On February 16, 2016 OTP filed a request with the MPUC for an increase in revenue recoverable under general rates in Minnesota. In its filing, OTP requested an allowed rate of return on rate base of 8.07% and an allowed rate of return on equity of 10.4% based on an equity ratio of 52.5% of total capital. On April 14, 2016 the MPUC issued an order approving an interim rate increase of 9.56% to the base rate portion of customers' bills effective April 16, 2016, as modified and subject to refund. The request and interim rate information is detailed in the table below:

($ in thousands)	Annualized or Test Year	Actual Through December 31, 2016
Revenue Increase Requested	$ 19,296	
Increase Percentage Requested	9.80%	
Jurisdictional Rate Base	$ 483,000	
Interim Revenue Increase (subject to refund)	$ 16,816	$ 10,976

The major components of the requested rate increase are summarized below:

Revenue Requirement Deficiency Cost Factors *(in thousands)*	2016 Test Year Allocation
Increased Rate Base	$ 10,000
Increased Expenses	7,700
Other	1,596
Total Requested Revenue Increase	$ 19,296
Excluded from Interim Rates: Rate Base Effect of Prepaid Pension Asset	(2,480)
Approved Interim Revenue Increase (subject to refund)	$ 16,816

The deadline for submission of intervenor direct testimony was August 16, 2016. Direct testimony of the Minnesota Department of Commerce (MNDOC) included a recommendation for an 8.87% allowed rate of return on equity, and direct testimony of the Minnesota Office of the Attorney General (OAG) included a recommendation for a 6.96% allowed rate of return on equity. In response, in rebuttal testimony, OTP modified its request to provide for an allowed rate of return on equity of 10.05%. In rebuttal testimony, the MNDOC revised its recommendation to an 8.66% allowed rate of return on equity, and the Minnesota OAG revised its recommendation to a 7.14% allowed rate of return on equity. Hearings before the Administrative Law Judge (ALJ) occurred in October 2016. On January 5, 2017 the ALJ issued his report which included a recommendation for a 9.54% allowed rate of return on equity.

Based on OTP's modifications to its original request and other expected outcomes in the aforementioned rate case, OTP has recorded an estimated interim rate refund of $3.6 million as of December 31, 2016. Oral arguments before the MPUC are expected to occur in late February 2017. The MPUC is expected to make its final decision in March 2017 and issue its written order in spring 2017.

2010 General Rate Case—OTP's most recently completed general rate increase in Minnesota of approximately $5.0 million, or 1.6%, was granted by the MPUC in an order issued on April 25, 2011 and effective October 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%.

Minnesota Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the Minnesota Conservation Improvement Program (MNCIP) through the use of an annual recovery mechanism approved by the MPUC.

On September 26, 2014 the MPUC approved OTP's 2013 financial incentive request for $4.0 million, an updated surcharge rate to be effective October 1, 2014, as well as a change to the carrying charge to be equal to the short term cost of debt set in OTP's most recent general rate case.

OTP recognized a financial incentive for 2014 of $3.0 million due, in part, to the MPUC lowering the MNCIP financial incentive from approximately $0.09 per kwh saved for 2013-2015 to $0.07 per kwh saved for 2014-2016. Additionally, OTP saved approximately 2 million less kwhs in 2014 compared with 2013 under conservation improvement programs in Minnesota. On July 9, 2015 the MPUC granted approval of OTP's 2014 financial incentive of $3.0 million along with an updated surcharge with an effective date of October 1, 2015.

Based on results from the 2015 MNCIP program year, OTP recognized a financial incentive of $4.2 million. The 2015 MNCIP program resulted in an approximate 39% increase in energy savings compared to 2014 program results. On April 1, 2016 OTP requested approval for recovery of its 2015 MNCIP program costs not included in base rates, a $4.3 million financial incentive and an update to the MNCIP surcharge from the MPUC. On July 19, 2016 the MPUC issued an order approving OTP's request with an effective date of October 1, 2016.

Based on results from the 2016 MNCIP program year, OTP recognized a financial incentive of $5.1 million in 2016. The 2016 program resulted in an approximate 18% increase in energy savings compared to 2015 program results. OTP will request approval for recovery of its 2016 MNCIP program costs not included in base rates, a $5.1 million financial incentive and an update to the MNCIP surcharge from the MPUC by April 1, 2017.

On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model will provide utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate

of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule.

MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

OTP filed an annual update to its Minnesota TCR rider on February 7, 2013 to include three new projects as well as updated costs associated with existing projects. In a written order issued on March 10, 2014, the MPUC approved OTP's 2013 TCR rider update but found capitalized internal costs, costs in excess of CON estimates and a carrying charge ineligible for recovery through the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP is seeking recovery of the capitalized internal costs and costs in excess of CON estimates in its current general rate case filing in Minnesota. In response to the MPUC's approval of OTP's annual TCR update, OTP submitted a compliance filing in April 2014 reflecting the TCR rider revenue requirements changes relating to the MPUC's ruling and requesting no rate change be implemented at the time. The MPUC approved OTP's compliance filing on June 19, 2014. On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015. OTP filed an annual update to its Minnesota TCR rider on September 30, 2015 requesting revenue recovery of approximately $7.8 million. A supplemental filing to the update was made on December 21, 2015 to address an issue surrounding the proration of accumulated deferred income taxes and, in an unrelated adjustment, the TCR rider update revenue request was reduced to $7.2 million. On March 9, 2016 the MPUC issued an order approving OTP's annual update to its TCR rider, with an effective date of April 1, 2016.

OTP filed an update to its TCR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis, as recommended by the MNDOC. The proposed rate changes went into effect on September 1, 2016. The MPUC has granted extensions to the MNDOC to file initial comments in this docket until February 2, 2017.

In OTP's 2016 general rate case, the MNDOC has argued that the MPUC should require OTP to include in the TCR rider retail rate base 100% of OTP's investment in the Big Stone South—Brookings and Big Stone South—Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. OTP has opposed this treatment, arguing that the projects are appropriately assigned to the FERC jurisdiction, and the FERC's determination of the projects' revenue requirements should not be altered by forcing the revenues into the retail revenue requirement calculations. In the general rate case proceeding, the ALJ has recommended that the MPUC should affirm OTP's treatment. If the MPUC finds that the MNDOC's treatment should be followed, it would result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time.

Environmental Cost Recovery (ECR) Rider—On December 18, 2013 the MPUC granted approval of OTP's Minnesota ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS effective January 1, 2014. The ECR rider recoverable revenue requirements included a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's 2010 general rate case. The MPUC approved OTP's 2014 ECR rider annual update request on November 24, 2014 with an effective date of December 1, 2014. OTP filed its 2015 annual update on July 31, 2015, with a request to keep the 2014 annual update rate in place. On December 21, 2015 OTP filed a supplemental filing with updated financial information. The MPUC issued an order on March 9, 2016 approving OTP's request to leave the 2014 annual update rate in place. OTP filed an update to its Minnesota ECR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request, with an effective date of September 1, 2016. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis and has since granted extensions to the MNDOC to file initial comments in this docket until February 2, 2017. Reply comments were due from OTP on February 13, 2017.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs are included in OTP's 2016 general rate case in Minnesota and are being considered for recovery either through the FCA rider or general rates. These costs are currently being expensed as incurred.

NORTH DAKOTA

General Rates—OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment. The NDPSC approved OTP's 2013 annual update to its NDRRA on March 12, 2014 with an effective date of April 1, 2014, which resulted in a 13.5% reduction in the NDRRA rate. The NDPSC approved OTP's 2014 annual update to the NDRRA, including a change in rate design from an amount per kwh consumed to a percentage of a customer's bill, on March 25, 2015 with an effective date of April 1, 2015. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016. On February 25, 2016 OTP made a supplemental filing to address the impact of bonus depreciation for income taxes and related deferred tax

assets on the NDRRA, as well as an adjustment to the estimated amount of Federal Production Tax Credits used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflects a reduction in the return on equity (ROE) component of the rate from 10.75%, approved in OTP's most recent general rate case, to 10.50%. OTP submitted its 2016 annual update to the NDRRA rider rate on December 30, 2016, requesting a decrease to the NDRRA rate from 7.573% to 7.005%, with a requested implementation date of April 1, 2017.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case. The NDPSC approved OTP's 2014 annual update to its TCR rider rate on December 17, 2014 with an effective date of January 1, 2015. On August 31, 2015 OTP filed its 2015 annual update to its North Dakota TCR rider rate requesting recovery of approximately $10.2 million for 2016 compared with $8.5 million for 2015, including costs assessed by the MISO as well as new costs from the Southwest Power Pool (SPP) that OTP began incurring January 1, 2016. These new costs are associated with OTP's load connected to the transmission system of Central Power Electric Cooperative (CPEC). OTP's load became subject to SPP transmission-related charges when CPEC transmission assets were added to the SPP. The NDPSC approved OTP's 2015 annual update to its TCR rider rate on December 16, 2015, with an effective date of January 1, 2016. On September 1, 2016 OTP filed its annual update to the TCR rider requesting a revenue requirement of $5.7 million, which includes a reduction of $2.6 million for a projected over-collection for 2016. Primary drivers of the decrease from the 2015 updated rider rate include the impact of federal bonus depreciation and unresolved MISO ROE complaint proceedings. OTP filed a supplemental filing on September 14, 2016, requesting that the over-collection balance be spread over the next two years for purposes of reducing the volatility of the rates from year to year. The NDPSC approved the update on December 14, 2016. The new rates went into effect on January 1, 2017.

Environmental Cost Recovery Rider—On December 18, 2013 the NDPSC approved OTP's request for an ECR rider to recover OTP's North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS. The ECR provides for a current return on CWIP and a return on investment at the level approved in OTP's most recent general rate case. On March 31, 2014 OTP filed an annual update to its North Dakota ECR rider rate. The update included a request to increase the ECR rider rate from 4.319% of base rates to 7.531% of base rates. The NDPSC approved OTP's 2014 ECR rider annual update request on July 10, 2014 with an August 1, 2014 implementation date. On March 31, 2015 OTP filed its annual update to the ECR. This update included a request to increase the ECR rider rate from 7.531% to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015, along with the approval of recovery of OTP's North Dakota jurisdictional share of Hoot Lake Plant MATS project costs.

On March 31, 2016 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 9.193% to 7.904% of base rates, or a revenue requirement reduction from $12.2 million to $10.4 million, effective July 1, 2016. The rate reduction request was primarily due to the Company's 2015 bonus depreciation election for income taxes, which reduces revenue requirements. The filing was approved on June 22, 2016.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the NDPSC to revise its FCA rider in North Dakota to include recovery of new reagent and emission allowance costs. On February 25, 2015 the NDPSC approved recovery of these costs through modification of the ECR rider, instead of recovery through the FCA as OTP had proposed. The ECR rider reagent and emissions allowance charge became effective May 1, 2015.

SOUTH DAKOTA

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately $643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. The SDPUC approved OTP's 2013 annual update on February 18, 2014 with an effective date of March 1, 2014. The SDPUC approved OTP's 2014 annual update on February 13, 2015 with an effective date of March 1, 2015. OTP filed its 2015 annual update on October 30, 2015 with a proposed effective date of March 1, 2016. A supplemental filing was made on February 3, 2016 to true-up the filing to include the impact of bonus depreciation elected for 2015, the inclusion of a deferred tax asset relating to a net operating loss and the proration of accumulated deferred income taxes. This update included the recovery of new SPP transmission costs OTP began to incur on January 1, 2016. On February 12, 2016 the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2016. On November 1, 2016 OTP filed the annual update to the South Dakota TCR rider. OTP made a supplemental filing on January 20, 2017 to include updated costs through December 2016 as well as updated forecast information. The proposed effective date of the new rates is March 1, 2017.

Environmental Cost Recovery Rider—On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover OTP's South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects, with an effective date of December 1, 2014. On August 31, 2015 OTP filed its annual update to the South Dakota ECR requesting recovery of approximately $2.7 million in annual revenue. The SDPUC approved the request on October 15, 2015 with an effective date of November 1, 2015. On August 31, 2016 OTP filed its 2016 update to the ECR rider, requesting recovery of approximately $2.3 million in annual revenue. The SDPUC approved the request on October 26, 2016 with an effective date of November 1, 2016. The lower revenue requirement is a result of the implementation of federal bonus depreciation taken on the Big Stone Plant AQCS.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

REVENUES RECORDED UNDER RATE RIDERS

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the years ended December 31:

Rate Rider *(in thousands)*	2016	2015	2014
Minnesota			
Conservation Improvement Program Costs and Incentives *(1)*	**$ 12,920**	$ 10,724	$ 7,757
Environmental Cost Recovery	**12,443**	10,238	6,891
Transmission Cost Recovery	**5,795**	5,202	6,275
North Dakota			
Environmental Cost Recovery	**11,089**	9,502	5,872
Renewable Resource Adjustment	**7,800**	8,409	7,484
Transmission Cost Recovery	**7,694**	6,609	5,794
South Dakota			
Environmental Cost Recovery	**2,538**	1,967	234
Transmission Cost Recovery	**1,820**	1,290	1,207
Conservation Improvement Program Costs and Incentives	**468**	583	435

(1) Includes MNCIP costs recovered in base rates.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935, as amended. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing.

Effective January 1, 2012 the FERC authorized OTP to recover 100% of prudently incurred CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVPs in MISO's 2011 Transmission Expansion Plan: the Big Stone South–Brookings MVP and the Big Stone South–Ellendale MVP.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. On October 16, 2014 the FERC issued an order finding that the current MISO ROE may be unjust and unreasonable and setting the issue for hearing. Parties, including OTP, sought rehearing of the FERC's decision to set the November 12, 2013 complaint for hearing. This rehearing was denied on July 21, 2016. On September 19, 2016 the MISO transmission owners sought appeal to the United States Court of Appeals for the District of Columbia (D.C. Circuit). A non-binding decision by the presiding ALJ was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, which were held the week of February 16, 2016. Parties, including OTP, sought rehearing of the FERC's decision to set the November 12, 2013 complaint for hearing. This rehearing was denied on July 21, 2016. On September 19, 2016 the MISO transmission owners sought appeal to the D.C. Circuit. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. The FERC is expected to issue its order not earlier than spring 2017.

Based on a potential reduction by the FERC in the ROE component of the MISO Tariff, OTP recorded reductions in revenue of $1.6 million in 2016 and $1.1 million in 2015 and has a $2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives.

The following tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

	December 31, 2016			Remaining Recovery
(in thousands)	Current	Long-Term	Total	/Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits *(1)*	$ 6,443	$ 108,267	$ 114,710	see below
Deferred Marked-to-Market Losses *(1)*	4,063	6,467	10,530	48 months
Conservation Improvement Program Costs and Incentives *(2)*	4,836	5,158	9,994	21 months
Accumulated ARO Accretion/Depreciation Adjustment *(1)*	—	6,153	6,153	asset lives
Big Stone II Unrecovered Project Costs—Minnesota *(1)*	778	2,087	2,865	52 months
North Dakota Renewable Resource Rider Accrued Revenues *(2)*	1,319	482	1,801	15 months
Recoverable Fuel and Purchased Power Costs *(1)*	1,798	—	1,798	12 months
Debt Reacquisition Premiums *(1)*	325	1,214	1,539	189 months
Minnesota Deferred Rate Case Expenses Subject to Recovery *(1)*	1,082	—	1,082	12 months
Deferred Income Taxes *(1)*	—	1,014	1,014	asset lives
Big Stone II Unrecovered Project Costs—South Dakota *(2)*	100	543	643	77 months
North Dakota Transmission Cost Recovery Rider Accrued Revenues *(2)*	—	568	568	24 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up *(2)*	333	—	333	12 months
South Dakota Transmission Cost Recovery Rider Accrued Revenues *(2)*	73	141	214	14 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues *(2)*	113	—	113	12 months
Minnesota Renewable Resource Rider Accrued Revenues *(2)*	34	—	34	9 months
Total Regulatory Assets	$ 21,297	$ 132,094	$ 153,391	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs—Net of Salvage	$ —	$ 80,404	$ 80,404	asset lives
North Dakota Transmission Cost Recovery Rider Accrued Refund	1,381	782	2,163	24 months
Revenue for Rate Case Expenses Subject to Refund—Minnesota	711	208	919	16 months
Deferred Income Taxes	—	818	818	asset lives
Minnesota Transmission Cost Recovery Rider Accrued Refund	757	—	757	12 months
South Dakota Environmental Cost Recovery Rider Accrued Refund	285	—	285	12 months
Minnesota Environmental Cost Recovery Rider Accrued Refund	139	—	139	12 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	—	132	132	24 months
Other	21	89	110	204 months
Total Regulatory Liabilities	$ 3,294	$ 82,433	$ 85,727	
Net Regulatory Asset Position	$ 18,003	$ 49,661	$ 67,664	

(1) Costs subject to recovery without a rate of return.
(2) Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

	December 31, 2015			Remaining Recovery
(in thousands)	Current	Long-Term	Total	/Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits *(1)*	$ 7,439	$ 99,293	$ 106,732	see below
Deferred Marked-to-Market Losses *(1)*	4,063	10,530	14,593	60 months
Conservation Improvement Program Costs and Incentives *(2)*	4,411	4,266	8,677	18 months
Accumulated ARO Accretion/Depreciation Adjustment *(1)*	—	5,672	5,672	asset lives
Big Stone II Unrecovered Project Costs—Minnesota *(1)*	942	2,620	3,562	84 months
North Dakota Renewable Resource Rider Accrued Revenues *(2)*	—	1,266	1,266	15 months
Debt Reacquisition Premiums *(1)*	351	1,539	1,890	201 months
Minnesota Deferred Rate Case Expenses Subject to Recovery *(1)*	291	—	291	12 months
Deferred Income Taxes *(1)*	—	1,455	1,455	asset lives
Big Stone II Unrecovered Project Costs—South Dakota *(2)*	100	643	743	89 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up *(2)*	698	355	1,053	24 months
Minnesota Transmission Cost Recovery Rider Accrued Revenues *(2)*	576	—	576	12 months
South Dakota Transmission Cost Recovery Rider Accrued Revenues *(2)*	33	—	33	12 months
Minnesota Renewable Resource Rider Accrued Revenues *(2)*	—	68	68	see below
Total Regulatory Assets	$ 18,904	$ 127,707	$ 146,611	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs—Net of Salvage	$ —	$ 74,948	$ 74,948	asset lives
Refundable Fuel Clause Adjustment Revenues	1,834	—	1,834	12 months
North Dakota Transmission Cost Recovery Rider Accrued Refund	132	—	132	12 months
Revenue for Rate Case Expenses Subject to Refund—Minnesota	—	1,279	1,279	see below
Deferred Income Taxes	—	1,110	1,110	asset lives
South Dakota Environmental Cost Recovery Rider Accrued Refund	185	—	185	12 months
Minnesota Environmental Cost Recovery Rider Accrued Refund	777	—	777	12 months
Deferred Gain on Sale of Utility Property—Minnesota Portion	5	95	100	216 months
North Dakota Environmental Cost Recovery Rider Accrued Refund	321	—	321	12 months
North Dakota Renewable Resource Rider Accrued Refund	68	—	68	12 months
Total Regulatory Liabilities	$ 3,322	$ 77,432	$ 80,754	
Net Regulatory Asset Position	$ 15,582	$ 50,275	$ 65,857	

(1) Costs subject to recovery without a rate of return.
(2) Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC Topic 715, *Compensation—Retirement Benefits*, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Losses recorded as of December 31, 2016 relate to forward purchases of energy scheduled for delivery through December 2020.

Conservation Improvement Program Costs and Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates.

The Accumulated Asset Retirement Obligation (ARO) Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

Big Stone II Unrecovered Project Costs—Minnesota are the Minnesota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2016.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 189 months.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota currently being recovered over a 24-month period beginning with the establishment of interim rates in April 2016.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes*.

Big Stone II Unrecovered Project Costs—South Dakota are the South Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

The North Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to North Dakota customers as of December 31, 2016.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-ups relate to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-ups also include the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

The South Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to South Dakota customers as of December 31, 2016.

The North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that have not been billed to North Dakota customers as of December 31, 2016.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers. On April 4, 2013 the MPUC approved OTP's request to set the rider rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered over an 18-month period beginning with the establishment of interim rates in April 2016.

The Accumulated Reserve for Estimated Removal Costs—Net of Salvage is reduced as actual removal costs, net of salvage revenues, are incurred.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2016.

Revenue for Rate Case Expenses Subject to Refund—Minnesota relates to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund over a 24-month period beginning with the establishment of interim rates in April 2016.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2016.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of December 31, 2016.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of December 31, 2016.

If for any reason OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Open Contract Positions Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases and carried at historical cost in the accompanying balance sheet. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. The following table shows the current fair value of these forward contract positions subject to legally enforceable netting arrangements as of December 31:

(in thousands)	2016	2015
Derivatives in Gain Positions Subject to Legally Enforceable Netting Arrangements	**$ —**	$ —
Open Contract Loss Positions Subject to Legally Enforceable Netting Arrangements	**(17,382)**	(16,070)
Net Balance Subject to Legally Enforceable Netting Arrangements	**$ (17,382)**	$ (16,070)

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of December 31:

(in thousands)	2016	2015
Loss Contracts Covered by Deposited Funds or Letters of Credit	$ —	$ 199
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade *(1)*	**17,382**	15,871
Total Loss Contracts based on Current Market Values	**$ 17,382**	$ 16,070
(1) Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions.		
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	*$ 17,382*	*$ 15,871*
Offsetting Gains with Counterparties under Master Netting Agreements	*—*	*—*
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	*$ 17,382*	*$ 15,871*

6. Common Shares and Earnings per Share

Shelf Registration

The Company's shelf registration statement filed with the Securities and Exchange Commission on May 11, 2015, under which the Company 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, including common shares of the Company, expires on May 11, 2018.

Common Share Distribution Agreement

On May 11, 2015, the Company entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which it may offer and sell its common shares from time to time in an At-the-Market offering program through JPMS, as its distribution agent, up to an aggregate sales price of $75 million.

Under the Distribution Agreement, the Company will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. Sales of the shares, if any, will be made by means of ordinary brokers' transactions on the NASDAQ Global Select Market at market prices or as otherwise agreed with JPMS. The Company may also agree to sell shares to JPMS, as principal for its own account, on terms agreed by the Company and JPMS in a separate agreement at the time of sale. The Company is not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Distribution Agreement. The shares, if issued, will be issued pursuant to the Company's existing shelf registration statement.

2016 Common Stock Activity

Following is a reconciliation of the Company's common shares outstanding from December 31, 2015 through December 31, 2016:

Common Shares Outstanding, December 31, 2015	37,857,186
Issuances:	
At-the-Market Offering	1,014,115
Automatic Dividend Reinvestment and Share Purchase Plan:	
Dividends Reinvested	163,010
Cash Invested	115,801
Vesting of Executive Stock Performance Awards	54,700
Employee Stock Purchase Plan:	
Cash Invested	53,875
Dividends Reinvested	23,713
Employee Stock Ownership Plan	23,837
Restricted Stock Issued to Directors	23,200
Vesting of Restricted Stock Units	21,825
Directors Deferred Compensation	542
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(3,668)
Common Shares Outstanding, December 31, 2016	39,348,136

2014 Stock Incentive Plan

The 2014 Stock Incentive Plan (2014 Incentive Plan), which was approved by the Company's shareholders in April 2014, provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 1,900,000 common shares were authorized for granting stock awards under the 2014 Incentive Plan, of which 1,356,811 were available for issuance as of December 31, 2016. The 2014 Incentive Plan terminates on December 13, 2023.

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. For purchase periods beginning after January 1, 2017, the purchase price will be 100% of the market price at the end of each six-month purchase period. On April 16, 2012, the Company's shareholders approved an amendment to the Purchase Plan, increasing the number of shares available under the Purchase Plan from 900,000 common shares to 1,400,000 common shares and making certain other changes to the terms of the Purchase Plan. Of the 1,400,000 common shares authorized to be issued under the Purchase Plan, 384,159 were available for purchase as of December 31, 2016. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for purchases for the Purchase Plan, 53,875 common shares were issued in 2016, 42,253 common shares were issued in 2015 and 39,222 common shares were issued in 2014. The shares to be purchased by employees participating in the Purchase Plan were not material to the calculation of diluted earnings per share during the investment period.

Dividend Reinvestment and Share Purchase Plan

The Company's shelf registration statement filed with the SEC on May 11, 2015, as amended on October 13, 2015, provides for the issuance of up to 1,500,000 common shares under the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by participants in the Plan to be either new issue common shares or common shares purchased in the open market. New common shares issued under the Plan totaled 278,811 in 2016 and 302,519 in 2015, leaving 918,670 common shares available for issuance under the Plan as of December 31, 2016.

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income with no adjustments in 2016, 2015 and 2014. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company's directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting basic shares outstanding for the items listed in the following reconciliation:

	2016	2015	2014
Weighted Average Common Shares Outstanding—Basic	**38,546,459**	37,494,986	36,514,397
Plus Outstanding Share Awards net of Share Reductions for Unrecognized Stock-Based Compensation Expense and Excess Tax Benefits:			
Shares Expected to be Awarded for Stock Performance Awards Granted to Executive Officers based on Measurement Period-to-Date Performance	**118,644**	100,194	135,480
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	**45,712**	36,180	27,540
Nonvested Restricted Shares	**16,778**	22,848	49,998
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	**3,417**	13,488	24,048
Potentially Dilutive Stock Options	**—**	330	1,096
Total Dilutive Shares	**184,551**	173,040	238,162
Weighted Average Common Shares Outstanding—Diluted	**38,731,010**	37,668,026	36,752,559

The effect of dilutive shares on earnings per share for the years ended December 31, 2016, 2015 and 2014, resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in any period.

7. Share-Based Payments

Purchase Plan

Through December 31, 2016, the Purchase Plan allowed employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under ASC Topic 718, *Compensation—Stock Compensation* (ASC 718), the Company is required to record compensation expense related to the 15% discount. The 15% discount resulted in compensation expense of $173,000 in 2016, $184,000 in 2015 and $175,000 in 2014. For purchase periods beginning after January 1, 2017, the purchase price will be 100% of the market price at the end of each six-month purchase period.

Stock Options Granted Under the 1999 Incentive Plan

The Company granted 2,041,500 options for the purchase of the Company's common stock under the 1999 Stock Incentive Plan (1999 Incentive Plan). The exercise price of the options granted was the average market price of the Company's common stock on the grant date. Under ASC 718 accounting requirements, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under ASC 718 accounting requirements, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the 1999 Incentive Plan was based on the Black-Scholes option pricing model. There were no options outstanding as of December 31, 2016 or December 31, 2015.

Presented below is a summary of the stock options activity:

Stock Option Activity	2016		2015		2014	
	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	—		12,750	$ 24.93	34,700	$ 25.69
Exercised	—		10,250	24.93	20,800	26.11
Forfeited or Expired	—		2,500	24.93	1,150	26.495
Outstanding, End of Year	—		—		12,750	24.93
Exercisable, End of Year	—		—		12,750	24.93
Cash Received for Options Exercised				$ 256,000		$ 543,000
Intrinsic Value of Options Exercised				$ 75,000		$ 89,000

Restricted Stock Granted to Directors

Under the 1999 Incentive Plan and the 2014 Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's board of directors as a form of compensation. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 11, 2016, 23,200 shares of restricted stock were granted to the Company's nonemployee directors. The grant-date fair value of each share of restricted stock granted on April 11, 2016 was $28.66 per share, the average of the high and low market price on the date of grant. The restricted shares granted in 2016 vest 25% per year on April 8 of each year in the period 2017 through 2020 and are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreement.

Presented below is a summary of the status of directors' restricted stock awards for the years ended December 31:

Directors' Restricted Stock Awards	2016		2015		2014	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	**38,217**	**$ 29.78**	38,050	$ 27.47	42,483	$ 25.03
Granted	**23,200**	**28.66**	15,200	31.775	16,800	29.41
Vested	**15,083**	**28.28**	15,033	25.96	21,233	24.11
Forfeited	**—**		—		—	
Nonvested, End of Year	**46,334**	**29.71**	38,217	29.78	38,050	27.47
Compensation Expense Recognized		**$ 491,000**		$ 417,000		$ 416,000
Fair Value of Shares Vested in Year		**$ 427,000**		$ 390,000		$ 512,000

Restricted Stock Granted to Employees

Under the 1999 Incentive Plan and 2014 Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. No shares of restricted stock were granted to employees in 2016 or 2015.

Presented below is a summary of the status of employees' restricted stock awards for the years ended December 31:

Employees' Restricted Stock Awards	2016		2015		2014	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	**13,581**	**$ 28.56**	45,280	$ 27.46	48,315	$ 25.04
Granted	**—**		—		26,700	29.41
Vested	**6,401**	**27.25**	31,699	27.09	25,360	24.80
Forfeited	**—**		—		4,375	28.03
Nonvested, End of Year	**7,180**	**29.72**	13,581	28.56	45,280	27.46
Compensation Expense Recognized		**$ 96,000**		$ 359,000		$ 998,000
Fair Value of Awards Vested		**$ 174,000**		$ 859,000		$ 629,000

Restricted Stock Units Granted to Executive Officers

On February 4, 2016, 22,000 restricted stock units under the 2014 Incentive Plan were granted to the Company's executive officers. The grant-date fair value of each restricted stock unit was $28.915 per share, the average of the high and low market price on the date of grant. The restricted stock units granted to executive officers in 2016 vest 25% per year on February 6 of each year in the period 2017 through 2020 and are eligible to receive dividend equivalent payments on all unvested awards over the awards' respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration on retirement in certain cases.

Presented below is a summary of the status of restricted stock unit awards granted to executive officers for the years ended December 31:

Executives' Restricted Stock Unit Awards	2016		2015	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	**24,300**	**$ 31.682**	—	
Granted	**22,000**	**28.915**	29,100	$ 31.681
Vested	**4,475**	**31.69**	4,800	31.675
Forfeited	**—**		—	
Nonvested, End of Year	**41,825**	**30.23**	24,300	31.682
Compensation Expense Recognized		**$ 446,000**		$ 452,000
Fair Value of Awards Vested		**$ 142,000**		$ 152,000

Restricted Stock Units Granted to Employees

In 2016 the following restricted stock unit awards under the 2014 Incentive Plan were granted to key employees of the Company who are not executive officers:

	Grant Date	Units Granted	Grant-Date Fair Value per Award
Restricted Stock Units Vesting 100% on April 8, 2020	April 11, 2016	15,800	$24.00
Restricted Stock Units Vesting 100% on April 8, 2020	September 21, 2016	1,420	$30.59

The grant-date fair value of each restricted stock unit was based on the average of the high and low market price of the Company's common stock on the date of grant, discounted for the value of the dividend exclusion over the four-year vesting period. Under the terms of the restricted stock unit award agreements, all outstanding (unvested) restricted stock units held by a retiring grantee vest immediately on normal retirement.

Presented below is a summary of the status of employees' restricted stock unit awards for the years ended December 31:

Employees' Restricted Stock Unit Awards	2016		2015		2014	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	**46,600**	**$ 23.75**	45,900	$ 21.82	56,180	$ 19.79
Granted	**17,220**	**24.54**	15,650	25.89	11,800	24.95
Reinstated	**—**		—		75	30.81
Vested	**12,250**	**19.03**	12,250	19.46	14,305	18.05
Forfeited	**4,200**	**24.51**	2,700	22.84	7,850	18.90
Nonvested, End of Year	**47,370**	**25.19**	46,600	23.75	45,900	21.82
Compensation Expense Recognized		**$ 307,000**		$ 304,000		$ 194,000
Fair Value of Awards Vested		**$ 233,000**		$ 238,000		$ 258,000

Stock Performance Awards granted to Executive Officers

Stock performance award agreements have been granted under the 1999 Incentive Plan and the 2014 Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. Awards granted in 2016 and 2015 also included a performance incentive based on the Company's average 3-year adjusted return on equity relative to a targeted average 3-year adjusted return on equity. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period.

On February 4, 2016 performance share awards were granted to the Company's executive officers under the 2014 Incentive Plan for the 2016-2018 performance measurement period. Under the 2016 performance share award agreements the aggregate award for performance at target is 81,500 shares. For target performance the Company's executive officers would earn an aggregate of 54,333 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance measurement period of January 1, 2016 through December 31, 2018. The Company's executive officers would also earn an aggregate of 27,167 common shares for achieving the target set for the Company's 3-year average adjusted return on equity. Actual payment may range from zero to 150% of the target amount, or up to 122,250 common shares.

Under the 2016 performance award agreements, payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to certain officers who are parties to executive employment agreements with the Company is to be made at the target amount at the date of any such event. The vesting of these performance award agreements is accelerated and paid at target in the event of a change in control, disability or death (and upon retirement at or after age 62 for certain officers who are parties to executive employment agreements with the Company).

Through December 31, 2015, the income tax withholding terms applicable to outstanding performance awards dictated that the awards be classified and accounted for as liability awards, in accordance with the requirements of ASC 718, with compensation measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date. In the fourth quarter of 2016, the Company elected to early adopt the updates in ASU 2016-09, resulting in the outstanding 2015 and 2016 performance awards being now classified as equity awards. See note 1 for additional information on the impact of the adoption of ASU 2016-09.

The table below provides a summary of stock performance awards granted and amounts expensed related to the stock performance awards:

Performance Period	Maximum Shares Subject To Award	Target Shares	Expense Recognized in the Year Ended December 31, *(1)*			Earned Shares
			2016	2015	2014	
2016-2018	122,250	81,500	**$ 798,000**			
2015-2017	126,450	84,300	**535,000**	$ 943,000		
2014-2016	159,450	106,300	**332,000**	(64,000)	$ 1,422,000	121,491
2013-2015	90,600	45,300	**—**	(445,000)	458,000	22,500
2012-2014	148,400	74,200	**—**	—	142,000	89,991
Total			**$ 1,665,000**	$ 434,000	$ 2,022,000	233,982

(1) Expenses prior to 2016 are not restated to reflect what would have been expensed had the performance-to-date value of the outstanding awards been based on the grant-date fair value of the awards rather than the reporting-date fair value of the awards.

Stock-based payment expense recognized in 2016 and 2015 for the 2016-2018 and 2015-2017 performance awards reflects the accelerated recognition of expense for outstanding and unvested awards of executives who are eligible for retirement and whose awards vest on normal retirement, as defined in the performance award agreements, prior to the vesting dates of the awards.

The earned shares shown in the table above for the 2014-2016 performance period include shares received in 2017 by participants in the plan, based on the Company achieving a total shareholder return ranking of 19 out of 43 companies in the EEI Index and a resulting payout at 114.29% of target. The earned shares also include shares for a portion of the award that vested on normal retirement of the Company's former CEO on July 1, 2015 that were issued in 2016 following the 180 day deferral period required under the Internal Revenue Code at a value of $26.35 per share or $848,000.

The earned shares shown in the table above for the 2013-2015 performance period reflect shares that vested on normal retirement of the Company's former CEO on July 1, 2015 that were issued in 2016 following the 180 day deferral period required under the Internal Revenue Code at a value of $26.35 per share or $593,000.

The earned shares shown in the table above for the 2012-2014 performance period reflect shares received in 2015 by active participants in the plan on December 31, 2014, based on the Company achieving a total shareholder return ranking of 21 out of 48 companies in the EEI Index and a resulting payout at 121.28% of target.

In connection with the resignation of executive officers in May 2014 and March 2012, the following unvested stock performance awards were forfeited: 8,900 granted in 2014, 4,900 granted in 2013, and 6,600 granted in 2012.

As of December 31, 2016 the total remaining unrecognized amount of compensation expense related to stock-based compensation for all of the Company's stock-based payment programs was approximately $4.0 million (before income taxes), which will be amortized over a weighted average period of 2.2 years.

8. Retained Earnings and Dividend Restriction

The Company is a holding company with no significant operations of its own. The primary source of funds for payments of dividends to the Company's shareholders is from dividends paid or distributions made by the Company's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by the Company's subsidiaries.

Both the Company and OTP credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of December 31, 2016 the Company was in compliance with these financial covenants. See note 10 to consolidated financial statements for further information on the 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 or the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between 47.5% and 58.1% based on OTP's 2016 capital structure petition approved by order of the MPUC on August 2, 2016. As of December 31, 2016 OTP's equity-to-total-capitalization ratio including short-term debt was 52.9% and its net assets restricted from distribution totaled approximately $440,000,000. Total capitalization for OTP cannot currently exceed $1,123,168,000.

9. Commitments and Contingencies of Continuing Operations

Construction and Other Purchase Commitments

At December 31, 2016 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately $84.8 million.

Electric Utility Capacity and Energy Requirements and Coal Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2040. OTP has commitments under contracts providing for the purchase of a significant portion of its current coal requirements. Current coal purchase agreements for Big Stone Plant and Coyote Station expire in 2017 and 2040, respectively. In January 2016, OTP entered into an agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant for the period of January 1, 2016 through December 31, 2023. OTP has no fixed minimum purchase requirements under the agreement but all of Hoot Lake Plant's coal requirements for the period covered must be purchased under this agreement. The dollar amounts of OTP's estimated purchase requirements under this agreement are excluded from the table below because OTP has not committed to any minimum level of purchases under the agreement. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they provide for recovery of most fuel costs. See table below for schedule of commitments.

Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment. Rent expense from continuing operations was $7,565,000, $6,447,000 and $10,165,000 for 2016, 2015 and 2014, respectively.

The amounts of the Company's construction program and other commitments and commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases for continuing operations as of December 31, 2016, are as follows:

(in thousands)	Construction Program and Other Commitments	Capacity and Energy Requirements	Coal Purchase Commitments	Operating Leases		
				OTP	Nonelectric	Total
2017	$ 74,328	$ 23,711	$ 30,699	$ 2,374	$ 4,760	$ 7,134
2018	7,139	24,356	21,563	1,513	4,129	5,642
2019	3,331	24,925	22,102	1,237	2,598	3,835
2020	—	24,844	22,331	1,251	2,259	3,510
2021	—	12,988	22,840	1,103	1,996	3,099
Beyond 2021	—	166,137	550,719	9,396	7,320	16,716
Total	$ 84,798	$ 276,961	$ 670,254	$ 16,874	$ 23,062	$ 39,936

Contingencies

Based on the reduction by the FERC in the ROE component of the MISO Tariff, OTP has a $2.7 million liability on its balance sheet as of December 31, 2016 representing OTP's best estimate of its current refund obligation related to amounts collected under the MISO Tariff, net of amounts that would be subject to recovery under state jurisdictional TCR riders.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders and the FERC's decision to resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. These consolidated cases are currently held in abeyance while the parties engage in mediation before the D.C. Circuit. OTP is an intervenor in these cases and a participant in mediation. The scope of the issues that will be subject to appeal at the D.C. Circuit have not yet been finalized. In addition, MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, the Company cannot estimate OTP's exposure at this time from a final order reversing the relevant FERC orders. Although the Company cannot estimate OTP's exposure at this time, a final order reversing the relevant FERC orders could have a material adverse effect on the Company's results of operations.

Contingencies, by their nature, relate to uncertainties that require the Company's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies impacting the Company's consolidated financial statements are those related to environmental remediation, risks associated with indemnification obligations under divestitures of discontinued operations and litigation matters. Should all of these known items result in liabilities being incurred, the loss could be as high as $1.0 million, excluding any liability for RSG charges for which an estimate cannot be made at this time.

In 2014 the Environmental Protection Agency (EPA) published proposed standards of performance for carbon dioxide (CO_2) emissions from new fossil fuel-fired power plants, proposed CO_2 emission guidelines for existing fossil fuel-fired power plants and proposed CO_2 standards of performance for CO_2 emissions from reconstructed and modified fossil fuel-fired power plants under section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. All of these rules have been challenged on legal grounds and are currently pending before the D.C. Circuit. On February 9, 2016 the U.S. Supreme Court granted a stay of the CO_2 emission guidelines for existing fossil fuel-fired power plants, pending disposition of petitions for review in the D.C. Circuit and, if a petition for a writ of certiorari seeking review by the U.S. Supreme Court were granted, any final Supreme Court determination. The D.C. Circuit heard oral argument on challenges to the CO_2 emission guidelines on September 27, 2016 before the full court, and a decision will likely be rendered in the first half of 2017. In addition, members of Congress and the new administration have been very critical of the Clean Power Plan (CPP) and may take actions that could impact the rule or the litigation. Therefore, while the CPP remains stayed, there is uncertainty regarding the future of the rule. The final outcome of this rulemaking process could have an adverse impact on the Company's business and results of operations.

Other

The Company is a party to litigation and regulatory enforcement matters arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2016 will not be material.

10. Short-Term and Long-Term Borrowings

SHORT-TERM DEBT

The following table presents the status of the Company's lines of credit as of December 31, 2016 and December 31, 2015:

(in thousands)	Line Limit	In Use on December 31, 2016	Restricted due to Outstanding Letters of Credit	Available on December 31, 2016	Available on December 31, 2015
Otter Tail Corporation Credit Agreement	$ 130,000	$ —	$ —	$ 130,000	$ 90,334
OTP Credit Agreement	170,000	42,883	50	127,067	148,694
Total	$ 300,000	$ 42,883	$ 50	$ 257,067	$ 239,028

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2016 was $63,757,000 on January 4, 2016 and the average daily balance of debt outstanding during 2016 was $16,200,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2016 was 2.3% compared with 2.0% in 2015. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2016 was $51,885,000 on December 16, 2016 and the average daily balance of debt outstanding during 2016 was $32,576,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2016 was 1.8% compared with 1.5% in 2015. The maximum amount of consolidated short-term debt outstanding in 2016 was $87,211,000 on January 25, 2016 and the average daily balance of consolidated short-term debt outstanding during 2016 was $48,776,000. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2016 was 1.9%.

On October 29, 2012 the Company entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $130 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 31, 2016 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2020 to October 29, 2021 and the unsecured revolving credit facility was reduced from $150 million to $130 million. The Company can draw on this credit facility to refinance certain indebtedness and support its operations and the operations of its subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on the Company's senior unsecured credit ratings. The Company is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on the Company and the businesses of its wholly owned subsidiary, Varistar Corporation (Varistar) and its subsidiaries, including restrictions on the Company's and Varistar's ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. The Company's obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of the Company's subsidiaries. Outstanding letters of credit issued by the Company under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2016 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2020 to October 29, 2021. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its 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 OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

LONG-TERM DEBT ISSUANCES AND RETIREMENTS

2016 Note Purchase Agreement

On September 23, 2016 the Company entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which the Company agreed to issue to the purchasers, in a private placement transaction, $80 million aggregate principal amount of our 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The 2026 Notes were issued on December 13, 2016. The Company's obligations under the 2016 Note Purchase Agreement and the 2026 Notes are guaranteed by its Material Subsidiaries (as defined in the 2016 Note Purchase Agreement, but specifically excluding OTP). The proceeds from the issuance of the 2026 Notes were used to repay the remaining $52,330,000 of our 9.000% Senior Notes due December 15, 2016, and to pay down a portion of the $50 million in funds borrowed in February 2016 under the Company's term loan agreement.

The Company may prepay all or any part of the 2026 Notes (in an amount not less than 10% of the aggregate principal amount of the 2026 Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2016 Note Purchase Agreement, any optional prepayment made by the Company of all of the 2026 Notes on or after September 15, 2026 will be made without any make-whole amount. The Company is required to offer to prepay all of the outstanding 2026 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2016 Note Purchase Agreement) of the Company. In addition, if the Company and its Material Subsidiaries sell a "substantial part" of its or their assets and use the proceeds to prepay or retire senior Interest-bearing Debt (as defined in the 2016 Note Purchase Agreement) of the Company and/or a Material Subsidiary in accordance with the terms of the 2016 Note Purchase Agreement, we are required to offer to prepay a Ratable Portion (as defined in the 2016 Note Purchase Agreement) of the 2026 Notes held by each holder of the 2026 Notes.

The 2016 Note Purchase Agreement contains a number of restrictions on the business of the Company and the Material Subsidiaries that became effective on execution of the 2016 Note Purchase Agreement. These include restrictions on the Company's and the Material Subsidiaries' abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, engage in transactions with related parties, redeem or pay dividends on the Company's and the Material Subsidiaries' shares of capital stock, and make investments. The 2016 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2016 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's or the Material Subsidiaries' credit ratings.

Term Loan Agreement

On February 5, 2016 the Company entered into a Term Loan Agreement (the Term Loan Agreement) with the Banks named therein, JPMorgan Chase Bank, N.A., as administrative agent, and JPMS, as Lead Arranger and Book Runner. The Term Loan Agreement provides for an unsecured term loan with an aggregate commitment of $50 million that the Company may use for purposes of funding working capital, capital expenditures and other corporate purposes of the Company and certain of our subsidiaries. Under the Term Loan Agreement, the Company may, on up to two occasions, enter into additional tranches of term loans in minimum

increments of $10 million, subject to the consent of the lenders and so long as the aggregate amount of outstanding term loans does not exceed $100 million at any time. Borrowings under the Term Loan Agreement will bear interest at either (1) LIBOR plus 0.90% or (2) the greater of (a) the Prime Rate, (b) the Federal Reserve Bank of New York Rate plus 0.50% and (c) LIBOR multiplied by the Statutory Reserve Rate plus 1%. The applicable interest rate will depend on the Company's election of whether to make the advance a LIBOR advance. The Term Loan Agreement terminates on February 5, 2018.

On February 5, 2016 the Company borrowed $50 million under the Term Loan Agreement at an interest rate based on the 30 day LIBOR plus 90 basis points and used the proceeds to pay down borrowings under the Otter Tail Corporation Credit Agreement that were used to fund the expansion of BTD's Minnesota facilities in 2015 and to fund the September 1, 2015 acquisition of BTD-Georgia.

The Term Loan Agreement contains a number of restrictions on the Company, Varistar and certain subsidiaries of Varistar, including restrictions on its and their 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 Term Loan Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The Term Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. The Company's obligations under the Term Loan Agreement are guaranteed by Varistar and certain of its subsidiaries.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) pursuant to which OTP has agreed to issue to the purchasers named therein, in a private placement transaction, $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The Notes were issued on February 27, 2014. OTP used a portion of the proceeds of the Notes to retire early a $40.9 million term loan then outstanding and to repay OTP's short-term debt outstanding on February 27, 2014. The remaining proceeds of the Notes were used to pay fees and expenses related to the issuance of the Notes and for other general purposes, including construction program expenditures.

The 2013 Note Purchase Agreement states that 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 prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's 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 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement).

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (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 prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's 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 note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Shelf Registration

On May 11, 2015 the Company filed a shelf registration statement with the SEC under which the Company 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, which expires on May 11, 2018.

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of December 31, 2016 and December 31, 2015:

December 31, 2016 *(in thousands)*	**OTP**	**Otter Tail Corporation**	**Otter Tail Corporation Consolidated**
Short-Term Debt	**$ 42,883**	**$ —**	**$ 42,883**
Long-Term Debt:			
Term Loan, LIBOR plus 0.90%, due February 5, 2018		**$ 15,000**	**$ 15,000**
3.55% Guaranteed Senior Notes, due December 15, 2026		**80,000**	**80,000**
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	**$ 33,000**		**33,000**
Senior Unsecured Notes 4.63%, due December 1, 2021	**140,000**		**140,000**
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	**30,000**		**30,000**
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	**42,000**		**42,000**
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	**60,000**		**60,000**
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	**50,000**		**50,000**
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	**90,000**		**90,000**
North Dakota Development Note, 3.95%, due April 1, 2018		**106**	**106**
PACE Note, 2.54%, due March 18, 2021		**836**	**836**
Total	**$ 445,000**	**$ 95,942**	**$ 540,942**
Less: Current Maturities net of Unamortized Debt Issuance Costs	**32,970**	**231**	**33,201**
Unamortized Long-Term Debt Issuance Costs	**1,861**	**539**	**2,400**
Total Long-Term Debt net of Unamortized Debt Issuance Costs	**$ 410,169**	**$ 95,172**	**$ 505,341**
Total Short-Term and Long-Term Debt (with current maturities)	**$ 486,022**	**$ 95,403**	**$ 581,425**

December 31, 2015 *(in thousands)*	**OTP**	**Otter Tail Corporation**	**Otter Tail Corporation Consolidated**
Short-Term Debt	$ 21,006	$ 59,666	$ 80,672
Long-Term Debt:			
9.000% Notes, due December 15, 2016		$ 52,330	$ 52,330
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	$ 33,000		33,000
Senior Unsecured Notes 4.63%, due December 1, 2021	140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
North Dakota Development Note, 3.95%, due April 1, 2018		182	182
PACE Note, 2.54%, due March 18, 2021		977	977
Total	$ 445,000	$ 53,489	$ 498,489
Less: Current Maturities net of Unamortized Debt Issuance Costs		52,422	52,422
Unamortized Long-Term Debt Issuance Costs	2,099	122	2,221
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$ 442,901	$ 945	$ 443,846
Total Short-Term and Long-Term Debt (with current maturities)	$ 463,907	$ 113,033	$ 576,940

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2016 for each of the next five years are:

(in thousands)	2017	2018	2019	2020	2021
Aggregate Amounts of Debt Maturities	$ 33,231	$ 15,187	$ 172	$ 185	$ 140,171

FINANCIAL COVENANTS

The Company and OTP were in compliance with the financial covenants in these debt agreements as of December 31, 2016.

No Credit or Note Purchase Agreement contains 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.

The Company's and OTP's borrowing agreements are subject to certain financial covenants. Specifically:

- Under the Otter Tail Corporation Credit Agreement, the Term Loan Agreement and the 2016 Note Purchase Agreement, the Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis) as provided in the agreements.
- Under the 2016 Note Purchase Agreement, the Company may not permit its Priority Indebtedness to exceed 10% of its Total Capitalization. The Company had no Priority Indebtedness outstanding as of December 31, 2016.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.
- Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.
- Under the 2013 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, each as provided in the 2013 Note Purchase Agreement. OTP had no Priority Indebtedness outstanding as of December 31, 2016.

11. Pension Plan and Other Postretirement Benefits

For valuation of the Company's pension and other postretirement benefit plans' projected benefit obligations as of December 31, 2016, the Company adopted updated and modified mortality tables and an updated and modified mortality improvement scale that projects lower mortality improvements in the future for plan participants. The adoption of the updated and modified mortality tables and mortality improvement scale in 2016 decreased the Company's pension and other postretirement benefit obligations from projected benefit obligations that would have been rendered using the mortality tables the Company had been using since 2014. Although the adoption of the updated and modified tables and improvement scale will have the effect of decreasing the estimated and recognized cost of future benefit payments in the near term, the ultimate cost recognized will be determined by the actual level and duration of future benefit payments.

PENSION PLAN

The Company's noncontributory funded pension plan covers substantially all corporate employees and OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2013, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the plan. The plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. The Company reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested.

The pension plan has a trustee who is responsible for pension payments to retirees and a separate pension fund manager responsible for managing the plan's assets. An independent actuary assists the Company in performing the necessary actuarial valuations for the plan.

The plan assets consist of common stock and bonds of public companies, U.S. government securities, cash and cash equivalents and alternative investments. None of the plan assets are invested in common stock or debt securities of the Company.

The following table lists components of net periodic pension benefit cost for the year ended December 31:

(in thousands)	2016	2015	2014
Service Cost–			
Benefit Earned During the Period	**$ 5,518**	$ 6,059	$ 4,666
Interest Cost on Projected Benefit Obligation	**14,195**	13,344	13,111
Expected Return on Assets	**(19,454)**	(18,383)	(16,743)
Amortization of Prior Service Cost:			
From Regulatory Asset	**189**	188	257
From Other Comprehensive Income *(1)*	**5**	5	7
Amortization of Net Actuarial Loss:			
From Regulatory Asset	**5,153**	6,676	3,400
From Other Comprehensive Income *(1)*	**127**	171	83
Net Periodic Pension Cost	**$ 5,733**	$ 8,060	$ 4,781

(1) Corporate cost included in Other Nonelectric Expenses.

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2016	2015	2014
Discount Rate	**4.76%**	4.35%	5.30%
Long-Term Rate of Return on Plan Assets	**7.75%**	7.75%	7.75%
Rate of Increase in Future Compensation Level	**3.13%**	3.13%	3.13%

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2016	2015
Regulatory Assets:		
Unrecognized Prior Service Cost	**$ 141**	$ 329
Unrecognized Actuarial Loss	**98,039**	101,974
Total Regulatory Assets	**$ 98,180**	$ 102,303
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	**$ 12**	$ 16
Unrecognized Actuarial Loss	**406**	820
Total Accumulated Other Comprehensive Loss	**$ 418**	$ 836
Noncurrent Liability	**$ 60,292**	$ 69,101

Funded status as of December 31:

(in thousands)	2016	2015
Accumulated Benefit Obligation	**$ (281,414)**	$ (268,387)
Projected Benefit Obligation	**$ (314,637)**	$ (302,740)
Fair Value of Plan Assets	**254,345**	233,639
Funded Status	**$ (60, 292)**	$ (69,101)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations over the two-year period ended December 31, 2016:

(in thousands)	2016	2015
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	**$ 233,639**	$ 244,589
Actual Return on Plan Assets	**23,794**	(9,160)
Discretionary Company Contributions	**10,000**	10,000
Benefit Payments	**(13,088)**	(11,790)
Fair Value of Plan Assets at December 31	**$ 254,345**	$ 233,639
Estimated Asset Return	**10.1%**	(3.7)%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	**$ 302,740**	$ 311,650
Service Cost	**5,518**	6,059
Interest Cost	**14,195**	13,344
Benefit Payments	**(13,088)**	(11,790)
Actuarial Loss (Gain)	**5,272**	(16,523)
Projected Benefit Obligation at December 31	**$ 314,637**	$ 302,740

Weighted average assumptions used to determine benefit obligations at December 31:

	2016	2015
Discount Rate	**4.60%**	4.76%
Rate of Increase in Future Compensation Level	**3.00%**	3.13%

The assumed rate of return on pension fund assets used for the determination of 2017 net periodic pension cost is 7.50%. The assumed long-term rate of return on plan assets is 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 Company reviews its rate of return on plan asset assumptions annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with the Company's pension plan investment advisors, as well as input from actuaries who work with the pension plan.

Market-related value of plan assets—The Company's expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The Company bases actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

Measurement Dates:	2016	2015
Net Periodic Pension Cost	**January 1, 2016**	January 1, 2015
End of Year Benefit Obligations	**January 1, 2016 projected to December 31, 2016**	January 1, 2015 projected to December 31, 2015
Market Value of Assets	**December 31, 2016**	December 31, 2015

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2017 are:

(in thousands)	2017
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 120
Amortization of Unrecognized Actuarial Loss	5,090
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	3
Amortization of Unrecognized Actuarial Loss	125
Total Estimated Amortization	$ 5,338

Cash flows—The Company had no minimum funding requirement as of December 31, 2016 and will continue to evaluate if discretionary plan contributions will be made in 2017.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

(in thousands)					Years
2017	**2018**	**2019**	**2020**	**2021**	**2022–2026**
$13,413	$14,140	$14,806	$15,564	$16,335	$92,083

The following objectives guide the investment strategy of the Company's pension plan (the Plan):

- 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 (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 Plan must be in the best interest of plan participants and their beneficiaries.
- The primary objective of the Plan is to provide a source of retirement income for its participants and beneficiaries.
- The near-term primary financial objective of the Plan is to improve the funded status of the Plan.
- A secondary financial objective is to minimize pension funding and expense volatility where possible.

The asset allocation strategy developed by the Company's Retirement Plans Administration Committee (the Committee) is based on the current needs of the Plan and the objectives listed above. An asset/liability review is conducted annually or as often as necessary to assess the impact of various asset allocations on funded status and other financial variables. The current needs of the Plan, the overall investment objectives above, the investment preferences and risk tolerance of the Committee and the desired degree of diversification suggest the need for an investment allocation including multiple asset classes.

The asset allocation in the table below contains guideline percentages, at market value, of the total Plan invested in various asset classes. The Permitted Range is a guide and will at times not reflect the actual asset allocation as this will be dictated by market conditions, the independent actions of the Committee and/or Investment Managers and required cash flows to and from the Plan. The Permitted Range anticipates this fluctuation and provides flexibility for the Investment Managers' portfolios to vary around the target without the need for immediate rebalancing. The Investment Manager will proactively monitor the asset allocation and will direct the purchases and sales to remain within the stated ranges.

The policy of the Plan is to invest assets in accordance with the allocations shown below:

Asset Class / PBO Funded Status	Permitted Range			
	< 100% PBO	100% PBO	105% PBO	>=110% PBO
Equity	30%–65%	25%–60%	20%–55%	15%–50%
Investment Grade Fixed Income	35%–75%	40%–80%	45%–85%	50%–90%
Below Investment Grade Fixed Income*	0%–15%	0%–15%	0%–15%	0%–15%
Other**	0%–20%	0%–20%	0%–20%	0%–20%

** Includes (but not limited to) High Yield Bond Fund and Emerging Markets Debt funds.*
*** Other category may include cash, alternatives, and/or other investment strategies that may be classified other than equity or fixed income, such as the Dynamic Asset Allocation fund.*

The Company's pension plan asset allocations at December 31, 2016 and 2015, by asset category are as follows:

Asset Allocation	2016	2015
Large Capitalization Equity Securities	**21.4%**	21.2%
International Equity Securities	**22.0%**	21.6%
Small and Mid-Capitalization Equity Securities	**9.0%**	8.1%
SEI Dynamic Asset Allocation Fund	**5.4%**	5.6%
Equity Securities	**57.8%**	56.5%
Fixed-Income Securities and Cash	**34.3%**	35.8%
Other—SEI Energy Debt Collective Fund	**4.1%**	3.6%
Other—SEI Special Situation Collective Investment Trust	**3.8%**	4.1%
	100.0%	100.0%

The following table presents the Company's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy and assets measured using the NAV practical expedient to fair valuation as of December 31:

(in thousands)	2016	2015
Assets in Level 1 of the Fair Value Hierarchy	**$ 234,303**	$ 215,676
SEI Energy Debt Collective Fund at NAV	**10,441**	8,342
SEI Special Situation Collective Investment Trust Fund at NAV *(1)*	**9,601**	9,621
Total Assets	**$ 254,345**	$ 233,639

(1) On December 30, 2016 the Company instructed the pension fund manager to sell the pension fund investment in the SEI Special Situation Collective Investment Trust Fund. The cash value of the investment on settlement of the sale in January 2017 was $9,679,000.

Fair Value Measurements of Pension Fund Assets
ASC 715, *Compensation—Retirement Benefits*, requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35.

The following table presents, the Company's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy as of December 31:

(in thousands)	2016	2015
Large Capitalization Equity Securities Mutual Fund	**$ 54,483**	$ 49,513
International Equity Securities Mutual Funds	**55,916**	50,504
Small and Mid-Capitalization Equity Securities Mutual Fund	**23,011**	18,823
SEI Dynamic Asset Allocation Mutual Fund	**13,622**	13,004
Fixed Income Securities Mutual Funds	**87,268**	83,830
Cash Management—Money Market Fund	**3**	2
Total Assets	**$ 234,303**	$ 215,676

The investments held by the SEI Special Situation Collective Investment Trust on December 31, 2016 and 2015 consisted of investments primarily in hedge funds that pursue alternative strategies, private equity funds and hybrid funds, as well as investments directly in other securities and financial instruments, with the objective of achieving high returns balanced against an appropriate level of volatility and market exposure over a full market cycle. The NAV of the SEI Special Situations Collective Investment Trust is determined by using the fair value of the portfolio as of the close of business at the end of the year. The fair value of the fund is calculated independently by the fund's administrator and is reviewed by the Company.

The investments held by the SEI Energy Debt Collective Fund on December 31, 2016 and 2015 consist mainly of below investment grade high yielding 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 Company invested $10.0 million in the SEI Energy Debt Fund in July 2015. 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). The fund's assets are valued as of the close of business on the last business day of each calendar month and are available 30 days after the end of a calendar quarter. 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, as determined by the investment manager in its sole discretion. The Company reviews and verifies the reasonableness of the year-end valuations.

EXECUTIVE SURVIVOR AND SUPPLEMENTAL RETIREMENT PLAN (ESSRP)
The ESSRP is an unfunded, nonqualified benefit plan for executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period.

Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

The following table lists components of net periodic pension benefit cost for the year ended December 31:

(in thousands)	2016	2015	2014
Service Cost–Benefit Earned During the Period	**$ 252**	$ 189	$ 51
Interest Cost on Projected Benefit Obligation	**1,667**	1,523	1,520
Amortization of Prior Service Cost:			
From Regulatory Asset	**16**	16	22
From Other Comprehensive Income *(1)*	**38**	38	51
Amortization of Net Actuarial Loss:			
From Regulatory Asset	**293**	334	142
From Other Comprehensive Income *(2)*	**446**	602	46
Net Periodic Pension Cost	**$ 2,712**	$ 2,702	$ 1,832
(1) Amortization of Prior Service Costs from Other Comprehensive Income Charged to:			
Electric Operation and Maintenance Expenses	*$ 15*	*$ 15*	*$ 20*
Other Nonelectric Expenses	*23*	*23*	*31*
(2) Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:			
Electric Operation and Maintenance Expenses	*$ 272*	*$ 310*	*$ 132*
Other Nonelectric Expenses	*174*	*292*	*(86)*

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2016	2015	2014
Discount Rate	**4.76%**	4.35%	5.30%
Rate of Increase in Future Compensation Level	**3.13%**	3.15%	3.18%

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2016	2015
Regulatory Assets:		
Unrecognized Prior Service Cost	**$ 58**	$ 75
Unrecognized Actuarial Loss	**2,890**	2,936
Total Regulatory Assets	**$ 2,948**	$ 3,011
Projected Benefit Obligation Liability—Net Amount Recognized	**$ (37,335)**	$ (35,811)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	**$ 134**	$ 172
Unrecognized Actuarial Loss	**5,915**	5,815
Total Accumulated Other Comprehensive Loss	**$ 6,049**	$ 5,987

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2016 and a statement of the funded status as of December 31 of both years:

(in thousands)	2016	2015
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	**$ —**	$ —
Actual Return on Plan Assets	**—**	—
Employer Contributions	**1,188**	1,119
Benefit Payments	**(1,188)**	(1,119)
Fair Value of Plan Assets at December 31	**$ —**	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	**$ 35,811**	$ 35,650
Service Cost	**252**	189
Interest Cost	**1,667**	1,523
Benefit Payments	**(1,188)**	(1,119)
Plan Amendments	**—**	—
Actuarial Loss (Gain)	**793**	(432)
Projected Benefit Obligation at December 31	**$ 37,335**	$ 35,811

Weighted average assumptions used to determine benefit obligations at December 31:

	2016	2015
Discount Rate	**4.60%**	4.76%
Rate of Increase in Future Compensation Level	**3.00%**	3.13%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2017 are:

(in thousands)	2017
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 16
Amortization of Unrecognized Actuarial Loss	285
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	38
Amortization of Unrecognized Actuarial Loss	440
Total Estimated Amortization	$ 779

Cash flows—The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

(in thousands)					Years
2017	2018	2019	2020	2021	2022–2026
$1,253	$1,487	$1,562	$1,544	$1,754	$12,700

OTHER POSTRETIREMENT BENEFITS

The Company provides a portion of health insurance and life insurance benefits for retired OTP and corporate employees. Substantially all of the Company's electric utility and corporate employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. There are no plan assets. The following table lists components of net periodic postretirement benefit cost for the year ended December 31:

(in thousands)	2016	2015	2014
Service Cost–Benefit Earned During the Period	**$ 1,301**	$ 1,297	$ 1,055
Interest Cost on Projected Benefit Obligation	**2,503**	2,097	2,200
Amortization of Prior Service Cost			
From Regulatory Asset	**134**	205	205
From Other Comprehensive Income *(1)*	**3**	5	5
Amortization of Net Actuarial Loss			
From Regulatory Asset	**379**	—	—
From Other Comprehensive Income *(1)*	**9**	—	—
Net Periodic Postretirement Benefit Cost	**$ 4,329**	$ 3,604	$ 3,465
Effect of Medicare Part D Subsidy	**$ (923)**	$ (1,487)	$ (948)

(1) Corporate cost included in Other Nonelectric Expenses.

Weighted average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2016	2015	2014
Discount Rate	**4.57%**	4.20%	5.10%

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2016	2015
Regulatory Asset:		
Unrecognized Prior Service Cost	**$ (4)**	$ 129
Unrecognized Net Actuarial Loss	**13,586**	1,289
Net Regulatory Asset	**$ 13,582**	$ 1,418
Projected Benefit Obligation Liability—		
Net Amount Recognized	**$ (62,571)**	$ (48,730)
Accumulated Other Comprehensive (Income) Loss:		
Unrecognized Prior Service Cost	**$ 4**	$ 8
Unrecognized Net Actuarial Gain	**(171)**	(347)
Accumulated Other Comprehensive Income	**$ (167)**	$ (339)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2016:

(in thousands)	2016	2015
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	**$ —**	$ —
Actual Return on Plan Assets	**—**	—
Company Contributions	**2,825**	2,365
Benefit Payments (Net of Medicare Part D Subsidy)	**(5,908)**	(5,324)
Participant Premium Payments	**3,083**	2,959
Fair Value of Plan Assets at December 31	**$ —**	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	**$ 48,730**	$ 53,638
Service Cost (Net of Medicare Part D Subsidy)	**1,301**	1,297
Interest Cost (Net of Medicare Part D Subsidy)	**2,503**	2,097
Benefit Payments (Net of Medicare Part D Subsidy)	**(5,908)**	(5,324)
Participant Premium Payments	**3,083**	2,959
Actuarial Loss (Gain)	**12,862**	(5,937)
Projected Benefit Obligation at December 31	**$ 62,571**	$ 48,730
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	**$ (47,652)**	$ (46,413)
Expense	**(4,329)**	(3,604)
Net Company Contribution	**2,825**	2,365
Accrued Postretirement Cost at December 31	**$ (49,156)**	$ (47,652)

Weighted average assumptions used to determine benefit obligations at December 31:

	2016	2015
Discount Rate	**4.46%**	4.57%

Assumed healthcare cost-trend rates as of December 31:

	2016	2015
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	**6.01%**	6.16%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	**6.23%**	6.43%
Rate to Which the Cost-Trend Rate is Assumed to Decline	**4.50%**	4.50%
Year the Rate Reaches the Ultimate Trend Rate	**2038**	2038

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2016 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 7,151	$ (7,492)
Effect on Total of Service and Interest Cost	$ 653	$ (519)
Effect on Expense	$ 1,454	$ (907)

Measurement Dates:	2016	2015
Net Periodic Postretirement Benefit Cost	**January 1, 2016**	January 1, 2015
End of Year Benefit Obligations	**January 1, 2016 projected to December 31, 2016**	January 1, 2015 projected to December 31, 2015

The estimated net amounts of unrecognized prior service cost to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2017 are:

(in thousands)	2017
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ —
Amortization of Unrecognized Actuarial Loss	932
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	—
Amortization of Unrecognized Actuarial Loss	23
Total Estimated Amortization	$ 955

Cash flows—The Company expects to contribute $3.5 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2017. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $416,000 in 2017. The following benefit payments, which reflect expected future service, as appropriate, net of expected Medicare Part D subsidy receipts and participant premium payments, are expected to be paid:

(in thousands)					Years
2017	**2018**	**2019**	**2020**	**2021**	**2022–2026**
$3,512	$3,669	$3,828	$3,912	$4,046	$20,377

401K Plan

The Company sponsors a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans by the Company and its subsidiary companies included in continuing operations totaled $3,877,000 for 2016, $3,602,000 for 2015 and $3,171,000 for 2014.

Employee Stock Ownership Plan

The Company has a stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $647,000 for 2016, $674,000 for 2015 and $696,000 for 2014.

12. Fair Value of Financial Instruments

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 value:

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of December 31, 2016 and December 31, 2015 related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to variable interest rates of LIBOR plus 1.75% and LIBOR plus 1.25%, for the respective entities, which approximate market rates.

Long-Term Debt including Current Maturities—The fair value of the Company's and OTP's long-term debt is estimated based on the current market indications of rates available to the Company for the issuance of debt. The fair value measurements of the Company's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820.

	December 31, 2016		December 31, 2015	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$ —	$ —	$ —	$ —
Short-Term Debt	**(42,883)**	**(42,883)**	(80,672)	(80,672)
Long-Term Debt including Current Maturities	**(538,542)**	**(583,835)**	(496,268)	(561,245)

13. Property, Plant and Equipment

(in thousands)	December 31, 2016	December 31, 2015
Electric Plant in Service		
Production	**$ 891,330**	$ 879,121
Transmission	**410,679**	391,941
Distribution	**466,285**	451,820
General	**92,063**	97,881
Electric Plant in Service	**1,860,357**	1,820,763
Construction Work in Progress	**149,997**	64,117
Total Gross Electric Plant	**2,010,354**	1,884,880
Less Accumulated Depreciation and Amortization	**622,657**	592,001
Net Electric Plant	**$ 1,387,697**	$ 1,292,879
Nonelectric Operations Plant		
Equipment	**$ 155,809**	$ 155,715
Buildings and Leasehold Improvements	**51,323**	41,149
Land	**4,694**	4,479
Nonelectric Operations Plant	**211,826**	201,343
Construction Work in Progress	**3,264**	15,495
Total Gross Nonelectric Plant	**215,090**	216,838
Less Accumulated Depreciation and Amortization	**125,562**	121,903
Net Nonelectric Operations Plant	**$ 89,528**	$ 94,935
Net Plant	**$ 1,477,225**	$ 1,387,814

The estimated service lives for rate-regulated properties is 5 to 82 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

Service Life Range *(years)*	Low	High
Electric Fixed Assets:		
Production Plant	9	82
Transmission Plant	42	70
Distribution Plant	5	68
General Plant	5	50
Nonelectric Fixed Assets:		
Equipment	3	12
Buildings and Leasehold Improvements	7	40

14. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2016, 2015 and 2014) to net income before total income tax expense for the following reasons:

(in thousands)	2016	2015	2014
Tax Computed at Federal Statutory Rate—Continuing Operations	**$ 28,741**	$ 28,081	$ 25,704
Increases (Decreases) in Tax from:			
Federal PTCs	**(7,175)**	(6,962)	(7,517)
State Income Taxes Net of Federal Income Tax Expense	**2,848**	4,945	1,993
North Dakota Wind Tax Credit Amortization—Net of Federal Taxes	**(850)**	(850)	(849)
Corporate-owned Life Insurance	**(680)**	(167)	(354)
Dividend Received/Paid Deduction	**(537)**	(560)	(622)
Section 199 Domestic Production Activities Deduction	**(482)**	—	(1,026)
Investment Tax Credit Amortization	**(350)**	(571)	(597)
Allowance for Funds Used During Construction—Equity	**(280)**	(426)	(505)
Differences Reversing in Excess of Federal Rates	**77**	(1,143)	(106)
Permanent and Other Differences	**(1,231)**	(705)	436
Total Income Tax Expense—Continuing Operations	**$ 20,081**	$ 21,642	$ 16,557
Income Tax Expense—Discontinued Operations—U.S.	**138**	2,991	3,952
Income Tax Expense—Continuing and Discontinued Operations	**$ 20,219**	$ 24,633	$ 20,509
Overall Effective Federal, State and Foreign Income Tax Rate	**24.5%**	29.3%	26.2%
Income Tax Expense From Continuing Operations Includes the Following:			
Current Federal Income Taxes	**$ 1,070**	$ 211	$ 124
Current State Income Taxes	**1,211**	1	5
Deferred Federal Income Taxes	**23,586**	23,050	21,044
Deferred State Income Taxes	**2,589**	6,763	4,347
Federal PTCs	**(7,175)**	(6,962)	(7,517)
North Dakota Wind Tax Credit Amortization—Net of Federal Taxes	**(850)**	(850)	(849)
Investment Tax Credit Amortization	**(350)**	(571)	(597)
Total	**$ 20,081**	$ 21,642	$ 16,557
Total Income Before Income Taxes—Continuing and Discontinued Operations	**$ 82,540**	$ 83,978	$ 78,232

The Company's deferred tax assets and liabilities were composed of the following on December 31:

(in thousands)	2016	2015
Deferred Tax Assets		
Benefit Liabilities	**$ 44,381**	$ 41,788
Federal PTCs	**43,433**	39,505
Retirement Benefits Liabilities	**38,390**	41,958
North Dakota Wind Tax Credits	**32,962**	32,962
Cost of Removal	**31,636**	29,463
Differences Related to Property	**9,876**	10,177
Net Operating Loss Carryforward	**3,865**	22,824
Vacation Accrual	**2,725**	2,500
Investment Tax Credits	**818**	1,109
Other	**7,793**	7,617
Total Deferred Tax Assets	**$ 215,879**	$ 229,903
Deferred Tax Liabilities		
Differences Related to Property	**$ (371,761)**	$ (366,234)
Retirement Benefits Regulatory Asset	**(38,390)**	(41,958)
Excess Tax over Book Pension	**(15,509)**	(13,775)
North Dakota Wind Tax Credits	**(3,654)**	(3,179)
Impact of State Net Operating Losses on Federal Taxes	**(1,352)**	(1,596)
Other	**(11,804)**	(10,830)
Total Deferred Tax Liabilities	**$ (442,470)**	$ (437,572)
Deferred Income Taxes	**$ (226,591)**	$ (207,669)

Federal PTCs are earned as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 3.6% in 2016 compared with 2015. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Schedule of expiration of tax credits and tax net operating losses available as of December 31, 2016:

(in thousands)	Amount	2017	2027-36
United States			
Federal Net Operating Losses	$ —	$ —	$ —
Federal Tax Credits	46,435	—	46,435
State Net Operating Losses	3,865	—	3,865
State Tax Credits	33,993	389	33,604

The carryforward period on a portion of the North Dakota wind tax credits from the Langdon wind project is five years. OTP has adjusted its deferred tax assets and deferred tax credits by $0.4 million for potential unused North Dakota wind tax credits related to the Langdon wind project.

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	2016	2015	2014
Balance on January 1	**$ 468**	$ 222	$ 4,239
Increases Related to Tax Positions for Prior Years	**406**	236	120
Decreases Related to Tax Positions for Prior Years	**—**	—	(4,142)
Increases Related to Tax Positions for Current Year	**114**	10	5
Uncertain Positions Resolved During Year	**(97)**	—	—
Balance on December 31	**$ 891**	$ 468	$ 222

The balance of unrecognized tax benefits as of December 31, 2016 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2016 is not expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in our consolidated statement of income. There was no amount accrued for interest on tax uncertainties as of December 31, 2016.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2016, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2013 for federal and Minnesota and North Dakota state income taxes.

15. Asset Retirement Obligations (AROs)

The Company's AROs are related to OTP's coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. The Company has 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. The Company has no assets legally restricted for the settlement of any of its AROs.

On December 19, 2014 the EPA's rule regulating coal combustion residuals (CCR) went into effect. The final rule regulates CCR as a non-hazardous solid waste under Subtitle D of the Resource Conservation and Recovery Act. In the second quarter of 2015, subsequent to publication of the CCR rule, OTP completed an assessment of its ash handling and storage facilities at Hoot Lake Plant, Coyote Station and Big Stone Plant and determined that it had no immediate obligation under the rules to close or modify any existing ash handling facilities or storage sites but has discontinued the use of one pit at Coyote Station to avoid the potential for future obligations related to this site under the CCR rule. Additionally, OTP identified a slag sluice pond and slag stockpile area at Big Stone Plant that will need to be reclaimed at a future date to comply with the CCR rule. OTP established an ARO liability of approximately $0.5 million for its share of the estimated future costs to reclaim this site. Although identified as a new ARO resulting from the issuance of the CCR rule, the slag sluice pond and slag stockpile are currently in use, so the cost of the new ARO was capitalized. Therefore, the establishment of the ARO will have no impact on current year consolidated operating expenses but will result in an offsetting charge to the removal cost component of the accumulated provision for depreciation on the Company's consolidated balance sheet. Future reclamation costs, when incurred, will be charged against, and reduce, the accumulated ARO liability.

OTP recorded no new AROs in 2016.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for

the years ended December 31, 2016 and 2015 are presented in the following table:

(in thousands)	2016	2015
Asset Retirement Obligations		
Beginning Balance	**$ 8,084**	$ 7,721
New Obligations Recognized	**—**	451
Adjustments Due to Revisions in Cash Flow Estimates	**(103)**	(424)
Accrued Accretion	**360**	336
Settlements	**—**	—
Ending Balance	**$ 8,341**	$ 8,084
Asset Retirement Costs Capitalized		
Beginning Balance	**$ 3,086**	$ 3,059
New Obligations Recognized	**—**	451
Adjustments Due to Revisions in Cash Flow Estimates	**(103)**	(424)
Settlements	**—**	—
Ending Balance	**$ 2,983**	$ 3,086
Accumulated Depreciation—		
Asset Retirement Costs Capitalized		
Beginning Balance	**$ 673**	$ 527
New Obligations Recognized	**—**	—
Adjustments Due to Revisions in Cash Flow Estimates	**—**	—
Depreciation Expense	**122**	146
Settlements	**—**	—
Ending Balance	**$ 795**	$ 673
Settlements	**None**	None
Original Capitalized Asset Retirement Cost—Retired	**$ —**	$ —
Accumulated Depreciation	**—**	—
Asset Retirement Obligation	**$ —**	$ —
Settlement Cost	**—**	—
Gain on Settlement— Deferred Under Regulatory Accounting	**$ —**	$ —

16. Discontinued Operations

On April 30, 2015 the Company sold Foley for $12.0 million in cash, plus $6.3 million in adjustments for working capital and other related items received in October 2015, less $1.0 million in selling expenses. On February 28, 2015 the Company sold the assets of AEV, Inc. for $22.3 million in cash, plus $0.6 million in adjustments for working capital and fixed assets received in October 2015, less $0.8 million in selling expenses. Foley and AEV, Inc. were formerly included in the Company's Construction segment.

On February 8, 2013 the Company completed the sale of substantially all the assets of its dock and boatlift company, formerly included in our Manufacturing segment. On November 30, 2012 the Company completed the sale of the assets of our wind tower manufacturing business. This business was the only remaining entity in the Company's former Wind Energy segment.

The Company's Wind Energy and Construction segments were eliminated as a result of the sales of its wind tower manufacturing business, Foley and AEV, Inc. The financial position, results of operations and cash flows of Foley, AEV, Inc., the Company's wind tower manufacturing business and its dock and boatlift company are reported as discontinued operations in the Company's consolidated financial statements.

Following are summary presentations of the results of discontinued operations for the years ended December 31, 2016, 2015 and 2014:

For the Year Ended December 31, 2016

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
Operating Expenses	**$ 250**	**$ —**	**$ (757)**	**$ 85**	**$ —**	**$ (422)**
Income Tax (Benefit) Expense	**(136)**	**5**	**303**	**(34)**	**—**	**138**
Net (Loss) Income	**$ (114)**	**$ (5)**	**$ 454**	**$ (51)**	**$ —**	**$ 284**

For the Year Ended December 31, 2015

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
Operating Revenues	$ 21,625	$ 2,998	$ —	$ —	$ —	$ 24,623
Operating Expenses	26,839	4,532	(462)	966	(240)	31,635
Asset Impairment Charge	1,000	—	—	—	—	1,000
Interest Expense	177	27	—	—	(204)	—
Other Income (Deductions)	(42)	2	111	—	(2)	69
Income Tax (Benefit) Expense	(921)	(638)	229	(386)	177	(1,539)
Net (Loss) Income from Operations	(5,512)	(921)	344	(580)	265	(6,404)
(Loss) Gain on Disposition Before Taxes	(204)	11,894	—	—	—	11,690
Income Tax (Benefit) Expense on Disposition	(227)	4,757	—	—	—	4,530
Net Gain on Disposition	23	7,137	—	—	—	7,160
Net (Loss) Income	$ (5,489)	$ 6,216	$ 344	$ (580)	$ 265	$ 756

For the Year Ended December 31, 2014

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
Operating Revenues	$ 105,333	$ 44,527	$ —	$ —	$ —	$ 149,860
Operating Expenses	100,826	40,297	19	(180)	(960)	140,002
Asset Impairment Charge	5,605	—	—	—	—	5,605
Interest Expense	510	184	—	—	(694)	—
Other (Deductions) Income	(38)	304	—	277	(4)	539
Income Tax Expense (Benefit)	1,388	1,729	(8)	183	660	3,952
Net (Loss) Income	$ (3,034)	$ 2,621	$ (11)	$ 274	$ 990	$ 840

Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges of $4.4 million in 2015.

In the fourth quarter of 2014 the Company entered into negotiations to sell Foley and, as a result of an impairment indicator, the Company recorded a $5.6 million goodwill impairment charge. This impairment charge was based on the indicated offering price in a signed letter of intent for the purchase of Foley. In the first quarter of 2015, Foley recorded an additional $1.0 million goodwill impairment charge based on adjustments to the carrying value of Foley. The fourth quarter 2014 and first quarter 2015 goodwill impairment losses are reflected in the results of discontinued operations.

Following are summary presentations of the major components of assets and liabilities of discontinued operations as of December 31, 2016 and December 31, 2015:

December 31, 2016

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Total
Current Liabilities	**$ —**	**$ —**	**$ 589**	**$ 774**	**$ 1,363**
Liabilities of Discontinued Operations	**$ —**	**$ —**	**$ 589**	**$ 774**	**$ 1,363**

December 31, 2015

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Total
Current Liabilities	$ —	$ —	$ 1,299	$ 799	$ 2,098
Liabilities of Discontinued Operations	$ —	$ —	$ 1,299	$ 799	$ 2,098

Included in current liabilities of discontinued operations are warranty reserves. Details regarding the warranty reserves follow:

(in thousands)	2016	2015
Warranty Reserve Balance, January 1	**$ 2,103**	$ 2,527
Additional Provision for Warranties Made During the Year	**—**	—
Settlements Made During the Year	**(24)**	(124)
Decrease in Warranty Estimates for Prior Years	**(710)**	(300)
Warranty Reserve Balance, December 31	**$ 1,369**	$ 2,103

The warranty reserve balances as of December 31, 2016 relate entirely to products produced by the Company's former wind tower and dock and boatlift manufacturing companies. Certain products sold by the companies carried one to fifteen year warranties. Although the assets of these companies have been sold and their operating results are reported under discontinued operations in the Company's consolidated statements of income, the Company retains responsibility for warranty claims related to the products they produced prior to the sales of these companies.

Expenses associated with remediation activities of these companies could be substantial. For wind towers, the potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. For example, if the Company is required to cover remediation expenses in addition to regular warranty coverage, the Company could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect the Company's consolidated net income and financial condition.

17. Subsequent Events

Stock Incentive Awards

On February 2, 2017 the following stock incentive awards were granted to officers under the 2014 Incentive Plan:

Award	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Restricted Stock Units Granted	15,900	$ 37.65	25% per year through February 6, 2021
Stock Performance Awards Granted	59,500	$ 31.00	December 31, 2019

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration in certain cases. All restricted stock units granted to executive officers are eligible to receive dividend equivalent payments on all unvested awards over the awards respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The grant-date fair value of each restricted stock unit was the average of the high and low market price per share on the date of grant.

Under the performance share awards the aggregate award for performance at target is 59,500 shares. For target performance the participants would earn an aggregate of 39,667 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance measurement period of January 1, 2017 through December 31, 2019, with the beginning and ending share values based on the average closing price of a share of the Company's common stock for the 20 trading days immediately following January 1, 2017 and the average closing price for the 20 trading days immediately preceding January 1, 2020. The participants would also earn an aggregate of 19,833 common shares for achieving the target set for the Company's 3-year average adjusted return on equity. Actual payment may range from zero to 150% of the target amount, or up to 89,250 common shares. There are no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance measurement period. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC 718, and will be measured over the performance period based on the grant-date fair value of the award.

Under the 2017 Performance Award Agreements, payment and the amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to certain officers who are parties to Executive Employment Agreements with the Company is to be made at target at the date of any such event.

The end of the period over which compensation expense is recognized for the above share-based awards for the individual grantees is the shorter of the indicated vesting period for the respective awards or the date the grantee becomes eligible for retirement as defined in their award agreement.

SUPPLEMENTARY FINANCIAL INFORMATION

Quarterly Information (not audited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings (loss) per common share may not equal total earnings (loss) per common share.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2016	2015*(1)*	2016	2015	2016	2015	2016	2015
Operating Revenues–Continuing Operations	**$ 206,242**	$ 202,841	**$ 203,482**	$ 188,153	**$ 197,175**	$ 200,023	**$ 196,640**	$ 188,787
Operating Income–Continuing Operations	**$ 27,576**	$ 25,025	**$ 27,083**	$ 24,800	**$ 27,284**	$ 29,626	**$ 29,156**	$ 29,763
Net Income (Loss):								
Continuing Operations	**$ 14,490**	$ 13,781	**$ 15,556**	$ 13,657	**$ 14,594**	$ 15,709	**$ 17,397**	$ 15,442
Discontinued Operations	**$ 30**	$ 4,154	**$ 119**	$ (2,221)	**$ 22**	$ (317)	**$ 113**	$ (860)
Total Net Income	**$ 14,520**	$ 17,935	**$ 15,675**	$ 11,436	**$ 14,616**	$ 15,392	**$ 17,510**	$ 14,582
Basic Earnings (Loss) Per Share:								
Continuing Operations	**$ .38**	$ .37	**$ .41**	$ .37	**$ .38**	$ .42	**$ .45**	$ .41
Discontinued Operations	**$ —**	$ .11	**$ —**	$ (.06)	**$ —**	$ (.01)	**$ —**	$ (.02)
Total Basic Earnings Per Share	**$ .38**	$ .48	**$ .41**	$ .31	**$ .38**	$ .41	**$ .45**	$ .39
Diluted Earnings (Loss) Per Share:								
Continuing Operations	**$ .38**	$ .37	**$ .41**	$ .36	**$ .37**	$ .42	**$ .44**	$ .41
Discontinued Operations	**$ —**	$ .11	**$ —**	$ (.06)	**$ —**	$ (.01)	**$ —**	$ (.02)
Total Diluted Earnings Per Share	**$ .38**	$ .48	**$ .41**	$ .30	**$ .37**	$ .41	**$ .44**	$ .39
Dividends Declared Per Common Share	**$ .3125**	$ .3075	**$ .3125**	$ .3075	**$ .3125**	$ .3075	**$ .3125**	$ .3075
Price Range:								
High	**29.73**	33.44	**33.50**	32.76	**36.42**	28.34	**42.55**	28.76
Low	**25.80**	30.60	**27.77**	26.14	**32.89**	24.82	**33.08**	25.20
Average Number of Common Shares Outstanding—Basic	**37,937**	37,243	**38,179**	37,433	**38,833**	37,575	**39,236**	37,728
Average Number of Common Shares Outstanding—Diluted	**38,045**	37,498	**38,321**	37,653	**39,006**	37,795	**39,552**	37,868

(1) Results include pre-tax goodwill impairment charges of $1.0 million at Foley in discontinued operations.

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, 2016, 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, 2016.

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, 2016 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 Annual 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, 2016. 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, 2016, 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 Annual 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 on page 47.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under "Election of Directors" in the Company's definitive Proxy Statement for the 2017 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A hereto. The information regarding Section 16 reporting is incorporated by reference to the information under "Security Ownership of Directors and Officers—Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's definitive Proxy Statement for the 2017 Annual Meeting. The information required by this Item regarding the Company's procedures for recommending nominees to the board of directors is incorporated by reference to the information under "Meetings and Committees of the Board of Directors—Corporate Governance Committee" in the Company's definitive Proxy Statement for the 2017 Annual Meeting. The information required by this Item in regard to the Audit Committee and the Company's Audit Committee financial experts is incorporated by reference to the information under "Meetings and Committees of the Board of Directors—Audit Committee" in the Company's definitive Proxy Statement for the 2017 Annual Meeting.

The Company has adopted a code of conduct 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 conduct is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of conduct 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 Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under "Compensation Discussion and Analysis," "Report of Compensation Committee," "Executive Compensation" and "Director Compensation" in the Company's definitive Proxy Statement for the 2017 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" and "Security Ownership of Directors and Officers" in the Company's definitive Proxy Statement for the 2017 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2016 about the Company's common stock that may be issued under all of 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:			
2014 Stock Incentive Plan	417,193 *(1)*	$ 0.00	1,356,811 *(2)*
1999 Stock Incentive Plan	14,135 *(3)*	$ 0.00	— *(4)*
1999 Employee Stock Purchase Plan	—	N/A	384,159 *(5)*
Equity compensation plans not approved by security holders	—	—	—
Total	431,328	$ 0.00	1,740,790

(1) Includes 122,250, 126,450 and 89,291 performance based share awards granted in 2016, 2015 and 2014, respectively, 78,745 restricted stock units outstanding as of December 31, 2016, and 457 stock units as part of the director deferred compensation program, and excludes 48,789 shares of restricted stock issued under the 2014 Stock Incentive Plan.

(2) The 2014 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) Includes 11,250 restricted stock units outstanding as of December 31, 2016, and 2,885 stock units as part of the director deferred compensation program, and excludes 4,725 shares of restricted stock issued under the 1999 Stock Incentive Plan.

(4) The 1999 Stock Incentive Plan provided 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. The 1999 Stock Incentive Plan expired by its terms on December 13, 2013 and no more awards may be granted thereunder.

(5) Shares are issued based on employee's election to participate in the plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information under "Policy and Procedures Regarding Transactions with Related Persons," "Election of Directors" and "Meetings and Committees of the Board of Directors" in the Company's definitive Proxy Statement for the 2017 Annual Meeting.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under "Ratification of Independent Registered Public Accounting Firm—Fees" and "Ratification of Independent Registered Public Accounting Firm—Pre-Approval of Audit/Non-Audit Services Policy" in the Company's definitive Proxy Statement for the 2017 Annual Meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of documents filed as part of this report:

1. Financial Statements **PAGE**

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Consolidated Balance Sheets, December 31, 2016 and 2015 . . . 48
Consolidated Statements of Income for the Three Years Ended December 31, 2016 . . . 50
Consolidated Statements of Comprehensive Income for the Three Years Ended December 31, 2016 . . . 51
Consolidated Statements of Common Shareholders' Equity for the Three Years Ended December 31, 2016 . . . 52
Consolidated Statements of Cash Flows for the Three Years Ended December 31, 2016 . . . 53
Consolidated Statements of Capitalization, December 31, 2016 and 2015 . . . 54
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2. Financial Statement Schedules

SCHEDULE 1— CONDENSED FINANCIAL INFORMATION OF REGISTRANT

OTTER TAIL CORPORATION (PARENT COMPANY)

Condensed Balance Sheets, December 31

(in thousands)	2016	2015
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 6,218	$ —
Accounts Receivable	12	38
Accounts Receivable from Subsidiaries	1,706	2,311
Interest Receivable from Subsidiaries	141	175
Income Taxes Receivable	662	4,000
Notes Receivable from Subsidiaries	1,671	5,645
Other	936	1,096
Total Current Assets	11,346	13,265
Investments in Subsidiaries	692,723	713,344
Notes Receivable from Subsidiaries	79,843	72,560
Deferred Income Taxes	35,387	37,406
Other Assets	29,079	26,957
Total Assets	$ 848,378	$ 863,532
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$ —	$ 59,666
Current Maturities of Long-Term Debt	231	52,422
Accounts Payable to Subsidiaries	5,958	5,959
Notes Payable to Subsidiaries	38,519	99,467
Other	5,838	6,035
Total Current Liabilities	50,546	223,549
Other Noncurrent Liabilities	32,556	34,015
Commitments and Contingencies		
Capitalization		
Long-Term Debt, Net of Current Maturities	95,172	945
Common Shareholder Equity	670,104	605,023
Total Capitalization	765,276	605,968
Total Liabilities and Equity	$ 848,378	$ 863,532

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)

Condensed Statements of Income—For the Years Ended December 31

(in thousands)	2016	2015	2014
Operating Loss			
Revenue	**$ —**	$ —	$ —
Operating Expenses	**9,689**	10,188	12,593
Operating Loss	**(9,689)**	(10,188)	(12,593)
Other Income (Expense)			
Equity Income in Earnings of Subsidiaries	**67,047**	66,067	64,926
Interest Charges	**(6,817)**	(6,786)	(6,326)
Interest Charges to Subsidiaries	**(173)**	(193)	(117)
Interest Income from Subsidiaries	**4,897**	4,786	4,980
Other Income	**1,621**	421	1,379
Total Other Income	**66,575**	64,295	64,842
Income Before Income Taxes	**56,886**	54,107	52,249
Income Tax Benefit	**(5,435)**	(5,238)	(5,474)
Net Income	**$ 62,321**	$ 59,345	$ 57,723

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)

Condensed Statements of Cash Flows—For the Years Ended December 31

(in thousands)	2016	2015	2014
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	**$ 83,296**	$ 53,958	$ 47,697
Cash Flows from Investing Activities			
Return of Capital (Investment in Subsidiaries)	**9,912**	(88,079)	(44,000)
Debt Issued to Subsidiaries	**(3,309)**	(12,592)	(7,662)
Cash Provided by (Used in) Investing Activities	**106**	(11)	(44)
Net Cash Provided by (Used in) Investing Activities	**6,709**	(100,682)	(51,706)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**(428)**	213	215
Net Short-Term (Repayments) Borrowings	**(59,666)**	48,812	10,854
(Repayments to) Borrowings from Subsidiaries	**(60,948)**	32,249	4,656
Proceeds from Issuance of Common Stock	**44,435**	14,233	26,259
Common Stock Issuance Expenses	**(562)**	(451)	(673)
Payments for Retirement of Capital Stock	**(104)**	(1,596)	(590)
Proceeds from the Issuance of Long-Term Debt	**130,000**	—	—
Short-Term and Long-Term Debt Issuance Expenses	**(723)**	(312)	(170)
Payments for Retirement of Long-Term Debt	**(87,547)**	(201)	(188)
Dividends Paid and Other Distributions	**(48,244)**	(46,223)	(44,261)
Net Cash (Used in) Provided by Financing Activities	**(83,787)**	46,724	(3,898)
Net Change in Cash and Cash Equivalents	**6,218**	—	(7,907)
Cash and Cash Equivalents at Beginning of Period	**—**	—	7,907
Cash and Cash Equivalents at End of Period	**$ 6,218**	$ —	$ —

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
Notes to Condensed Financial Statements
For the years ended December 31, 2016, 2015 and 2014

Incorporated by reference are Otter Tail Corporation's consolidated statements of comprehensive income and common shareholders' equity in Part II, Item 8.

Basis of Presentation

The condensed financial information of Otter Tail Corporation is presented to comply with Rule 12-04 of Regulation S-X. The unconsolidated condensed financial statements do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read with the consolidated financial statements and related notes included in this Annual Report on Form 10-K.

Otter Tail Corporation's investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income (loss) from operations of the subsidiaries is reported on a net basis as equity income (loss) in earnings of subsidiaries.

Related Party Transactions

As of December 31, 2016:

(in thousands)	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 1,572	$ —	$ —	$ —	$ 10	$ —
Vinyltech Corporation	3	20	—	11,500	—	15,951
Northern Pipe Products, Inc.	—	10	—	5,943	—	6,560
BTD Manufacturing, Inc.	—	92	—	52,000	—	2,342
Wind Tower Business	—	—	1,441	—	—	—
Dock and Boatlift Business	—	—	230	—	—	—
T.O. Plastics, Inc.	—	19	—	10,400	—	12,378
Varistar Corporation	60	—	—	—	5,948	1,288
Otter Tail Assurance Limited	71	—	—	—	—	—
	$ 1,706	$ 141	$ 1,671	$ 79,843	$ 5,958	$ 38,519

As of December 31, 2015:

(in thousands)	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 1,928	$ —	$ —	$ —	$ 11	$ —
Vinyltech Corporation	—	32	—	8,500	—	14,844
Northern Pipe Products, Inc.	—	8	—	3,160	—	7,088
BTD Manufacturing, Inc.	13	107	3,924	53,500	—	—
Wind Tower Business	—	—	1,444	—	—	—
Dock and Boatlift Business	—	—	277	—	—	—
T.O. Plastics, Inc.	—	28	—	7,400	—	6,405
Varistar Corporation	60	—	—	—	5,948	71,130
Otter Tail Assurance Limited	310	—	—	—	—	—
	$ 2,311	$ 175	$ 5,645	$ 72,560	$ 5,959	$ 99,467

Dividends

Dividends paid to Otter Tail Corporation (the Parent) from its subsidiaries were as follows:

(in thousands)	2016	2015	2014
Cash Dividends Paid to Parent by Subsidiaries	$ 77,779	$ 46,188	$ 44,261

See Otter Tail Corporation's notes to consolidated financial statements in Part II, Item 8 for other disclosures.

Other schedules are omitted because of the absence of the conditions under which they are required, because the amounts are insignificant or because the information required is included in the financial statements or the notes thereto.

3. Exhibits

The following Exhibits are filed as part of, or incorporated by reference into, this report.

	Previously Filed		
	File No.	As Exhibit No.	
2-A	8-K filed 7/1/09	2.1	Plan of Merger, dated as of June 30, 2009, by and among Otter Tail Corporation (now known as Otter Tail Power Company), Otter Tail Holding Company (now known as Otter Tail Corporation) and Otter Tail Merger Sub Inc.
2-B			Asset Purchase Agreement, dated as of November 16, 2016, among Otter Tail Power Company, EDF Renewable Development, Inc., Power Partners Midwest, LLC, EDF-RE US Development, LLC and Merricourt Power Partners, LLC.**/***
2-C			Turnkey Engineering, Procurement and Construction Services Agreement, dated as of November 16, 2016, between Otter Tail Power Company and EDF-RE US Development, LLC.**/***
3-A	8-K filed 7/1/09	3.1	Restated Articles of Incorporation.
3-B	8-K filed 7/1/09	3.2	Restated Bylaws.
4-A	8-K filed 8/23/07	4.1	Note Purchase Agreement, dated as of August 20, 2007.
4-A-1	8-K filed 12/20/07	4.3	First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007.
4-A-2	8-K filed 9/15/08	4.1	Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007.
4-A-3	8-K filed 7/1/09	4.2	Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007.
4-B	8-K filed 11/2/12	4.1	Third Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Corporation, the Banks named therein, Bank of America, N.A. and JPMorgan Chase Bank, N.A., as Co-Syndication Agents, KeyBank National Association, as Documentation Agent, U.S. Bank National Association, as administration agent for the Banks and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners.
4-B-1	8-K filed 11/1/13	4.1	First Amendment to Third Amended and Restated Credit Agreement, dated as of October 29, 2013, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West and Union Bank, N.A., as Banks.
4-B-2	8-K filed 11/4/14	4.1	Second Amendment to Third Amended and Restated Credit Agreement, dated as of November 3, 2014, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-B-3	8-K filed 11/3/15	4.1	Third Amendment to Third Amended and Restated Credit Agreement, dated as of October 29, 2015, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-B-4	8-K filed 11/3/16	4.1	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2016, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-C	8-K filed 11/2/12	4.2	Second Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Power Company, the Banks named therein, JPMorgan Chase Bank, N.A. and Bank of America, N.A., as Co-Syndication Agents, KeyBank National Association and CoBank, ACB, as Co-Documentation Agents, U.S. Bank National Association, as administrative agent for the Banks, and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners.
4-C-1	8-K filed 11/1/13	4.2	First Amendment to Second Amended and Restated Credit Agreement, dated as of October 29, 2013, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association and Union Bank, N.A., as Banks.
4-C-2	8-K filed 11/4/14	4.2	Second Amendment to Second Amended and Restated Credit Agreement, dated as of November 3, 2014, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-C-3	8-K filed 11/3/15	4.2	Third Amendment to Second Amended and Restated Credit Agreement, dated as of October 29, 2015, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-C-4	8-K filed 11/3/16	4.2	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of October 31, 2016, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-D	8-K filed 8/3/11	4.1	Note Purchase Agreement, dated as of July 29, 2011, between Otter Tail Power Company and the Purchasers named therein.
4-E	8-K filed 8/16/13	4.1	Note Purchase Agreement dated as of August 14, 2013 between Otter Tail Power Company and the Purchasers named therein.

4-F	8-K filed 2/9/16	4.1	Term Loan Agreement dated as of February 5, 2016 among Otter Tail Corporation, the Banks named therein and JPMorgan Chase Bank, N.A., as administrative agent for the Banks, and J.P. Morgan Securities LLC, as Lead Arranger and Book Runner.
4-G	8-K filed 9/27/16	4.1	Note Purchase Agreement dated as of September 23, 2016 between Otter Tail Corporation and the Purchasers named therein.
10-A	2-55813	5-F	Contract dated April 12, 1973, between the Bureau of Reclamation and the Company.
10-B	2-55813	5-G	Contract dated January 8, 1973, between East River Electric Power Cooperative and the Company.
10-B-1	2-62815	5-E-1	Supplement One dated February 20, 1978.
10-B-2	10-K for year ended 12/31/89	10-E-3	Supplement Two dated June 10, 1983.
10-B-3	10-K for year ended 12/31/90	10-E-4	Supplement Three dated June 6, 1985.
10-B-4	10-K for year ended 12/31/92	10-E-5	Supplement No. Four, dated as of September 10, 1986.
10-B-5	10-K for year ended 12/31/92	10-E-6	Supplement No. Five, dated as of January 7, 1993.
10-B-6	10-K for year ended 12/31/93	10-E-7	Supplement No. Six, dated as of December 2, 1993.
10-C	10-K for year ended 12/31/89	10-F	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).
10-C-1	10-K for year ended 12/31/89	10-F-1	Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-C-2	10-K for year ended 12/31/91	10-F-2	Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-C-3	10-K for year ended 12/31/91	10-F-3	Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-C-4	10-K for year ended 12/31/91	10-F-4	Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-C-5	10-Q for quarter ended 9/30/03	10.1	Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-C-6	10-K for year ended 12/31/92	10-F-5	Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-D	10-Q for quarter ended 6/30/15	10.3	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-E	2-61043	5-H	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).
10-E-1	10-K for year ended 12/31/89	10-H-1	Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-E-2	10-K for year ended 12/31/89	10-H-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.
10-E-3	10-K for year ended 12/31/89	10-H-3	Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-E-4	10-K for year ended 12/31/92	10-H-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.
10-E-5	10-Q for quarter ended 9/30/01	10-A	Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-E-6	10-Q for quarter ended 9/30/03	10.2	Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-F	2-63744	5-I	Coyote Plant Coal Agreement by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company, Minnesota Power & Light Company, and Knife River Coal Mining Company (dated as of January 1, 1978).
10-F-1	10-K for year ended 12/31/92	10-I-1	Addendum, dated as of March 10, 1980, to Coyote Plant Coal Agreement.
10-F-2	10-K for year ended 12/31/92	10-I-2	Amendment (No. 3), dated as of May 28, 1980, to Coyote Plant Coal Agreement.
10-F-3	10-K for year ended 12/31/92	10-I-3	Fourth Amendment, dated as of August 19, 1985, to Coyote Plant Coal Agreement.
10-F-4	10-Q for quarter ended 6/30/93	19-A	Sixth Amendment, dated as of February 17, 1993, to Coyote Plant Coal Agreement.
10-F-5	10-K for year ended 12/31/01	10-I-5	Agreement and Consent to Assignment of the Coyote Plant Coal Agreement.

10-G	10-K for year ended 12/31/12	10-J	Lignite Sales Agreement between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., Northwestern Corporation, dated as of October 10, 2012.**
10-G-1	8-K filed 1/31/14	10.1	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-G-2	8-K filed 3/18/15	10.1	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-H	10-Q for quarter ended 3/31/13	10.1	General Work Construction Agreement, dated as of February 1, 2013, between Otter Tail Power Company, in its capacity as agent for itself, Northwestern Corporation d/b/a NorthWestern Energy and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and Graycor Industrial Constructors Inc.**
10-I	10-Q/A for quarter ended 6/30/13	10.1	Wind Energy Purchase Agreement dated May 9, 2013 between Otter Tail Power Company and Ashtabula Wind III, LLC.**
10-J-1	10-K for year ended 12/31/02	10-N-1	Deferred Compensation Plan for Directors, as amended.*
10-J-1a	10-K for year ended 12/31/10	10-N-1A	First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10-J-1b	8-K filed 4/17/14	10.5	Second Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10-J-2	8-K filed 2/04/05	10.1	Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-J-2a	10-K for year ended 12/31/06	10-N-2a	First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-J-2b	10-K for year ended 12/31/10	10-N-2B	Second Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-J-3	10-Q for quarter ended 9/30/11	10.1	Nonqualified Retirement Plan (2011 Restatement).*
10-J-4	10-Q for quarter ended 9/30/16	10.1	1999 Employee Stock Purchase Plan, As Amended (2016).
10-J-5	8-K filed 4/13/06	10.4	1999 Stock Incentive Plan, As Amended (2006).
10-J-6	8-K filed 4/19/12	10.2	Form of 2012 Restricted Stock Award Agreement for Executive Officers.*
10-J-7	8-K filed 4/19/12	10.4	Form of 2012 Restricted Stock Unit Award Agreement.*
10-J-8	8-K filed 4/13/06	10.1	Form of Restricted Stock Award Agreement for Directors.*
10-J-9	10-K for year ended 12/31/13	10-O-12	2014 Executive Annual Incentive Plan.*
10-J-10	333-195337	4.1	Otter Tail Corporation 2014 Stock Incentive Plan.
10-J-11	8-K filed 4/17/14	10.1	Form of 2014 Performance Award Agreement.*
10-J-12	8-K filed 4/17/14	10.2	Form of 2014 Restricted Stock Award Agreement for Executive Officers.*
10-J-13	8-K filed 4/17/14	10.3	Form of 2014 Restricted Stock Award Agreement for Directors.*
10-J-14			Summary of Non-Employee Director Compensation (2016).
10-J-15	8-K filed 9/26/14	10.1	Amendment to 2014 Performance Award Agreement with Edward J. McIntyre.*
10-J-16	8-K filed 2/11/15	10.1	Form of 2015 Performance Award Agreement (Executives).*
10-J-17	8-K filed 2/11/15	10.2	Form of 2015 Performance Award Agreement (Legacy).*
10-J-18	8-K filed 2/11/15	10.3	Form of 2015 Restricted Stock Unit Award Agreement (Executives).*
10-J-19	8-K filed 2/11/15	10.4	Form of 2015 Restricted Stock Unit Award Agreement (Legacy).*
10-J-20	8-K filed 2/11/15	10.5	Otter Tail Corporation Executive Restoration Plus Plan, as Amended and Restated.
10-J-21	8-K filed 4/15/15	10.2	Form of 2015 Restricted Stock Award Agreement for Directors.*
10-K	8-K filed 5/11/15	1.1	Distribution Agreement dated May 11, 2015, between Otter Tail Corporation and J.P. Morgan Securities LLC.
10-L-1	10-K for year ended 12/31/12	10-O-1	Executive Employment Agreement, Kevin Moug.*
10-L-2	10-K for year ended 12/31/12	10-O-2	Executive Employment Agreement, George Koeck.*
10-M-1	10-K for year ended 12/31/10	10-Q-3	Change in Control Severance Agreement, Kevin G. Moug.*
10-M-2	10-K for year ended 12/31/10	10-Q-4	Change in Control Severance Agreement, George Koeck.*
10-M-3	10-K for year ended 12/31/11	10-Q-5	Change in Control Severance Agreement, Chuck MacFarlane.*
10-M-4	10-Q for quarter ended 9/30/14	10.3	Change in Control Severance Agreement, Timothy Rogelstad.*
10-M-5	10-Q for quarter ended 9/30/14	10.6	Change in Control Severance Agreement, Paul Knutson.*
10-M-6	10-K for year ended 12/31/15	10-R-6	Change in Control Severance Agreement, John Abbott.*

10-N	8-K filed 4/15/15	10.1	Otter Tail Corporation Executive Severance Plan.*
12.1			Calculation of Ratios of Earnings to Fixed Charges and Preferred Dividends.
21-A			Subsidiaries of Registrant.
23-A			Consent of Deloitte & Touche LLP.
24-A			Powers of Attorney.
31.1			Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2			Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2			Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101			Financial statements from the Annual Report on Form 10-K of Otter Tail Corporation for the year ended December 31, 2016, formatted in Extensible Business Reporting Language: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Common Shareholders' Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Consolidated Statements of Capitalization, (vii) the Notes to Consolidated Financial Statements and (viii) Schedule I.

**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.*

****Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company hereby undertakes to furnish copies of any of the omitted schedules and exhibits to the Securities and Exchange Commission upon request.*

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

ITEM 16. FORM 10-K SUMMARY

None

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OTTER TAIL CORPORATION

By /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Senior Vice President
(authorized officer and principal financial officer)

Dated: February 22, 2017

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:

Charles S. MacFarlane
President and Chief Executive Officer
(principal executive officer) and Director

Kevin G. Moug
Chief Financial Officer and Senior Vice President
(principal financial and accounting officer)

Nathan I. Partain
Chairman of the Board and Director

Karen M. Bohn, Director

John D. Erickson, Director

Steven L. Fritze, Director

Kathryn O. Johnson, Director

Timothy J. O'Keefe, Director

Joyce Nelson Schuette, Director

James B. Stake, Director

By /s/ Charles S. MacFarlane
Charles S. MacFarlane
Pro Se and Attorney-in-Fact
Dated February 22, 2017

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 Internet 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. 2016 dividends were $1.25 per share, and the year-end yield was 3.1 percent. Total shareholder return grew at a compounded average annual rate of 7.5 percent for the past ten years.

Dividend Reinvestment and Share Purchase Plan

Our Dividend Reinvestment and Share Purchase Plan provides shareholders of record with a convenient method for purchasing shares of Otter Tail Corporation common stock. Approximately 83 percent of eligible shareowners holding approximately 12 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. 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 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 direct registration system (DRS) as a method of holding your shares in book-entry form, which eliminates the need to hold stock certificates.

2017 Annual Meeting of Shareholders

Monday, April 10, 2017 • 10:00 A.M., Central Daylight Time
Bigwood Event Center
Country Inn & Suites
925 Western Avenue
Fergus Falls, Minnesota

2017 Common Dividend Dates

EX-DIVIDEND	RECORD	PAYMENT
February 13	February 15	March 10
May 11	May 15	June 10
August 11	August 15	September 9
November 13	November 15	December 9

Key Statistics

NASDAQ . . . . . OTTR
Senior unsecured debt ratings
Otter Tail Corporation:
Fitch . . . . . BBB-/stable
Moody's Investor Service Baa2/stable
Standard & Poor's . . . . . BBB-/stable
Otter Tail Power Company:
Fitch . . . . . BBB+/stable
Moody's Investor Service A3/stable
Standard & Poor's . . . . . BBB/stable
Year-end stock price $40.80
Year-end market-to-book ratio 2.4
Annual dividend yield 3.1%
Shares outstanding . . . . . 39.3 million
Market capitalization (as of December 31, 2016) . . . . . $1.6 billion
2016 average daily trading volume 109,897
Institutional holdings
(shares as of December 31, 2016) . . . . . 18.7 million

Transfer Agent

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

Shareholder Services

Otter Tail Corporation
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: 800-664-1259 or 218-739-8479
Fax: 218-998-3165
Email: sharesvc@ottertail.com

Left to right: Kevin Moug, Cris Oehler, Paul Knutson, Charles MacFarlane, Timothy Rogelstad, George Koeck, and John Abbott

EXECUTIVE LEADERSHIP

DIRECTORS

DIRECTORS

NATHAN I. PARTAIN
Chairman of the Board of Directors
Chicago, Illinois
President and Chief Investment Officer, Duff & Phelps Investment Management Co.; President, Chief Executive Officer, and Chief Investment Officer, DNP Select Income Fund, Inc. (closed-end utility income fund)

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

JOHN D. ERICKSON
Fergus Falls, Minnesota
Former President and Chief Executive Officer, Otter Tail Corporation (utility and diversified businesses)

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

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

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

TIMOTHY J. O'KEEFE
C/CG—Grand Forks, North Dakota
Retired Executive Vice President, University of North Dakota Alumni Association; Retired Chief Executive Officer, University of North Dakota Foundation (nonprofit)

JOYCE NELSON SCHUETTE
A/C—Walker, Minnesota
Retired Managing Director and Investment Banker, Piper Jaffray & Co. (financial services)

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

Committees:
A—Audit
C—Compensation
CG—Corporate Governance

EXECUTIVE LEADERSHIP

CHARLES S. MACFARLANE
President and Chief Executive Officer

KEVIN G. MOUG
Chief Financial Officer and Senior Vice President

GEORGE A. KOECK
Senior 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

CRIS M. OEHLER
Vice President, Corporate Communication

PAUL L. KNUTSON
Vice President, Human Resources

ABOUT THE COVER

T.O. Plastics Product Packagers **Hussein Mohamed** (cover) and **Lourdes Mendoza** ensure proper packaging for horticulture containers, which account for 63 percent of the company's total sales.

Vinyltech Assistant Controller **Heather Carver** and Purchasing and Environmental Agent **Nathan Hiatt** focus on operational excellence even before raw material arrives.

Northern Pipe Products Lead Regrind Associate **Cody Peters** (cover) and Shipping Lift Truck Operator **Alex Kostolami** take great care in handling millions of pounds of pipe a year.

BTD-Georgia Manufacturing Lead, Paint, **Baltazar Perez** and Daily Planner **Sheryl Norton** have customer satisfaction top of mind before, during, and after production.

Otter Tail Power Company Senior Resource Planners **Debbie Opatz** and **Nate Jensen** identify the most cost-effective combination of resources for meeting customers' needs for reliable electric service during the next 15 years.

OTTER TAIL CORPORATION

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Email: sharesvc@ottertail.com
www.ottertail.com
NASDAQ: OTTR