Otter Tail Corp
Form 10-K
March 02, 2015

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

FORM 10-K
(Mark One)
Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2014

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 No)

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

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

Indicate by check mark whether the registrant has submitted electronically 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 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	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)

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 30, 2014 was $1,048,982,831.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 37,363,740 Common Shares ($5 par value) as of February 13, 2015.

Documents Incorporated by Reference:
Proxy Statement for the 2015 Annual Meeting-Portions incorporated by reference into Part III

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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.

ADP	Advance Determination of Prudence
Aevenia	Aevenia, Inc.
AFUDC	Allowance for Funds Used During Construction
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 740	ASC Topic 740 – Income Taxes
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
Aviva	Aviva Sports, Inc.
BART	Best-Available Retrofit Technology
Bemidji Project	Bemidji-Grand Rapids 230 kV Project
Brookings Project	Brookings-Southeast Twin Cities 345 kV Project
BTD	BTD Manufacturing, Inc.
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CapX2020	Capacity Expansion 2020
CASAC	Clean Air Scientific Advisory Council
Cascade	Cascade Investment L.L.C.
Cascade Note	$50 million 8.89% Senior Unsecured Note due November 30, 2017
CCMC	Coyote Creek Mining Company, L.L.C.
CO_2	Carbon Dioxide
CON	Certificate of Need
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction Work in Progress
CPP	Clean Power Plan
DENR	Department of Environment and Natural Resources
DMS	DMS Health Technologies, Inc.
ECR	Environmental Cost Recovery
EEI	Edison Electric Institute Index
EEP	Energy Efficiency Plan
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESSRP	Executive Survivor and Supplemental Retirement Plan
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
GHG	Greenhouse Gas
IMD	IMD, Inc.
IPH	Idaho Pacific Holdings, Inc.
IRP	Integrated Resource Plan
JPMorgan	JPMorgan Chase Bank, N.A.
JPMS	J.P. Morgan Securities
kV	kiloVolt
kW	kiloWatt
kwh	kilowatt-hour
LSA	Lignite Sales Agreement
MAPP	Mid-Continent Area Power Pool

MATS	Mercury and Air Toxics Standards
MDU	MDU Resources Group, Inc.
MEI	Moorhead Electric, 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
MNRRA	Minnesota Renewable Resource Adjustment
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MRO	Midwest Reliability Organization
MVP	Multi-Value Project
MW	megawatts
mwh	megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NAEMA	North American Energy Marketers Association
NDDOH	North Dakota Department of Health
NDPSC	North Dakota Public Service Commission
NDRRA	North Dakota Renewable Resource Adjustment
NICF	Notice of Intent to Construct Facilities
NPCA	National Parks Conservation Association
NPDES	National Pollutant Discharge Elimination System
Northern Pipe	Northern Pipe Products, Inc.
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
OTESCO	Otter Tail Energy Services Company
OTP	Otter Tail Power Company
PCOR	Plains CO_2 Reduction Partnership
PEM	Power and Energy Market
PM2.5	Particulate Matter Less Than 2.5 Microns
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PVC	Polyvinyl Chloride
RCRA	Resource Conservation and Recovery Act
RPEC	Retirement Plans Experience Committee
RTO	Regional Transmission Organization
RTO Adder	Incentive of additional 50-basis points for RTO participation
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
SF6	Sulfur Hexaflouride
Shrco	Shrco, Inc.
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
T.O. Plastics	T.O. Plastics, Inc.
TCR	Transmission Cost Recovery

Trinity	Trinity Industries, Inc.
Varistar	Varistar Corporation
VIC	Voluntary Investigation and Cleanup
VIE	Variable Interest Entity
Vinyltech	Vinyltech Corporation
Wylie	E.W. Wylie Corporation

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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 1,893 full-time employees in its continuing operations at December 31, 2014. 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.

Over the last four years, 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. In 2011, the Company sold Idaho Pacific Holdings, Inc. (IPH), its Food Ingredient Processing business, and E.W. Wylie Corporation (Wylie), its trucking company, which was included in its former Wind Energy segment. In January 2012, the Company sold the assets of Aviva Sports, Inc. (Aviva), a recreational equipment manufacturer and a wholly owned subsidiary of Shrco, Inc. (Shrco), the Company’s former waterfront equipment manufacturer. In February 2012, the Company sold DMS Health Technologies, Inc. (DMS), its former Health Services segment business. In November 2012, the Company completed the sale of the assets of IMD, Inc. (IMD), the Company’s former wind tower manufacturer, and exited the wind tower manufacturing business. On February 8, 2013 the Company sold substantially all the assets of Shrco. As of December 31, 2014 the Company was in the process of negotiating sales of Foley Company (Foley) and Aevenia, Inc. (Aevenia), its Construction segment subsidiaries and had entered into letters of intent with the buyers with expected closings during the first quarter of 2015.

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

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is an active wholesale participant in the Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907. Additionally, the electric segment includes Otter Tail Energy Services Company (OTESCO), which provided technical and engineering services through December 31, 2012. OTESCO ceased operations and did not record any operating revenues, expenses or net income in 2013 or 2014.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping and fabrication, and production of material and handling trays, horticultural containers and produce packaging. These businesses have manufacturing facilities in 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 nonelectric 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 2013 non-GAAP earnings 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 already in place at the Company's manufacturing and plastic pipe businesses, as well as the facilities expansion and addition of paint services at BTD Manufacturing, Inc. (BTD), which will occur during 2015 and 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 segment. 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 2014 was 77% from the electric utility and 23% from the manufacturing and plastic pipe businesses, including unallocated corporate costs.

In evaluating its portfolio of operating companies, the Company looks for the following characteristics:

A threshold level of net earnings and a return on invested capital in excess of the Company's weighted average cost of capital.

A strategic differentiation from competitors and a sustainable cost advantage.

A stable or growing industry.

An ability to quickly adapt to changing economic cycles.

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 36 through 60 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 79 through 81 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. Prior to December 31, 2012 Electric also included the operations of OTESCO, which provided technical and engineering services primarily in North Dakota and Minnesota that were not materially significant in 2012. The Company derived 51%, 50% and 49% of its consolidated operating revenues and 76%, 66% and 65% of its consolidated operating income from the Electric segment for the years ended December 31, 2014, 2013 and 2012, respectively.

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

State	2014	2013
Minnesota	49.5 %	48.2 %
North Dakota	41.6	42.8
South Dakota	8.9	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 125,646 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, 2014, OTP served 130,490 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	2014	2013
Commercial	37.3 %	36.9 %
Residential	32.3	33.3
Industrial	25.3	23.2
All Other Sources	5.1	6.6
Total	100.0%	100.0%

Wholesale electric energy kilowatt-hour (kwh) sales were 5.8% of total kwh sales for 2014 and 12.5% for 2013. Wholesale electric energy kwh sales decreased by 54.8% between the years while revenue per kwh sold increased by 98.1%. Activity in the short-term energy market is subject to change based on a number of factors and it is difficult to predict the quantity of wholesale power sales or prices for wholesale power in the future.

Capacity and Demand

As of December 31, 2014 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants		
Big Stone Plant	257,600	kW
Coyote Station	150,200	
Hoot Lake Plant	148,600	
Total Baseload Net Plant	556,400	kW
Combustion Turbine and Small Diesel Units	107,800	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 2014, about 67% 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, 2014:

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)		
Purchase: Great River Energy[1]	100,000	kW

[1]100,000 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 2014. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2015 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 2014 and 2013:

Sources	2014 Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated		2013 Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated	
Subbituminous Coal	2,011,002	57.3	%	2,322,608	62.4	%
Lignite Coal	933,036	26.6		881,973	23.7	
Wind and Hydro	523,280	14.9		471,176	12.7	
Natural Gas and Oil	44,105	1.2		43,165	1.2	
Total	3,511,423	100.0	%	3,718,922	100.0	%

OTP has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Peabody COALSALES, LLC	Wyoming subbituminous	December 31, 2017
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	May 4, 2016
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, 2015

OTP has about 87% of its coal needs for Big Stone under contract through December 2017.

The contract with Dakota Westmoreland Corporation expires on May 4, 2016. 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 to be paid by the Coyote Station owners under the LSA will reflect 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 has about 84% of its anticipated coal needs for Hoot Lake Plant secured under contract through December 2015.

It is OTP's practice to maintain a minimum 30-day inventory (at full output) of coal at the Big Stone Plant and a 20-day inventory at Coyote Station and Hoot Lake Plant.

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 for the years 2014, 2013, and 2012 was $2.036, $2.055, and $2.108, 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:

		2014		2013	
Rates	Regulation	% of Electric Revenues	% of kwh Sales	% of Electric Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	44.9 %	46.8 %	43.8 %	42.5 %
ND Retail Sales	ND Public Service Commission	37.8	38.8	39.0	36.8
SD Retail Sales	SD Public Utilities Commission	8.1	8.6	8.2	8.2
Transmission & Wholesale	Federal Energy Regulatory Commission	9.2	5.8	9.0	12.5
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 that 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 Project—This is a planned 345 kiloVolt (kV) transmission line that will extend approximately 70 miles between a proposed substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Xcel Energy jointly developed this 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 that the costs of transmission projects with regional benefits are properly assigned to those who benefit. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. The SDPUC approved the certification for the northern portion of the route on April 9, 2013 and granted approval of a route permit for the southern portion of the line on February 18, 2014. On August 1, 2014 OTP and Xcel Energy entered into agreements to construct the project. This line is expected to be in service in 2017. OTP's total capital investment in this project is expected to be approximately $99 million.

The Big Stone South – Ellendale Project—This is a proposed 345 kV transmission line that will extend 160 to 170 miles between a proposed substation near Big Stone City, South Dakota and a proposed substation near Ellendale, North Dakota. OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. On August 25, 2013 the NDPSC granted Certificates of Public Convenience and Necessity to OTP and MDU for ten miles of the proposed line to be built in North Dakota. On July 10, 2014 the NDPSC approved a Certificate of Corridor Compatibility and a route permit for the North Dakota section of the proposed line. On August 22, 2014 the SDPUC issued an order approving the route permit for the South Dakota section of the proposed line. If the proposed project receives all the necessary approvals, OTP anticipates the line will be completed in 2019. OTP's total capital investment in this project is expected to be approximately $159 million.

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. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo–Monticello 345 kV Project (the Fargo Project), (2) the Brookings–Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji–Grand Rapids 230 kV Project (the Bemidji Project), and (4) the Twin Cities–LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project. Recovery of OTP's CapX2020 transmission investments is through the MISO Tariff (the Brookings Project as an MVP) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

The Fargo Project—The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. The St. Cloud to Alexandria portion of the Fargo Project was placed into service on April 23, 2014. Construction is underway for the remaining portion of the project, which is expected to be in service in 2015. OTP's share of the costs for the St. Cloud to Fargo portion of the Fargo Project is expected to be $83 million.

The Brookings Project—The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. The first phase of the 250 mile Brookings Project was energized in March 2014. Additional segments of the line were energized in April 2014. The entire project is expected to be in service in 2015. OTP's share of the costs for the Brookings Project is expected to be $26 million.

The Bemidji Project—The Bemidji-Grand Rapids transmission line was fully energized and put into service on September 17, 2012.

Big Stone Plant Air Quality Control System (AQCS)—The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to Best-Available Retrofit Technology (BART) requirements of the Clean Air Act (CAA), based on air dispersion modeling indicating that Big Stone Plant's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan.

OTP is currently in the process of constructing the BART-compliant AQCS at Big Stone Plant for a current projected cost of approximately $384 million (OTP's 53.9% share would be $207 million) with an expected commercial operation date of October 2015. OTP's share of AQCS construction expenditures incurred through December 31, 2014 is $153 million, excluding Allowance for Funds Used During Construction (AFUDC).

Big Stone II Project—On June 30, 2005 OTP and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project's lead developer—from Big Stone II. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project. OTP requested jurisdictional recovery in Minnesota, North Dakota and South Dakota of amounts it had invested in the Big Stone II project at the time of its withdrawal, discussed below under the respective jurisdictional sections of this report.

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.

2010 General Rate Case—OTP's most recent 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. The MPUC's written order included: (1) recovery of Big Stone II costs over five years, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment. 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.

In the MPUC order approving the 2011-2025 IRP in February 2012, OTP was required to submit a base-load diversification study specifically focused on evaluating retirement and repower options for the Hoot Lake Plant. In an order dated March 25, 2013 the MPUC approved OTP's recommendations that Hoot Lake Plant add pollution-control equipment at a cost of approximately $10.0 million to comply with U.S. Environmental Protection Agency's (EPA) mercury and air toxics standards by 2015 and discontinue burning coal by May 31, 2021.

On December 2, 2013 OTP filed its 2014-2028 IRP with the MPUC. Copies of the 2014-2028 IRP were provided to both the NDPSC and SDPUC. 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 megawatts (MW) of wind between 2017 and 2021 if it is cost effective and does not negatively impact OTP's electric system operation.

The ordered construction of solar generation to comply with the Minnesota Solar Energy Standard by 2019 to be operational when the standard takes effect in 2020.

Confirmation of a 1.5% energy savings goal, as filed in OTP's triennial MNCIP plan.

Authorization to obtain 200 MW of intermediate natural gas generation in the 2019-2021 timeframe.

OTP's 2016-2030 IRP is due to be filed December 1, 2015.

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 carbon dioxide (CO_2) regulation to be used in modeling analyses for resource plans is \$9 to \$34/ton of CO_2 commencing in 2019. 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. OTP is currently evaluating potential options for meeting that standard. 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 comply with Minnesota renewable energy standards. 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.

The costs for three major wind farms previously approved by the MPUC for recovery through OTP's Minnesota Renewable Resource Adjustment (MNRRA) were moved to base rates as of October 1, 2011 under the MPUC's April 25, 2011 general rate case order with the exception of the remaining balance of the MNRRA regulatory asset. OTP continued to collect the remaining regulatory asset balance through April 30, 2013, when the balance was near zero. On April 4, 2013 the MPUC authorized that any remaining unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case. Effective May 1, 2013 the resource adjustment on OTP's Minnesota customers' bills no longer includes MNRRA costs.

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 January 11, 2012 the MPUC approved the recovery of $3.5 million for 2010 MNCIP financial incentives. Beginning in January 2012, OTP’s MNCIP Conservation Cost Recovery Adjustment increased from 3.0% to 3.8% for all Minnesota retail electric customers. On March 30, 2012 OTP recognized an additional $0.4 million of incentive related to 2011 and submitted its annual 2011 financial incentive filing request for $2.6 million. In December 2012, the MPUC approved the recovery of $2.6 million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer’s bill to an amount per kwh consumed. On January 1, 2013 OTP’s MNCIP surcharge decreased from 3.8% of the customer’s bill to $0.00142 per kwh, which equates to approximately 1.9% of a customer’s bill.

OTP recognized $2.6 million of MNCIP financial incentives in 2012 and an additional $0.1 million in 2013 relating to 2012 program results. On October 10, 2013 the MPUC approved OTP’s 2012 financial incentive request for $2.7 million as well as its request for an updated surcharge rate to be implemented on November 1, 2013. OTP recognized $3.9 million in MNCIP financial incentives in 2013 related to the results of its conservation improvement programs in Minnesota in 2013. On April 1, 2014 OTP submitted its annual 2013 financial incentive filing request for $4.0 million along with a request for an updated surcharge rate. 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. Based on preliminary results from the 2014 MNCIP program year, OTP is estimating a financial incentive for 2014 of $2.5 million. OTP is estimating a lower incentive for 2014 in response 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. Also, OTP estimates it saved approximately 3 million less kwhs in 2014 compared with 2013. OTP will request approval from the MNPUC in an April 1, 2015 filing.

<u>Transmission Cost Recovery Rider</u>—In addition to the MNRRA rider, the Minnesota Public Utilities Act (the Act) provides a similar 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 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. 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. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers. On March 26, 2012 the MPUC approved an update to OTP's Minnesota TCR rider along with an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made in transmission facilities that qualify for regional cost allocation under the MISO Tariff, with an offsetting credit for revenues received from other MISO utilities under the MISO Tariff for projects included in the TCR. OTP's updated Minnesota TCR rider went into effect April 1, 2012.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On February 20, 2013 the MPUC approved three of the additional projects as eligible for recovery through the TCR rider. OTP filed its annual update to the TCR rider on February 7, 2013 to include the 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 disallowed recovery of capitalized internal costs, costs in excess of CON estimates and a carrying charge in the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP will be allowed to seek recovery of these costs in a future rate case. In response to the MPUC 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. OTP filed its 2014 annual update on May 1, 2014. The MNDOC recommended approval of the 2014 update on September 24, 2014. On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015.

Big Stone Plant AQCS—Minnesota law authorizes a public utility to petition the MPUC for an Advance Determination of Prudence (ADP) for a project undertaken to comply with federal or state air quality standards of states in which the utility's electric generation facilities are located if the project has an expected jurisdictional cost to Minnesota ratepayers of at least $10 million. On January 14, 2011 OTP filed a petition asking the MPUC for ADP for costs associated with the design, construction and operation of the BART compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers. The MPUC granted OTP's petition for ADP for the AQCS in a written order issued on January 23, 2012.

Environmental Cost Recovery (ECR) Rider—On May 24, 2013 legislation was enacted in Minnesota which allowed OTP to file an emission-reduction rider for recovery of the revenue requirements of the AQCS. The legislation authorizes the rider to allow a current return on investment, including Construction Work in Progress (CWIP), at the level approved in OTP's most recent general rate case, unless a different return is determined by the MPUC to be in the public interest. 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 include a current return on the project's CWIP balance at the level approved in OTP's most recent general rate case. OTP filed its 2014 annual update on July 31, 2014, requesting a $4.1 million annual increase in the rider from $6.1 million to $10.2 million. The MPUC approved OTP's ECR rider annual update request on November 24, 2014, effective December 1, 2014. Because the effective date was two months behind the anticipated implementation date for the updated rate and a portion of the requested increase had been collected under the initial rate, the approved updated rate is based on a revenue requirement of $9.8 million. The rate will continue to be updated in annual filings with the MPUC until the costs are rolled into base rates at an undetermined future date.

Big Stone II Project Cost Recovery—OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period which began on October 1, 2011. The amount of Big Stone II generation costs incurred by OTP that were deemed recoverable from Minnesota ratepayers as part of the rates established in that proceeding was $3.2 million. Because OTP was not allowed to earn a return on these deferred costs over the 60-month recovery period, the recoverable amount of $3.2 million was discounted to its present value of $2.8 million using OTP's incremental borrowing rate, in accordance with Accounting Standards Codification (ASC) Topic 980, Regulated Operations (ASC 980) accounting requirements. Transmission-related project costs of $3.2 million remained in CWIP as active project costs at the time of the order.

Approximately $0.4 million of the total Minnesota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP transmission line project in the first quarter of 2013. The remaining transmission costs, along with accumulated AFUDC, were transferred from CWIP to a regulatory asset account in May 2013, based on recovery granted in the April 25, 2011 order. Because OTP was not allowed to earn a return on these deferred costs over their anticipated recovery period, the recoverable amount of approximately $3.5 million was discounted to its present value using OTP's incremental borrowing rate. In May 2013, OTP recorded a charge of $0.7 million related to the discount in accordance with ASC 980 accounting requirements. In June 2014, OTP recorded an additional discount of $0.3 million to reflect changes in the end date of the anticipated recovery period from September 2020 to December 2022.

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 1, 2014, which is in effect until the MPUC issues a new capital structure order for 2015. OTP is required to file its 2015 capital structure petition no later than May 1, 2015.

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.

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. On March 21, 2012 the NDPSC approved an update to OTP's NDRRA effective April 1, 2012. The updated NDRRA recovered $9.9 million over the period April 1, 2012 through March 31, 2013. On December 28, 2012 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2013. The update resulted in a rate reduction, so the NDPSC did not issue an order suspending the rate change. Consequently, pursuant to statute, OTP was allowed to implement updated rates effective April 1, 2013. On July 10, 2013, the NDPSC approved the updated rates implemented on April 1, 2013. The NDPSC approved OTP's most recent annual update to the NDRRA on March 12, 2014 with an effective date of April 1, 2014. The update approved on March 12, 2014 resulted in a 13.5% reduction in the NDRRA rate. On December 31, 2014 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2015.

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. On April 29, 2011 OTP filed a request for an initial North Dakota TCR rider with the NDPSC, which was approved on April 25, 2012 and effective May 1, 2012. On August 31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider. The NDPSC approved the annual update on December 12, 2012 with an effective date of January 1, 2013. On August 30, 2013 OTP filed its annual update to its North Dakota TCR rider rate, which was approved on December 30, 2013 and became effective January 1, 2014. On August 29, 2014 OTP filed its annual update to the North Dakota TCR rider rate. Within this TCR filing, as required by the order for the North Dakota Big Stone II rider, OTP included the over-collection of North Dakota Big Stone II abandoned plant costs of $0.1 million. The NDPSC approved the annual update on December 17, 2014 with an effective date of January 1, 2015.

Environmental Cost Recovery Rider—On May 9, 2012 the NDPSC approved OTP's application for an ADP related to the Big Stone Plant AQCS. On February 8, 2013 OTP filed a request with the NDPSC 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. On December 18, 2013 the NDPSC approved OTP's North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on or after January 1, 2014. On March 31, 2014 OTP filed its 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. On July 10, 2014 the NDPSC approved OTP's 2014 ECR rider annual update request with an August 1, 2014 implementation date.

Big Stone II Project—On August 27, 2008, the NDPSC determined that OTP's participation in Big Stone II was prudent in a range of 121.8 to 130 MW. On January 20, 2010, OTP filed a request with the NDPSC for a determination that continuing with the Big Stone II project would not have been prudent.

In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC advocacy staff, OTP and the North Dakota Large Industrial Energy Group, Interveners. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excluded $2.6 million of project transmission-related costs) was determined to be $10.1 million, of which $4.1 million represents North Dakota's jurisdictional share.

OTP included in its total recovery amount a carrying charge of approximately $0.3 million on the North Dakota share of Big Stone II generation costs for the period from September 1, 2009 through the date the recovery of costs began based on OTP's average 2009 AFUDC rate of 7.65%. Because OTP would not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of $4.3 million was discounted to its then present value of $3.9 million using OTP's incremental borrowing rate, in accordance with ASC 980 accounting requirements. The North Dakota portion of Big Stone II generation costs was recovered over a 36-month period which began on August 1, 2010.

The North Dakota jurisdictional share of Big Stone II costs incurred by OTP related to transmission was $1.1 million. Approximately $0.3 million of the total North Dakota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP during the first quarter of 2013. On July 30, 2013 the NDPSC approved OTP's request to continue the Big Stone II cost recovery rates for an additional eight months through March 31, 2014 to recover the remaining North Dakota share of Big Stone II transmission-related costs plus accrued AFUDC totaling $1.0 million. As of April 1, 2014 North Dakota customer's bills no longer include a charge for the North Dakota share of Big Stone II costs. OTP had a regulatory liability of $0.1 million as of December 31, 2014 for amounts billed to North Dakota customers that will be refunded through the North Dakota TCR rider.

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—On April 21, 2011, the SDPUC issued a written order approving an overall revenue increase for OTP of approximately $643,000 (2.32%) and an overall rate of return on rate base of 8.50%. Final rates were effective with bills rendered on and after June 1, 2011.

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. OTP submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. The SDPUC approved an annual update to OTP's South Dakota TCR on April 23, 2013 with an effective date of May 1, 2013. The SDPUC approved OTP's following annual update to its South Dakota TCR on February 18, 2014 with an effective date of March 1, 2014. OTP filed another annual update on October 31, 2014, which was approved by the SDPUC on February 13, 2015 with an effective date of March 1, 2015.

Environmental Cost Recovery Rider—On March 30, 2012 OTP requested approval from the SDPUC for an ECR rider to recover costs associated with the Big Stone Plant AQCS. On April 17, 2013 OTP filed a request to either suspend or withdraw this filing. The SDPUC approved withdrawing this filing on April 23, 2013. On August 29, 2014 OTP filed a new request with the SDPUC for an ECR rider to recover costs associated with new environmental measures including costs to comply with mercury and air toxics standards. On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover the costs of the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) projects, with an effective date of December 1, 2014.

Big Stone II Project—OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately $1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP is allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted. OTP transferred the South Dakota portion of the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP.

A portion of the Big Stone II transmission costs were transferred out of CWIP in February 2013 to be included within the Big Stone South - Brookings MVP. On March 28, 2013, OTP filed a petition with the SDPUC requesting deferred accounting for the remaining unrecovered Big Stone II Transmission costs until OTP's next South Dakota general rate case. The petition was approved by the SDPUC on April 23, 2013 and in May 2013 OTP transferred the remaining South Dakota jurisdictional portion of unrecovered Big Stone II transmission costs plus accumulated AFUDC totaling $0.2 million from CWIP to the Big Stone II Unrecovered Project Costs – South Dakota regulatory asset accounts.

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 25, 2011 OTP filed a request with the SDPUC for approval of updates to its EEP. The SDPUC approved the 2012 2013 updated EEP with a maximum available incentive payment limited to 30% of the budget amount provided in the EEP, or $84,000. On June 19, 2012, the SDPUC approved OTP's request for a 2011 financial incentive of $78,900 along with an increased surcharge adjustment that became effective on July 1, 2012. On June 18, 2013 the SDPUC approved OTP's request for a 2012 financial incentive of $84,000 along with an increased surcharge adjustment that became effective July 1, 2013. On November 5, 2013, the SDPUC approved OTP's EEP updates for 2014-2015. On December 3, 2013, the SDPUC voted to amend the approval previously given and require OTP to come before the Commission if the overall plan budget would exceed 10%, rather than the previously approved 30%.

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.

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.

Effective January 1, 2010 the FERC authorized OTP's implementation of a forward looking formula transmission rate under the MISO Tariff. OTP was also authorized by the FERC to recover in its formula rate (1) 100% of prudently incurred CWIP in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP’s control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects in which OTP is a joint owner: the Fargo Project, the Bemidji Project and the Brookings Project.

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.

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. On June 7, 2013, in response to a challenge to the MVP cost allocation heard before the United States Court of Appeals, Seventh Circuit, the Court ruled in favor of MISO and MISO transmission owners, issuing an order affirming the FERC’s approval of the MVP cost allocation. On February 24, 2014 the U.S. Supreme Court denied petitions for a writ of certiorari of the Seventh Circuit’s decision upholding the FERC’s MVP orders. The petitioners did not seek rehearing.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the current 12.38% return on equity used in MISO’s transmission rates to a proposed 9.15%. A group of MISO transmission owners have filed responses to the complaint, defending the current return on equity and seeking dismissal of the complaint. On October 16, 2014 the FERC issued an order finding that the current MISO return on equity may be unjust and unreasonable and setting the issue for hearing, subject to the outcome of settlement discussion. Settlement discussions did not resolve the dispute and the FERC set the proceeding to a Track II Hearing for complex cases that can take several months to decide, with a FERC decision anticipated in fall 2016 at the earliest. 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 (RTO) participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the resolution of the return on equity complaint proceeding.

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. NAEMA was formed as a successor organization of the Power and Energy Market (PEM) of the Mid-Continent Area Power Pool (MAPP) in recognition that PEM had outgrown the MAPP region. Power pool sales are conducted continuously through NAEMA in accordance with schedules filed by NAEMA with the FERC.

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 North American

Electric Reliability Corporation. 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. MRO assumed the reliability functions of the MAPP and Mid-America Interconnected Network, both former voluntary regional reliability councils.

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 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, 2014 OTP invested approximately $189 million in environmental control facilities. The 2015 and 2016 construction budgets include approximately $56 million and $3 million, respectively, for environmental equipment for existing facilities.

Air Quality - Criteria Pollutants—Pursuant to the 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. Hoot Lake Plant Unit 1, which is the smallest of the three coal-fired units at Hoot Lake Plant, was retired as of December 31, 2005. The Hoot Lake Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The South Dakota 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 other 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 2014.

The EPA Administrator signed the Clean Air Interstate Rule (CAIR) on March 10, 2005. The EPA has concluded that SO_2 and NO_x are the chief emissions contributing to interstate transport of particulate matter less than 2.5 microns (PM2.5). The EPA also concluded that NO_x emissions are the chief emissions contributing to ozone nonattainment. Twenty-three states and the District of Columbia were found to contribute to ambient air quality PM2.5 nonattainment in downwind states. On that basis, the EPA proposed to cap SO_2 and NO_x emissions in the designated states. Minnesota was included among the twenty three states subject to emissions caps; North Dakota and South Dakota were not included. Twenty-five states were found to contribute to downwind 8-hour ozone nonattainment. None of the states in OTP's service territory were slated for NO_x reduction for 8-hour ozone nonattainment purposes. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAIR and the CAIR federal implementation plan in its entirety.

On December 23, 2008 the court reconsidered its order vacating CAIR, instead remanding the rule to the EPA to conduct further proceedings consistent with the court's prior opinion invalidating CAIR. On January 16, 2009 the EPA proposed a rule that would stay the effectiveness of CAIR and the CAIR federal implementation plan for sources in Minnesota while the EPA conducted notice-and-comment rulemaking on remand from the D.C. Circuit's decisions in the litigation on CAIR. Remanding the issue to the EPA for further consideration, the court held that the EPA had not adequately addressed errors alleged by Minnesota Power in the EPA's analysis supporting inclusion of Minnesota. Neither the EPA nor any other party sought rehearing of this part of the court's CAIR decision. Public Notice of the final rule staying the implementation of CAIR in Minnesota appeared in the November 3, 2009 Federal Register.

On July 8, 2011 the EPA released a final rule termed the Cross-State Air Pollution Rule (CSAPR) that essentially would replace the CAIR, but which (unlike CAIR) included Minnesota sources due to a finding that Minnesota's emissions contribute to PM2.5 nonattainment in downwind states. A number of states and industry representatives challenged the rule. On December 30, 2011 the U.S. Court of Appeals for the D.C. Circuit granted motions to stay CSAPR pending the court's resolution of the petitions for review. The D.C. Circuit issued an order on August 21, 2012 vacating CSAPR. The order required the EPA to continue administering CAIR pending the promulgation of a valid replacement rule. The United States sought Supreme Court review of the D.C. Circuit's decision vacating CSAPR, and the Supreme Court granted review. On April 29, 2014 the U.S. Supreme Court issued its opinion, reversing the August 21, 2012 decision of the D.C. Circuit that had vacated CSAPR. CSAPR was remanded to the D.C. Circuit for further proceedings where, on July 26, 2014, the United States moved to lift the previously–entered stay. The EPA's motion asked the D.C. Circuit to implement CSAPR's Phase 1 emission budgets beginning January 1, 2015 for the annual SO_2 and NO_x programs. The D.C. Circuit granted the EPA's motion on October 23, 2014. On December 3, 2014 the EPA issued an interim final rule that tolls the original CSAPR deadlines by three years, such that the CSAPR program is scheduled to begin in 2015. However, the D.C. Circuit will be hearing oral argument on the remand proceedings during the first half of 2015 that could ultimately impact OTP's compliance obligations.

The CSAPR rule is expected to apply to OTP's Solway gas peaking plant and the Hoot Lake coal-fired plant in Minnesota. The primary anticipated impact of the rule for Hoot Lake Plant is to require SO_2 allowances to continue operating at historical levels. Based on Hoot Lake's historical generation and early market pricing, CSAPR could result in annual SO_2 allowance purchase costs of approximately $1.0 million. The specific annual cost impact of purchasing allowances is unknown since the market is not well established. Minnesota is considered a Group 2 state for SO_2 compliance along with Alabama, Georgia, Kansas, Nebraska, South Carolina and Texas. 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.

Since 2008, the primary and secondary national ambient air quality standards (NAAQS) for ozone have been set at 0.075 parts per million (ppm). The primary standard, which is designed to protect public health with an adequate margin of safety, was upheld as reasonable by the D.C. Circuit in 2013. The court remanded the secondary standard, which is designed to protect welfare interests such as agricultural and visibility interests, on the ground that the EPA had not adequately explained its decision to set the secondary standard at the same level as the primary. On December 17, 2014, the EPA published a proposed rule indicating the Agency's intent to issue more stringent primary and secondary ozone standards of between 0.065

and 0.070 ppm. The Agency is also taking comment on the possibility of issuing a standard as low as 0.060 ppm or retaining the current 0.075 ppm standard. The range proposed by the EPA is consistent with the recommendations of the Clean Air Scientific Advisory Council (CASAC), whose recommendations the EPA is required to consider in setting NAAQS. The EPA may depart from CASAC's recommendations, but only if it adequately explains its reasons for departure. CASAC has recommended that the primary NAAQS be set between 0.060 and 0.070 ppm. The EPA is taking comment on the proposal until March 17, 2015, and is expected to finalize the NAAQS by the summer of 2015. If the EPA sets the NAAQS at 0.065 ppm or below, it would throw at least a portion of southeastern South Dakota into non-attainment of that standard, with attendant additional pollution reduction requirements that could impact OTP. Litigation over any final standard is certain, and uncertainty over it will therefore continue for some time.

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 will have until April 16, 2015 to comply. However, the EPA is encouraging state permitting authorities to broadly grant a one-year compliance extension to plants that need additional time to install controls. The DENR granted Big Stone Plant a one-year compliance extension in August 2013. The EPA is also providing a pathway for reliability-critical units to obtain an additional year to achieve compliance; however, the EPA has indicated that it believes there will be few, if any situations, in which this pathway is needed. OTP's affected units will meet the requirements by installing the AQCS system at Big Stone, by upgrading the electrostatic precipitators on Hoot Lake Units 2 and 3, by installing activated carbon injection on all units, and by possibly installing dry sorbent injection at Hoot Lake Plant. Emissions monitoring equipment and/or stack testing will also be needed to verify compliance with the standards. Numerous petitions were filed in the United States Court of Appeals for the D.C. Circuit challenging the MATS rule. On April 15, 2014 the Court denied all petitions for review. Certain parties filed petitions for certiorari with the U.S. Supreme Court. On November 25, 2014 the U.S. Supreme Court granted certiorari limited to the single question of whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. A decision is expected in mid-2015. Because no stay of the rule was obtained, MATS continues to govern pending resolution of the judicial challenges to the rule.

Air Quality – EPA New Source Review Enforcement Initiative—In 1998 the EPA announced its New Source Review Enforcement Initiative targeting coal-fired utilities, 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. The EPA is attempting 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. On January 2, 2001 OTP received a request from the EPA, pursuant to Section 114(a) of the CAA, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. OTP responded to that request. In March 2003 the EPA conducted a review of the plant's outage records as a follow-up to its January 2001 data request. A copy of the designated documents was provided to the EPA on March 21, 2003.

On January 8, 2009, OTP received another request from EPA Regions 5 and 8, pursuant to Section 114(a) of the CAA, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant, Coyote Station and Hoot Lake Plant. OTP filed timely responses to the EPA's requests on February 23, 2009 and March 31, 2009. In July 2009, EPA Region 5 issued a follow-up information request with respect to certain maintenance and repair work at the Hoot Lake Plant. OTP responded to the request. The EPA has not set forth any additional follow-up requests at this time. OTP cannot determine what, if any, actions will be taken by the EPA.

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 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 must 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. Big Stone Plant must install and operate the BART compliant air quality control system as expeditiously as practicable, but not later than five years after the EPA's final approval of May 29, 2012. The current project cost is estimated to be approximately $384 million (OTP's share would be $207 million).

The North Dakota Regional Haze SIP requires that Coyote Station reduce its NO_x emissions. On March 14, 2011 the North Dakota Department of Health (NDDOH) issued a construction permit to Coyote Station requiring installation of control equipment to limit 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 current estimate of the total cost of the project is $9 million ($3.2 million for OTP's share). On March 1, 2012 the EPA signed a final rule for partial approval of the North Dakota SIP that included the NO_x emission rate permit conditions for Coyote Station as proposed by the NDDOH. The rule became effective on May 7, 2012.

In June 2012 the Sierra Club and National Parks Conservation Association (NPCA) filed an appeal of the EPA's approval of the North Dakota Regional Haze SIP to the U.S. Court of Appeals for the Eight Circuit that included a challenge to the EPA's determinations relative to several North Dakota plants, including Coyote Station. On September 23, 2013 the Eighth Circuit denied the Sierra Club/NPCA appeal with respect to Coyote Station.

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 656 MW. In 2014 these plants emitted approximately 3.6 million tons of CO_2.

OTP monitors and evaluates the possible adoption of national, regional, or state climate change and GHG legislation or regulations that would affect electric utilities. Congress previously 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, is uncertain.

In April 2007, however, 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 Supreme Court directed the EPA to conduct 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; according to the EPA, 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 findings did not in and of themselves impose any emission reduction requirements but rather allowed 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 apply to motor vehicles as of January 2011, which makes 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 phases 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 depending on what activities take place at a major source. If triggered, the owner or operator of an affected facility must undergo a review which requires the identification and implementation of best-available control technology 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 treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. However, the U.S. Supreme Court also said the EPA could continue to require PSD permits, otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of best-available control technology. OTP does not anticipate making modifications that would trigger PSD requirements at any of its facilities.

The EPA is developing New Source Performance Standards (NSPS) for GHGs from fossil fuel-fired electric generating units. The EPA proposed a rule on January 8, 2014 that would subject large new coal-fired units to a GHG emission limit of 1,100 lbs. of CO_2 per megawatt-hour (mwh) averaged over a 12-month period, or possibly a limit of 1,000 1,050 pounds of CO_2 averaged over a period of seven years. This limit is based on emission reductions the EPA believes could be achieved through the installation and operation of partial carbon capture and sequestration technology. Certain new natural gas-fired units would be subject to a limit of 1,000 or 1,100 pounds of CO_2 per mwh, dependent on unit size, which is the emissions level the EPA believes natural gas combined cycle units can currently achieve with no additional add-ons. Unlike traditional NSPS rules, the proposed GHG NSPS would not apply to modifications at existing units. If finalized, the NSPS would apply to any unit that commences construction after the date of the proposal, or January 8, 2014.

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The EPA also is developing GHG performance standards for existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike a NSPS, 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 proposes 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 must be achieved on average over the ten year period of 2020-2029, and a final goal must be achieved in 2030 and each year thereafter. The EPA uses 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 formula creates substantially different targets for North Dakota, South Dakota, and Minnesota, primarily due to the EPA's second building block that envisions redispatching natural gas combined cycle units to a 70% capacity factor.

At the same time as the existing source guidelines were published, the EPA published separate CO_2 emission standards for reconstructed and modified fossil fuel-fired power plants essentially requiring that such plants install modern technology, when modifying or reconstructing, to reduce their emissions. The EPA plans to issue final rules for new, modified or reconstructed, and existing power plants sometime during summer 2015. For existing sources, states would then be required to develop and submit plans, either individually or with other states, spelling out how they will achieve the individualized, reduced CO_2 emission rates that the EPA has identified. Those state plans would be due in summer 2016. The EPA is proposing to allow, upon reasonable request, one-year extensions for states proposing individual plans and two-year extensions for states proposing to submit multi-state plans. At the same time as issuing the CPP, the EPA also announced plans to propose a federal plan for public review and comment. In summer 2016, the EPA plans to be in a position to issue a final federal plan for meeting CPP goals in states that do not submit plans.

OTP is actively participating with other stakeholders in efforts to shape the final performance standards for new, modified and reconstructed, and existing power plants both at the federal level and, where applicable, at the state level. OTP submitted extensive comments on the CPP to the EPA on November 25, 2014. It is not possible to determine, at this time, the potential impact to OTP of these future regulations on new, modified or reconstructed, or existing sources. Litigation relating to all of these rules is already pending or is expected. Oral arguments before the D.C. Circuit on one set of preliminary challenges to the proposed Section 111(d) emission guidelines is now scheduled for April 2015, with a decision expected by summer 2015. Thus, uncertainty over whether the standards will be enforced or, if so, what will be permitted, may continue for a number of years.

Several states and regional organizations are also developing, or already have developed, 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 electricity 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. Regarding CO_2, 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. However, annual updates of the range are required. For 2014 the range is $9-$34/ton, and the start date to begin using CO_2 costs in resource planning decisions is 2019. 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 late in 2016.

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 proposed and pending climate change legislation and 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: OTP's efforts to increase plant efficiency and add renewable energy to its resource mix have reduced its CO_2 intensity. Between 1985 and 2014 OTP decreased its overall system average CO_2 emissions intensity by approximately 30%. Further reductions are expected with the anticipated replacement of Hoot Lake Plant generation likely with natural gas in the 2020 timeframe.

Conservation: Since 1992 OTP has helped its customers conserve nearly 57 MW of demand and nearly 2.8 million cumulative mwhs of electricity, which is roughly equivalent to the amount of electricity that 232,000 average homes would use in a year. OTP continues to educate customers about energy efficiency and demand-side management and to work with regulators to develop new programs. OTP's 2014-2028 IRP calls for an additional 106 MW of conservation and demand-side management impacts by 2028.

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.

Other: OTP is a participating member of the EPA's sulfur hexafluoride (SF6) Emission Reduction Partnership for Electric Power Systems program, which proactively is targeting a reduction in emissions of SF6, a potent GHG. SF6 has a global-warming potential 23,900 times that of CO_2. Methane has a global-warming potential over 20 times that of CO_2. OTP participates in carbon sequestration research through the Plains CO_2 Reduction Partnership (PCOR) 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.

In late 2009, two federal circuit courts of appeal reversed dismissals of GHG suits and remanded them to district court for trial. OTP was not a party to any of these suits, and does not have an indication that it will be the subject of such a lawsuit. The circuit court opinions, however, opened utility companies and other GHG emitters to these actions, which had previously been dismissed by the district courts as nonjustifiable based on the political question doctrine. In 2010, the U.S. Supreme Court took review of one of these cases, while declining review of another. On June 20, 2011, the Supreme Court ruled unanimously that states cannot invoke federal law to force utilities to cut GHG emissions, which was in agreement with the position of utilities and the EPA.

While the future financial impact of any proposed or pending climate change legislation, 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. The EPA announced its decision to proceed with further possible revisions to steam effluent guidelines on September 15, 2009, and published a proposed rulemaking on June 7, 2013. The proposed rulemaking primarily focuses on discharge restrictions applicable to fly ash transport water, bottom ash transport water, and flue gas desulfurization wastewater. Since the steam effluent guidelines rule is not final, at this time OTP is unable to determine how it will affect our facilities, but it appears that the rule could have minimal effect since the facilities do not discharge fly ash transport water, bottom ash transport water, or flue gas desulfurization wastewater into waters of the United States. A final rulemaking is anticipated by the end of 2015.

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 minimus" 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 already uses closed-cycle cooling.

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. 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 June 21, 2010 the EPA published a proposed rule that outlines two possible options to regulate disposal of coal ash generated from the combustion of coal by electric utilities under the Resource Conservation and Recovery Act (RCRA). In one option, the EPA would propose to list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth the EPA's hazardous waste regulatory program, which regulates the generation, handling, transport and disposal of wastes.

Under the second proposed regulatory option, the EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for nonhazardous solid wastes.

On December 19, 2014 the EPA announced a final rule following the Subtitle D nonhazardous provisions. 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. 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. The EPA is also considering future regulation of coal ash under Subtitle C. Publication of the final rule will open a 90-day window within which petitions for judicial review may be filed in the D.C. Circuit. Challenges by environmental groups are possible and the outcome of such challenges cannot be predicted. Thus, uncertainty regarding the status of this rule is likely to continue for some time.

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 provided a revised focus feasibility study for remediation alternatives to the MPCA in October 2004. OTP and the MPCA have reached an agreement identifying the remediation technology and OTP completed the projects in 2006. The effectiveness of the remediation is under ongoing evaluation. OTP completed an additional project in 2014 that removed the ash from one entire VIC area and placed it in OTP's permitted disposal area. OTP has notified the MPCA of a 2015 project that would focus on removing ash from another VIC area.

The EPA has promulgated various solid and hazardous waste regulations and guidelines pursuant to, among other laws, the Resource Conservation and Recovery Act of 1976, the Solid Waste Disposal Act Amendments of 1980 and the Hazardous and Solid Waste Amendments of 1984, which provide for, among other things, the comprehensive control of various solid and hazardous wastes from generation to final disposal. The states of Minnesota, North Dakota and South Dakota have also adopted rules and regulations pertaining to solid and hazardous waste. To date, OTP has incurred no significant costs as a result of these laws. The future total impact on OTP of the various solid and hazardous waste statutes and regulations enacted by the federal government or the states of Minnesota, North Dakota and South Dakota is not certain at this time.

In 1980, the United States enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly known as 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 2014, approximately $149 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2014 gross electric property additions, including construction work in progress, were approximately $521 million and gross retirements were approximately $60 million. OTP estimates that during the five-year period 2015-2019 it will invest approximately $665 million for electric construction, which includes $238 million for MVP transmission projects, $105 million for natural gas-fired generation to replace Hoot Lake Plant capacity and $53 million for the remainder of OTP's share of the Big Stone Plant AQCS. The remainder of the 2015-2019 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.

Franchises

At December 31, 2014 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, 2014 OTP had 663 equivalent full-time employees. A total of 401 OTP employees are represented by local unions of the International Brotherhood of Electrical Workers under two separate contracts expiring in the fall of 2016 and 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 and fabrication, and production of material handling trays and horticultural containers.

The Company derived 27%, 28% and 29% of its consolidated operating revenues and 17%, 22% and 22% of its consolidated operating income from the Manufacturing segment for the years ended December 31, 2014, 2013 and 2012, respectively. Following is a brief description of each of these businesses:

BTD Manufacturing, Inc., 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, lawn and garden, industrial equipment, health and fitness and enclosure industries in its facilities in Detroit Lakes and Lakeville, Minnesota, and Washington, Illinois. 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, and serves several major equipment manufacturers in the Peoria, Illinois area and nationwide, including Caterpillar, Komatsu and Gardner Denver.

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. In addition, T.O. Plastics produces products such as clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts for customers in the consumer products, food packaging, electronics, industrial and medical industries, among others. T.O. Plastics' Otsego thermoforming facility has an AIB International (formerly American Institute of Baking) 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 accounts 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.

Backlog

The Manufacturing segment has backlog in place to support 2015 revenues of approximately $140 million compared with $136 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 2014, cash expenditures for capital additions in the Manufacturing segment were approximately $11 million. Total capital expenditures for the Manufacturing segment during the five-year period 2015-2019 are estimated to be approximately $96 million.

Employees

At December 31, 2014 the Manufacturing segment had 1,031 full-time employees. There were 901 full-time employees at BTD and 130 full-time employees at T.O. Plastics.

PLASTICS

General

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The Company derived 22%, 22% and 21% of its consolidated operating revenues and 20%, 25% and 28% of its consolidated operating income from the Plastics segment for the years ended December 31, 2014, 2013 and 2012, 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 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.

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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 and western 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 areas of competition are a combination of price, service, warranty, and product performance. Northern Pipe and Vinyltech compete not only against other plastic pipe manufacturers, but also ductile iron, steel, concrete and clay pipe producers. Pricing pressure will continue to affect 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 mainly by common carrier.

The PVC resins are acquired in bulk and shipped to point of use by rail car. There are a limited number of third party vendors that supply the PVC resin used by Northern Pipe and Vinyltech. Two vendors provided approximately 98% and 93% of total resin purchases in 2014 and 2013, 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, land and buildings and management information systems. During 2014, cash expenditures for capital additions in the Plastics segment were approximately $4 million. Total capital expenditures for the five-year period 2015-2019 are estimated to be approximately $14 million to replace existing equipment.

Employees

At December 31, 2014 the Plastics segment had 151 full-time employees. Northern Pipe had 88 full-time employees and Vinyltech had 63 full-time employees as of December 31, 2014.

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.

A discretionary contribution of $10.0 million was made to our defined benefit pension plan in January 2015. 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 $31.5 million of goodwill recorded on our consolidated balance sheet as of December 31, 2014. We have recorded goodwill for businesses in each of our business segments except Electric. 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 any of our reporting units may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

In the fourth quarter of 2014 we entered into negotiations to sell our wholly owned subsidiary, Foley, a mechanical and prime contractor on industrial projects. As a result of an impairment indicator during the fourth quarter of 2014, we recorded a $5.6 million, or $0.15 per share, goodwill impairment charge. This impairment charge was based on the indicated offering price in a signed letter of intent for the purchase of Foley. The goodwill impairment loss is reflected in the results of discontinued operations and the remaining goodwill balance related to Foley is included in assets of discontinued operations. An assessment of the carrying amounts of the remaining goodwill of our reporting units reported under continuing operations as of December 31, 2014 indicated the fair values are substantially in excess of their respective book values and not impaired.

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 $150 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, 2014 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 45.0% and 55.0%. OTP’s equity-to-total-capitalization ratio was 49.8% as of December 31, 2014.

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. Our dividend payout ratio has exceeded our earnings (losses) in three of the last five years.

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 will have to 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 or loss of customers. 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.

Our plans to grow and operate our nonutility businesses could be limited by state law.

Our plans to grow and operate our manufacturing and plastic pipe businesses could be adversely affected by legislation in one or more states that may attempt to limit the amount or level of diversification permitted in a holding company structure that includes a regulated utility company or affiliated nonelectric companies.

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 remediation activities of 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 results of operations 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.

We are subject to risks and uncertainties related to the timing of recovery of deferred tax assets which could have a negative impact on our net income in future periods.

If taxable income is not generated in future periods in certain tax jurisdictions the recovery of deferred taxes related to accumulated tax benefits may be delayed and we may be required to record a reserve related to the uncertainty of the timing of recovery of deferred tax assets related to accumulated taxable losses in those tax jurisdictions. This would have a negative impact on the Company's net income in the period the reserve is recorded.

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.

Our electric utility company, OTP, owns electric transmission and generation facilities subject to mandatory and enforceable standards advanced by the North American Electric Reliability Corporation (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.

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.

A successful cyber-attack on the systems that control our generation, transmission, distribution or other assets could severely disrupt business operations, preventing us from serving customers or collecting revenues. 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 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.

OTP is subject to mandatory cybersecurity 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 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.

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. 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.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including OTP, may collect under the relevant MISO Tariff. On October 16, 2014 the FERC issued an order finding that the current MISO return on equity may be unjust and unreasonable and setting the issue for hearing, subject to the outcome of settlement discussion. Settlement discussions did not resolve the matters in dispute and the FERC set the proceeding to a Track II Hearing for complex cases that can take several months to decide, with a FERC decision anticipated in fall 2016 at the earliest. On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for RTO participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the resolution of the return on equity complaint proceeding. Depending on the outcome of hearing and the FERC's response, OTP may receive a lower return on equity on its MISO transmission rates and this may impact future revenues for transmission services provided in MISO.

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 on the direction and scope of U.S. 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.

The EPA has initiated action to regulate GHG emissions under its "endangerment" finding. 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 emission standards for reconstructed and modified fossil fuel-fired power plants, essentially requiring that such plants install modern technology, when modifying or reconstructing, to reduce their emissions. The EPA plans to issue final rules for each of these proposals in summer 2015. For existing sources, states would then be required to develop and submit plans, either individually or with other states, spelling out how they will achieve the individualized, reduced CO_2 emission rates that the EPA has identified. Those state plans are due in summer 2016. The EPA is proposing to allow, upon reasonable request, one-year extensions for states proposing individual plans and two-year extensions for states proposing to submit multi-state plans. OTP is participating with other stakeholders in efforts to shape the final performance standards for new, modified and reconstructed, and existing power plants both at the federal level and, where applicable, at the state level. It is not possible to determine, at this time, the potential impact to OTP of these future regulations on new, modified or reconstructed, or existing sources.

MANUFACTURING

Competition from foreign and domestic manufacturers, the price and availability of raw materials 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 have increased significantly and may continue to increase. 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.

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 approximately 98% of our total purchases of PVC resin in 2014 and approximately 93% of our total purchases of PVC resin in 2013. 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 PVC pipe manufacturers, but also against ductile iron, steel, concrete and clay 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.

Reductions 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. Reductions in PVC resin prices could negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of our finished goods inventory.

Certain PVC resin producers in the United States have announced approximately 1.2 billion pounds of resin production capacity additions to support the global market for PVC resin. These capacity additions are expected to come on line by the end of 2016. 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 three separate generating units. The oldest Hoot Lake Plant generating unit, constructed in 1948 (7,500 kW nameplate rating), was retired on December 31, 2005. A second unit was added in 1959 (53,500 kW nameplate rating) and a third unit was 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. The two generating units in operation have a combined nameplate rating of 128,500 kW.

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, 2014 OTP’s transmission facilities, which are interconnected with lines of other public utilities, consisted of 439 miles of 345 kV lines; 486 miles of 230 kV lines; 876 miles of 115 kV lines; and 3,962 miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of 48 miles of the 345 kV lines, with Minnkota Power Cooperative retaining title to the original 230 kV construction. 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 14.1% of 106 miles of energized line in the Fargo-Monticello 345 kV project and approximately 4.8% of 289 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 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 it 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 the Company's consolidated financial position, results of operations or cash flows.

Item 3A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF MARCH 2, 2015)

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, or has served as a director on the Company's board of directors.

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
Edward J. McIntyre (64)	9/8/11	Present:	Chief Executive Officer
Charles S. MacFarlane (50)	4/14/14	Present:	President and Chief Operating Officer
George A. Koeck (62)	4/10/00	Present:	Senior Vice President, General Counsel and Corporate Secretary
Kevin G. Moug (55)	4/9/01	Present:	Chief Financial Officer and Senior Vice President
Timothy J. Rogelstad (48)	4/14/14	Present:	Senior Vice President, Electric Platform
John Abbott (56)	2/11/15	Present:	Senior Vice President, Manufacturing and Infrastructure Platform

On September 8, 2011 the Company's board of directors appointed current director Edward J. (Jim) McIntyre to serve as interim President and Chief Executive Officer. On January 3, 2012, the Company's board of directors appointed Mr. McIntyre to serve as permanent President and Chief Executive Officer of the Company. Mr. McIntyre is retired Vice President and former Chief Financial Officer of Xcel Energy, Inc. He has been a member of the board of directors since 2006. He ceased serving as President on the appointment of Charles S. MacFarlane as President and Chief Operating Officer of the Company, effective April 14, 2014. On February 5, 2014 the Company announced that Mr. McIntyre expects to retire as Chief Executive Officer of the Company and as a member of the Company's board of directors at the Company's annual shareholder meeting in 2015 and that Mr. MacFarlane is expected to be named as Mr. McIntyre's successor at that time.

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 since 2003 and its Chief Executive Officer since 2007. 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 and Infrastructure Platform, and President of Varistar. For the past eight years Mr. Abbott has served as an officer and group vice president at Standex International Corporation (Standex), a group of restaurant equipment companies. During the past five years, Mr. Abbott served as Group Vice President, Food Service Equipment Group at Standex. 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.

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 on Page 36 of this Annual Report on Form 10-K under the heading "Selected Financial Data," on Page 97 under the heading "Retained Earnings and Dividend Restriction" and on Page 119 under the heading "Supplementary Financial Information." The Company does not have a publicly announced stock repurchase program. The following table shows common shares that were surrendered to the Company by employees during the three months ended December 31, 2014 to pay taxes in connection with the vesting of restricted shares under the Company's 1999 Stock Incentive Plan and 2014 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
October 2014	--	--
November 2014	--	--
December 2014	4,427	$ 29.66
Total	4,427	

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 Index (EEI) over the same period (assuming the investment of $100 in each vehicle on December 31, 2009, and reinvestment of all dividends).

	2009	2010	2011	2012	2013	2014
OTC	$100.00	$96.16	$99.36	$118.76	$144.97	$159.75
EEI	$100.00	$107.04	$128.43	$131.11	$147.17	$191.00
NASDAQ	$100.00	$117.55	$117.91	$137.29	$183.26	$206.09

Item 6. SELECTED FINANCIAL DATA

(thousands, except number of shareholders and per-share data)	2014	2013	2012	2011	2010
Revenues					
Electric	$407,743	$373,540	$350,765	$342,727	$344,379
Manufacturing	219,583	204,997	208,965	189,459	143,072
Plastics	172,050	164,957	150,517	123,669	96,945
Intersegment Eliminations	(114)	(80)	(82)	(174)	(446)
Total Operating Revenues	$799,262	$743,414	$710,165	$655,681	$583,950
Net Income from Continuing Operations	$56,883	$48,595	$46,034	$36,546	$26,526
Net Income (Loss) from Discontinued Operations	840	2,270	(51,307)	(49,789)	(27,870)
Net Income (Loss)	$57,723	$50,865	$(5,273)	$(13,243)	$(1,344)
Operating Cash Flow from Continuing Operations	$125,769	$142,408	$155,026	$94,008	$111,280
Operating Cash Flow - Continuing and Discontinued Operations	112,474	147,781	233,547	104,383	105,017
Capital Expenditures - Continuing Operations	163,582	159,833	114,186	64,715	52,774
Total Assets	1,791,279	1,596,019	1,602,337	1,700,522	1,770,555
Long-Term Debt	498,489	389,589	421,680	471,915	430,805
Basic Earnings Per Share - Continuing Operations (1)	1.56	1.33	1.25	1.00	0.72
Basic Earnings (Loss) Per Share - Total (1)	1.58	1.39	(0.17)	(0.40)	(0.06)
Diluted Earnings Per Share - Continuing Operations (1)	1.55	1.33	1.25	0.99	0.72
Diluted Earnings (Loss) Per Share - Total (1)	1.57	1.39	(0.17)	(0.40)	(0.06)
Return on Average Common Equity (2)	10.4 %	9.5 %	(1.1)%	(2.3)%	(0.3)%
Dividends Declared Per Common Share	1.21	1.19	1.19	1.19	1.19
Dividend Payout Ratio	77 %	86 %	—	—	—
Common Shares Outstanding - Year End	37,218	36,272	36,168	36,102	36,003
Number of Common Shareholders (3)	14,134	14,252	14,584	14,687	14,848

(1) Based on average number of shares outstanding.
(2) Earnings available for common shares divided by the 13-month average of month-end common equity balances.
(3) 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 2014, 2013 and 2012 was 77%, 80% and 85%, respectively, from our electric utility business and 23%, 20% and 15%, 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 segment. 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.

We have worked to realign our portfolio of businesses and refocus our capital investment in the electric utility. Over the last four years we sold several businesses in execution of our announced strategy. In 2011 we sold Idaho Pacific Holdings, Inc. (IPH), our Food Ingredient Processing segment business, and E.W. Wylie Corporation (Wylie), our trucking company which was included in our Wind Energy segment. In January 2012 we sold the assets of Aviva Sports, Inc. (Aviva), a recreational equipment manufacturer and wholly owned subsidiary of Shrco, Inc. (Shrco), our former waterfront equipment manufacturer. In February 2012 we sold DMS Health Technologies, Inc. (DMS), our Health Services segment business. In November 2012 we completed the sale of the assets of IMD, Inc. (IMD), our former wind tower manufacturer, and we exited the wind tower manufacturing business. On February 8, 2013 we sold substantially all of the assets of Shrco. On December 31, 2014 we were in the process of negotiating sales of Foley Company (Foley) and Aevenia, Inc. (Aevenia), our Construction segment subsidiaries. These companies met the criteria to be classified as held for sale and, as such, they are being reported as discontinued operations as of December 31, 2014.

In evaluating our portfolio of operating companies, we look for the following characteristics:

A threshold level of net earnings and a return on invested capital in excess of our weighted average cost of capital.
A strategic differentiation from competitors and a sustainable cost advantage.
A stable or growing industry.
An ability to quickly adapt to changing economic cycles.
A strong management team committed to operational excellence.

Major growth strategies and initiatives in our future include:

Planned capital budget expenditures of up to $775 million for the years 2015 through 2019, of which $665 million are for capital projects at Otter Tail Power Company (OTP), which includes $238 million for transmission projects designated by the Midcontinent Independent System Operator, Inc. (MISO) as Multi-Value Projects (MVPs), $105 million for natural gas-fired generation to replace Hoot Lake Plant capacity and $53 million for the remainder of OTP's share of the Big Stone Plant air quality control system (AQCS). The remainder of the OTP 2015-2019 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.
A $33.3 million spending commitment at BTD Manufacturing, Inc. (BTD), our custom metal fabricator, to expand its Minnesota facilities. The expansion will provide for growth in BTD's stamping and tooling business and will accommodate the addition of painting and more complex assembly services for BTD's customers.
Continued investigation and evaluation of organic growth opportunities and evaluation of opportunities to allocate capital to potential acquisitions in our Manufacturing segment.

In 2014:

Our net cash from continuing operations was $125.8 million.
We raised equity totaling $25.6 million from the sale of 519,636 shares of common stock through our At-the-Market offering program and the issuance of 370,717 shares of common stock through our stock plans.
Our Electric segment net income increased 14.2% to $43.7 million from $38.2 million in 2013.
Our Manufacturing segment net income decreased 18.3% to $9.4 million from $11.5 million in 2013. Manufacturing segment net income in 2014 was negatively impacted by a loss of $1.7 million, net-of-tax, related to abandonment of leased property and the write-off of associated leasehold improvements in connection with implementation of a facilities alignment and optimization strategy.
Our Plastics segment net income decreased 12.5% to $12.1 million from $13.8 million in 2013.

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

(in thousands)	2014	2013
Operating Revenues:		
Electric	$407,629	$373,462
Manufacturing and Plastics	391,633	369,952
Total Operating Revenues	$799,262	$743,414
Net Income (Loss) From Continuing Operations:		
Electric	$43,684	$38,236
Manufacturing and Plastics	21,446	25,266
Corporate	(8,247)	(14,907)
Total Net Income From Continuing Operations:	$56,883	$48,595

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Revenues increased in each of our Electric, Manufacturing and Plastics segments in 2014 resulting in a 7.5% increase in consolidated revenues compared with 2013. Revenues from our Electric segment increased $34.2 million reflecting: (1) a $13.4 million increase in retail revenue related to increases in Fuel Clause Adjustment (FCA) revenues and fuel and purchased power costs recovered in base rates, (2) a $10.7 million increase in Environmental Costs Recovery rider revenue, and (3) a $6.3 million increase in Transmission Cost Recovery rider revenues. A $19.8 million increase in revenues at BTD was partially offset by a $5.2 million decrease in revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, resulting in a $14.6 million net increase in revenues from our Manufacturing segment. Revenues from our Plastics segment increased $7.1 million as a result of a 2.4% increase in revenue per pound of polyvinyl chloride (PVC) pipe sold in combination with a 1.9% increase in pounds of PVC pipe sold.

The following table sets forth actual results for 2014 and 2013 on a GAAP basis and also on a non-GAAP basis excluding the effects of lease abandonment and early termination costs and the goodwill impairment charge at Foley in 2014 and the early retirement of debt in 2013. We reported $1.72 of diluted earnings per share on a non-GAAP basis which was within our most recent guidance range.

Diluted Earnings Per Share		
	2014	2013
Before Classification of Construction as Discontinued		
Electric	$1.19	$1.05
Manufacturing	$0.25	$0.32
Plastics	$0.33	$0.38
Construction Companies – Before Goodwill Impairment Charge[1]	$0.17	$0.04
Corporate	($0.22)	($0.42)
Non-GAAP Basis[1]	$1.72	$1.37
Remove:		
Construction Companies – Before Goodwill Impairment Charge[1]	($0.17)	($0.04)
Continuing Operations – GAAP Basis	$1.55	$1.33
Add back:		
Cost of BTD Otsego Lease Abandonment – Manufacturing	$0.05	
Cost of Airplane Lease Termination – Corporate	$0.04	
Loss on Debt Extinguishment – Corporate		$0.17
Continuing Operations – Non-GAAP Basis[1]	$1.64	$1.50
Discontinued Operations:		
Construction Companies – Before Goodwill Impairment Charge	$0.17	$0.04
Other	$ --	$0.02
Discontinued Operations – Non-GAAP Basis[1]	$0.17	$0.06
Foley Company Goodwill Impairment Charge	($0.15)	
Discontinued Operations – GAAP Basis	$0.02	$0.06
Total Non-GAAP Basis[1]	$1.81	$1.56
Less Adjustments:		
Cost of BTD Otsego Lease Abandonment – Manufacturing	($0.05)	
Cost of Airplane Lease Termination – Corporate	($0.04)	
Loss on Debt Extinguishment – Corporate		($0.17)
Foley Company Goodwill Impairment Charge – Discontinued Operations	($0.15)	
Total – GAAP Basis	$1.57	$1.39

[1] Charge items added back to GAAP-based diluted earnings per share above are shown to provide an indication of what earnings would be without these items and to indicate a

baseline for comparison of past earnings and projection of potential future earnings. Management understands that there are material limitations on the use of non-GAAP measures. Non-GAAP measures are not substitutes for GAAP measures for the purpose of analyzing financial performance. Non-GAAP measures are not in accordance with, or an alternative for, measures prepared in accordance with, generally accepted accounting principles and may be different from non-GAAP measures used by other companies. In addition, non-GAAP measures are not based on any comprehensive set of accounting rules or principles. This information should not be construed as an alternative to the reported results, which have been determined in accordance with GAAP.

Following is a more detailed analysis of our operating results by business segment for the years ended December 31, 2014, 2013 and 2012, followed by a discussion of our financial position at the end of 2014 and our outlook for 2015.

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 2014, 2013 and 2012 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)	2014	2013	2012
Operating Revenues:			
Electric	$114	$78	$76
Nonelectric	--	2	6
Cost of Products Sold	45	10	54
Other Nonelectric Expenses	69	70	28

ELECTRIC

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

(in thousands)	2014	% change	2013	% change	2012
Retail Sales Revenues	$361,100	10	$328,758	7	$308,530
Wholesale Revenues – Company Generation	11,160	(25)	14,846	15	12,951
Net Revenue – Energy Trading Activity	1,031	(36)	1,615	13	1,426
Other Revenues	34,452	22	28,321	2	27,858
Total Operating Revenues	$407,743	9	$373,540	6	$350,765
Production Fuel	67,216	(6)	71,248	7	66,284
Purchased Power – System Use	65,848	27	52,006	6	49,184
Other Operation and Maintenance Expenses	141,936	6	133,395	10	121,069
Asset Impairment	--	--	--	--	432
Depreciation and Amortization	44,076	2	43,125	3	42,051
Property Taxes	12,607	11	11,311	6	10,720
Operating Income	$76,060	22	$62,455	2	$61,025
Electric kilowatt-hour (kwh) Sales (in thousands)					
Retail kwh Sales	4,695,062	5	4,487,541	6	4,240,789
Wholesale kwh Sales – Company Generation	273,454	(42)	471,474	(1)	476,637
Wholesale kwh Sales – Purchased Power Resold	17,303	(90)	172,404	95	88,637
Heating Degree Days	7,218	(2)	7,366	37	5,377
Cooling Degree Days	375	(27)	516	(20)	641

2014 compared with 2013

Retail sales revenue increased $32.3 million mainly as a result of:

A $13.4 million increase in FCA revenues and fuel and purchased power costs recovered in base rates driven by increased kwh purchases to meet higher retail kwh sales demand along with higher prices for purchased power.

A $10.7 million increase in Environmental Cost Recovery rider revenues related to earning a return in Minnesota, North Dakota and South Dakota on increasing amounts invested in the AQCS under construction at Big Stone Plant.

A $6.3 million increase in Transmission Cost Recovery rider revenues related to recovering costs and earning returns on increased investments in transmission plant.

A $5.3 million increase in revenue related to a 4.6% increase in retail kwh sales mainly driven by an increase in sales to pipeline and commercial customers.

offset by:

A $1.5 million decrease in revenues related to reductions in financial incentives expected under conservation improvement programs.

A $1.1 million decrease in Renewable Resource Adjustment (RRA) rider revenues in North Dakota as a result of declining book values of renewable assets due to depreciation and an increase in federal Production Tax Credits (PTCs) used in 2014, which reduce RRA revenue requirements.

A $1.1 million reduction in Big Stone II cost recovery rider revenues as the North Dakota share of abandoned plant costs were fully recovered as of March 31, 2014.

Wholesale electric revenues from company-owned generation decreased $3.7 million as a result of a 42.0% reduction in wholesale kwh sales, partially offset by a 29.6% increase in revenue per wholesale kwh sold. The decrease in wholesale kwh sales was the result of having less generation available for sale in the second and third quarters of 2014 as a result of the extended maintenance shutdown of Hoot Lake Plant, which was offline for most of the second and third quarters of 2014, and curtailments in generation at Big Stone Plant to conserve fuel in response to delayed coal shipments in the third quarter of 2014. The increase in wholesale prices was driven by increased wholesale market demand resulting from cold weather in the first quarter of 2014.

Net revenue from energy trading activities, including net marked-to-market gains and losses on forward energy contracts, decreased $0.6 million mainly as a result of decreased trading activity and the incurrence of losses on contracts entered into and settled in the first half of 2014. OTP discontinued 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 operating revenues increased $6.1 million mainly as a result of increases in MISO transmission tariff revenues related to increased investment in regional transmission lines and driven in part by returns on and recovery of Capital Expansion 2020 (CapX2020) and MISO-designated MVP investment costs and operating expenses.

Production fuel costs decreased $4.0 million as a result of an 8.0% decrease in kwhs generated from OTP’s steam-powered and combustion turbine generators. The decrease in kwh generation was mainly due to the extended maintenance shutdown of Hoot Lake Plant in the second and third quarters of 2014 and curtailments in generation at Big Stone Plant to conserve fuel in response to delayed coal shipments in the third quarter of 2014.

The cost of purchased power to serve retail customers increased $13.8 million due to a 19.2% increase in kwhs purchased in combination with a 6.2% increase in cost per kwh purchased. The increase in kwhs purchased was driven by increased demand from retail customers. The increase in cost per kwh purchased was driven by increased wholesale market demand resulting from colder weather in the first quarter of 2014. The level of company-owned generation dedicated to serving retail customers was essentially unchanged in 2014 compared with 2013, despite the reductions in generation at Hoot Lake and Big Stone plants. The reduction in generation from Big Stone Plant was mostly offset by an increase in kwhs generated at Coyote Station, while the reduced availability of Hoot Lake Plant had more of a negative impact on wholesale sales.

Electric operating and maintenance expenses increased $8.5 million as a result of:

A $4.8 million increase in contracted maintenance and material and supplies costs at Hoot Lake Plant related to a scheduled maintenance shutdown which was extended several weeks due to unanticipated maintenance issues encountered during the shutdown.

A $3.6 million increase in MISO transmission tariff charges related to increasing investments by others in regional CapX2020 and MISO-designated MVP transmission projects.

A $1.5 million increase in expenditures for transmission line maintenance for vegetation control and preservation of poles.

A $0.8 million increase in material and supply and contractor costs for other generation plant maintenance.

A $0.5 million increase in transportation expenses mainly related to a decrease in vehicle usage on capital projects between the years.

offset by:

A $1.6 million reduction in labor and benefit expenses mainly due to decreases in pension and retirement health benefit costs resulting from higher discount rates on projected benefit obligations.

A $1.1 million reduction in the amortization of the North Dakota share of Big Stone II costs which were fully recovered as of March 31, 2014.

The $1.0 million increase in depreciation expense was primarily driven by higher software related costs currently being amortized and increased capital replacement costs on OTP's wind farms.

The $1.3 million increase in property tax expense is due to higher property valuations for transmission and distribution property in Minnesota and South Dakota.

In December 2014, a boiler feed pump failure and ensuing fire occurred at Coyote Station. Initial repairs made in December have enabled the station to operate at reduced load. OTP's share of equipment repair and replacement costs not covered by insurance are estimated to be approximately $340,000 and will be capitalized. Any power purchased to make up for reduced generation at Coyote Station is expected to be subject to recovery through jurisdictional FCA mechanisms in place in each of the states OTP serves.

<u>2013 compared with 2012</u>
Retail sales revenues increased by $20.2 million as a result of:
A $6.6 million increase in revenues due to significantly colder weather in 2013 compared to 2012, which drove a 5.8% increase in retail kwh sales.
A $7.0 million increase in retail revenue related to increases in fuel clause adjustment revenues and fuel and purchased power costs recovered in base rates, which was driven by increased kwh generation to meet higher retail demand and higher prices for purchased power.
A $2.8 million increase in Transmission Cost Recovery rider revenues resulting from increased investment in transmission lines.
A $2.3 million increase in Environmental Cost Recovery rider revenues related to earning a return in North Dakota on funds invested in the construction of a new air quality control system at Big Stone Plant.
A $1.5 million increase in conservation improvement program recovered costs and incentives earned as a result of the effectiveness of OTP's programs.

Wholesale electric revenues from company-owned generation increased $1.9 million, despite a 1.1% decline in wholesale kwh sales, due to a 15.9% increase in the average price per wholesale kwh sold, which was driven by higher natural gas prices and increased demand resulting from colder weather in 2013.

Net revenue from energy trading activities, including net mark-to-market gains on forward energy contracts, increased $0.2 million mainly as a result of an increase in unrealized mark-to-market gains on open energy contracts scheduled to settle in January and February of 2014.

Other electric operating revenues increased $0.5 million reflecting a $2.6 million increase in MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) revenues related to increasing investments in regional transmission projects, mainly CapX2020 projects, offset by a $2.2 million reduction in revenue from shared use of transmission facilities with other regional transmission providers. 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.

The $5.0 million increase in production fuel costs resulted from a 10.8% increase in kwhs generated from OTP's steam-powered and combustion turbine generators, partially offset by a 3.0% reduction in the cost of fuel per kwh generated. The increase in kwh generation was facilitated by improved availability of all of OTP's steam-powered generation units in 2013. The increase in generation was dedicated entirely to serving increased demand from OTP's retail customers driven by colder weather in 2013. The cost of purchased power to serve retail customers increased $2.8 million, despite a 2.1% decrease in kwhs purchased, due to an 8.0% increase in costs per kwh purchased driven by increased demand and higher fuel prices for natural-gas fired generation.

Electric operating and maintenance expenses increased $12.3 million as a result of the following:
A $4.0 million increase in MISO transmission tariff charges related to increasing investments in regional CapX2020 and MISO-designated MVP transmission projects.

A $2.9 million increase in corporate costs allocated to OTP due, in part, to changes in allocation factors resulting from the corporation's recent divestitures.
A $2.5 million increase in labor and benefit expenses due to increases in salaries and wages, a reduction in capitalized labor in 2013 compared with 2012 and an increase in pension benefit costs resulting from a reduction in the discount rate related to projected benefit obligations.
A $0.8 million increase in transportation costs related to higher gasoline prices and a reduction in capitalized transportation expenses in 2013.

A $0.7 million discount on OTP's investment in abandoned transmission plant that was transferred in 2013 from construction work in progress to a regulatory asset account for future recovery.
A $0.4 million increase in conservation improvement program costs.
A $1.0 million increase in expenditures for insurance, outside services, vegetative maintenance, power plant water supply and bad debt expense in 2013.

Otter Tail Energy Services Company (OTESCO) recorded a $0.4 million asset impairment charge related to wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota in the first quarter of 2012 as a potential sale of the rights did not occur as expected. OTESCO ceased operations as of December 31, 2012.

The $1.1 million increase in depreciation expense is mainly related to CapX2020 transmission lines being placed in service in 2013.

Property taxes increased $0.6 million due to higher property value assessments in Minnesota and South Dakota.

MANUFACTURING

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

(in thousands)	2014	% change	2013	% change	2012
Operating Revenues	$219,583	7	$204,997	(2)	$208,965
Cost of Products Sold	169,033	10	154,235	(2)	157,437
Lease Exit Costs	2,843	--	--	--	--
Other Operating Expenses	20,497	9	18,820	3	18,233
Depreciation and Amortization	10,518	(6)	11,194	(8)	12,208
Operating Income	$16,692	(20)	$20,748	(2)	$21,087

2014 compared with 2013
The increase in revenues in our Manufacturing segment in 2014 compared with 2013 relates to the following:

Revenues at BTD increased $19.8 million (11.8%) mainly as a result of increased sales to customers in recreational, lawn and garden and energy-related end markets.
Revenues at T.O. Plastics decreased $5.2 million (13.6%) mainly due to discontinuing a cost-intensive, low-margin product packing process performed for a customer prior to 2014.

The increase in cost of products sold in our Manufacturing segment in 2014 compared with 2013 consists of the following:

Cost of products sold at BTD increased $19.3 million as a result of increased material and labor costs related to an increase in sales volume, increased product handling costs and the incurrence of additional tooling costs to repair and refurbish several dies in 2014, which had the effect of reducing BTD's gross margin percentage despite its increase in sales and gross margin.
Cost of products sold at T.O. Plastics decreased $4.5 million mainly as a result of decreased material costs related to the product packaging process that was discontinued in 2014.

The increase in other operating expenses in our Manufacturing segment in 2014 compared with 2013 relates to the following:

Operating expenses at BTD increased $4.2 million in 2014, which includes:

- o A loss of $2.8 million related to BTD's abandonment of leased property and the write-off of associated leasehold improvements in connection with implementation of a facilities realignment and optimization strategy.
- o A $0.5 million increase in allocated corporate costs.
- o Increases totaling $1.0 million in contracted services, labor and benefit costs and travel expenses, mainly related to an increase in time and external resources devoted to training and talent development.

Operating expenses at T.O. Plastics increased $0.3 million mainly due to an increase in allocated corporate costs.

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Depreciation expense decreased $0.4 million at BTD and $0.3 million at T.O. Plastics as a result of certain assets reaching the end of their depreciable lives.

<u>2013 compared with 2012</u>
The decrease in revenues in our Manufacturing segment in 2013 compared with 2012 relates to the following:

Revenues at BTD decreased $1.7 million (1.0%) as a result of lower sales volume due to reduced demand from customers in end markets serving the construction and energy industries, partially offset by increased sales to customers in end markets serving the recreational equipment and agricultural industries.

Revenues at T.O. Plastics decreased $2.3 million (5.7%) due to the discontinuance of a packaging product for a major customer who took production of the product in-house, partially offset by increased sales volumes in certain horticultural and industrial product lines.

The decrease in cost of products sold in our Manufacturing segment in 2013 compared with 2012 consists of the following:

Cost of products sold at BTD decreased by $0.1 million as a reduction in costs related to lower sales volumes was mostly offset by increases in labor costs due to a ramp up in hiring personnel in anticipation of larger sales volumes in 2014.

Cost of products sold at T.O. Plastics decreased $3.1 million as a result of reductions in raw material costs and reduced conversion costs related to productivity improvements.

The increase in other operating expenses in our Manufacturing segment in 2013 compared with 2012 relates to the following:

Operating expenses at BTD increased $0.2 million mainly as a result of upgrades and enhancements made to BTD's communications systems.

Operating expenses at T.O. Plastics increased $0.4 million as a result of increased hiring costs associated with new management team members and increased sales incentives and commissions.

Depreciation expense decreased mainly as a result of certain assets at BTD's Illinois plant being fully depreciated early in 2013.

PLASTICS

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

(in thousands)	2014	% change	2013	% change	2012
Operating Revenues	$172,050	4	$164,957	10	$150,517
Cost of Products Sold	139,081	8	129,042	15	112,662
Operating Expenses	9,292	8	8,571	(2)	8,784
Depreciation and Amortization	3,364	--	3,350	7	3,118
Operating Income	$20,313	(15)	$23,994	(8)	$25,953

2014 compared with 2013

The $7.1 million increase in Plastics segment revenue is the result of a 2.4% increase in revenue per pound of PVC pipe sold, combined with a 1.9% increase in pounds of PVC pipe sold. States with significant increases in sales were Minnesota, Illinois, California, Colorado and New Mexico. Cost of products sold increased by $10.0 million due to the increase in sales volume and a 5.8% increase in the cost per pound of pipe sold primarily related to higher PVC resin prices. The increase in resin prices could not be fully recovered through increased pipe prices due to competitive market conditions. The reduction in margins combined with a $0.7 million increase in operating expenses mainly related to an increase in allocated corporate costs resulted in the $3.7 million decline in Plastics segment operating income between the years.

2013 compared with 2012

The increase in Plastics segment revenue is the result of a 12.0% increase in pounds of PVC pipe sold, partially offset by a 2.2% decrease in revenue per pound of pipe sold. Sales volume increased as construction and housing markets continued to improve in the South Central and Southwest regions of the United States and construction activity increased in the North Central United States in the second half of 2013. The increase in costs of products sold was mostly due to the increase in pounds of pipe sold, but also reflects a 2.2% increase in the cost per pound of pipe sold related to higher PVC resin costs driven by high global demand and an increase in the cost of ethylene, a key ingredient in the production of PVC resin. The reduction in operating expenses reflects a reduction in incentive compensation related to the decrease in operating income between the years. The increase in depreciation and amortization expense is related to equipment replacement costs incurred in 2013 at our Arizona plant associated with increased production levels and machine usage.

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)	2014	% change	2013	% change	2012
Airplane Rent and Lease Exit Costs	$3,012	--	$595	--	$595
Other Operating Expenses	10,406	(14)	12,158	(4)	12,689
Depreciation and Amortization	116	(44)	207	(57)	480

The $0.7 million increase in Corporate operating expenses in 2014 compared with 2013 reflects:
A $2.4 million increase related to the early termination of an airplane lease in the second quarter of 2014, as recent divestitures reduced the need for the airplane.
A $0.2 million increase in expenses, meetings and educational materials related to talent development and leadership training.
offset by:
A $1.9 million increase in corporate operating expenses allocated to the corporation’s operating segments.

The $0.5 million decrease in Corporate operating expenses in 2013 compared with 2012 reflects:
A $2.9 million increase in various corporate expenses allocated or directly charged to our Electric segment due, in part, to changes in allocation factors resulting from the corporation’s recent divestitures.
A $0.5 million reduction in insurance costs and contracted services.
offset by:
A $2.4 million increase in incentive and performance award accruals related to our improved operating results and the strong performance of our common stock price as measured against the stock performances of our peer group of companies in the Edison Electric Institute Index.
A $0.5 million increase in labor costs mainly related to staffing additions at Varistar Corporation (Varistar).

CONSOLIDATED INTEREST CHARGES

The $2.7 million increase in interest charges in 2014 compared with 2013 primarily reflects:
A $6.4 million increase in interest expense 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 $0.3 million reduction in capitalized interest due to OTP being granted a return on funds invested in the Big Stone Plant AQCS through environmental cost recovery riders approved in Minnesota and North Dakota in December 2013, which resulted in the discontinuance of capitalized interest on the Minnesota share of the project and an increase in interest expense between the years.
offset by:
A $3.7 million reduction in interest expense related to the early retirement of $47.7 million of our 9.0% unsecured notes due December 15, 2016, in November 2013.
A $0.3 million reduction in interest expense related to the February 27, 2014 repayment of OTP’s $40.9 million unsecured term loan under a Credit Agreement with JPMorgan Chase Bank, N.A., which was entered into and fully

drawn on March 1, 2013 and bore interest at LIBOR plus 0.875%.

The $4.9 million decrease in interest charges in 2013 compared with 2012 reflects the following:

A $2.7 million decrease in interest and debt amortization charges related to the retirement of the Cascade Note (as described below) on July 13, 2012.
A $0.6 million net decrease in interest charges as a result of OTP's debt refinancing on March 1, 2013, when it borrowed $40.9 million under an unsecured term loan due January 15, 2015, bearing interest at LIBOR plus 0.875% and used a portion of the proceeds to redeem its $20.1 million in outstanding 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds and $5.1 million in outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds.
A $0.5 million reduction in interest charges as a result of the early retirement in November 2013 of $47.7 million of our outstanding 9.000% Notes.
A $0.4 million reduction in line of credit non-use fees as a result of reducing the Otter Tail Corporation line limit by $50 million in October 2012.
A $0.3 million increase in capitalized interest expense at OTP related to OTP's increasing investment in the Big Stone Plant AQCS.
A $0.3 million decrease in interest on the Company's and OTP's line of credit borrowings.

LOSS ON EARLY RETIREMENT OF DEBT

On November 6 and 25, 2013 we purchased, in two separate transactions, approximately $47.7 million of our outstanding $100 million 9.000% Notes due December 15, 2016 (the 2016 Notes). The purchased Notes (Purchased 2016 Notes) were subsequently retired and are no longer outstanding. The price we paid for the Purchased 2016 Notes was approximately $59.4 million, which includes the principal amount of the Purchased 2016 Notes, plus accrued interest of approximately $1.8 million through the respective purchase dates and a negotiated premium of approximately $9.9 million (which was less than the redemption premium we would have been required to pay under the terms of the 2016 Notes). On repayment, $0.4 million in unamortized debt expense related to the 2016 Notes was immediately recognized as expense along with the $9.9 million negotiated premium. We used cash on hand to fund the purchase of the Purchased 2016 Notes. The amount of the debt retired as a result of these transactions is approximately equivalent to the remaining amount of debt that was associated with the operating companies we divested over the last two years. The retirement of the Purchased 2016 Notes reduces pre-tax interest expense by approximately $4.3 million per year for the remaining three-year life of the Purchased 2016 Notes. The $10.3 million ($6.2 million net-of-tax) loss on early retirement of debt had a negative impact on 2013 diluted earnings per share of $0.17.

On July 13, 2012 we prepaid in full our $50 million 8.89% Senior Unsecured Note due November 30, 2017 (the Cascade Note). The price to prepay the Cascade Note was $63.0 million which included the principal amount of the Cascade Note plus accrued interest of $0.5 million and a negotiated prepayment premium of $12.5 million. On repayment, $0.6 million in unamortized debt expense related to this note was immediately recognized as expense along with the $12.5 million negotiated prepayment premium. The $13.1 million ($7.9 million net-of-tax) loss on early retirement of debt had a negative impact on 2012 diluted earnings per share of $0.22.

CONSOLIDATED OTHER INCOME

Other income was $3.6 million for 2014 compared with $4.1 million for 2013. The decrease in other income is due to a $0.3 million decrease in allowance for equity funds used in construction (AFUDC) related to costs incurred in the construction of the new AQCS at OTP's Big Stone Plant, which were subject to AFUDC in 2013 but not in 2014 as returns on amounts invested in this project are now being recovered under Environmental Cost Recovery riders implemented in North Dakota in 2013 and in Minnesota and South Dakota in 2014, and a $0.2 million reduction in investment income.

Other income was $4.1 million for 2013 compared with $3.9 million for 2012.

CONSOLIDATED INCOME TAXES

Income tax expense - continuing operations was $16.6 million in 2014 compared with $12.5 million in 2013 and $7.2 million in 2012. 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 years ended December 31, 2014, 2013 and 2012:

	For the Year Ended December 31,		
(in thousands)	2014	2013	2012
Tax Computed at Federal Statutory Rate	$25,704	$21,389	$18,622
Increases (Decreases) in Tax from:			
Federal PTCs	(7,517)	(6,612)	(6,695)
State Income Taxes Net of Federal Income Tax Benefit	1,993	1,561	(249)
Section 199 Domestic Production Activities Deduction	(1,026)	--	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(849)	(863)	(891)
Dividend Received/Paid Deduction	(622)	(632)	(656)
Investment Tax Credit Amortization	(597)	(597)	(720)
Allowance for Funds Used During Construction – Equity	(505)	(638)	(409)
Corporate Owned Life Insurance	(354)	(856)	(585)
Tax Depreciation – Treasury Grant for Wind Farms	(152)	(304)	(304)
Differences Reversing in Excess of Federal Rates	(106)	(100)	(143)
Impact of Medicare Part D Change	--	--	(584)
Permanent and Other Differences	588	168	(213)
Total Income Tax Expense – Continuing Operations	$16,557	$12,516	$7,173
Effective Income Tax Rate – Continuing Operations	22.5 %	20.5 %	13.5 %

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 13.8% in 2014 compared with 2013. 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 December 31, 2014 we were in the process of negotiating the sales of Foley and Aevenia, our Construction segment subsidiaries. We have entered into signed letters of intent to sell the companies within our Construction segment and expect to close on the respective transactions by the end of the first quarter of 2015. These companies meet the criteria to be classified as held for sale and, as such, they are being reported as discontinued operations as of December 31, 2014. We recognized a $5.6 million goodwill impairment loss on Foley in 2014 based on Foley’s indicated market price. We expect to record a gain on the sale of Aevenia when the sale closes.

On February 8, 2013 we completed the sale of substantially all the assets of Shrco, formerly included in our Manufacturing segment, for approximately $13.0 million in cash and received a working capital true up of approximately $2.4 million in June 2013.

On January 18, 2012, we sold the assets of Aviva, a subsidiary of Shrco, for $0.3 million in cash. For discontinued operations reporting, Aviva’s results are included in Shrco’s consolidated results. On November 30, 2012 we completed the sale of the assets of IMD for total proceeds, net of commissions and selling costs, of $18.1 million. Prior to the sale, IMD was the only remaining entity in our former Wind Energy segment. On February 29, 2012 we completed the sale of DMS, our health services company, for $24.0 million in cash net of commissions and selling costs, which was reduced by a $1.7 million working capital settlement paid to the buyer in February 2013. The DMS working capital settlement was estimated to be $1.9 million at the time of the sale. The final settlement resulted in recording a $0.2 million gain on the sale of DMS in the first quarter of 2013. DMS was the only business in our former Health Services segment.

On December 29, 2011 we completed the sale of Wylie for approximately $25.0 million in cash. Wylie was included in our former Wind Energy segment. On May 6, 2011 we completed the sale of IPH for approximately $86.0 million in cash. IPH was the only business in our former Food Ingredient Processing segment.

Our Wind Energy, Health Services, Food Ingredient Processing and Construction segments were eliminated as a result of the sales of IMD, DMS and IPH and the classifications of Foley and Aevenia as discontinued operations. The financial position, results of operations and cash flows of Foley, Aevenia, IMD, Wylie, Shrco, DMS and IPH are reported as discontinued operations in our consolidated financial statements. Following are summary presentations of the results of discontinued operations for the years ended December 31, 2014, 2013 and 2012:

For the Year Ended December 31, 2014

(in thousands)	Foley	Aevenia	IMD	Shrco	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

For the Year Ended December 31, 2013

(in thousands)	Foley	Aevenia	IMD	Wylie	Shrco	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$110,097	$39,813	$--	$--	$2,016	$--	$ (11)	$151,915
Operating Expenses	109,036	38,257	(988)	640	2,622	(269)	(11)	149,287
Interest Expense	249	207	--	--	--	--	(451)	5
Other Income (Deductions)	4	(5)	412	--	67	--	(5)	473
Income Tax Expense (Benefit)	331	518	370	(256)	(213)	108	178	1,036
Net Income (Loss) from Operations	485	826	1,030	(384)	(326)	161	268	2,060
Gain on Disposition Before Taxes	--	--	--	--	16	200	--	216
Income Tax Expense on Disposition	--	--	--	--	6	--	--	6
Net Gain on Disposition	--	--	--	--	10	200	--	210
Net Income (Loss)	$485	$826	$1,030	$(384)	$(316)	$361	$ 268	$2,270

For the Year Ended December 31, 2012

(in thousands)	Foley	Aevenia	IMD	Wylie	Shrco	DMS	IPH	Intercompany Transactions Adjustment	Total
Operating Revenues	$93,598	$55,494	$186,151	$--	$32,563	$16,362	$--	$ (2,032)	$382,136
Operating Expenses	109,493	51,873	184,462	179	36,163	14,741	--	(2,032)	394,879
Asset Impairment Charge	--	--	45,573	--	7,747	--	--	--	53,320
Interest Expense	688	351	5,787	--	1,553	279	--	(8,482)	176
Other Income	--	169	135	--	15	122	--	--	441
Income Tax (Benefit) Expense	(6,629)	1,174	(15,792)	13	(4,021)	1,734	106	3,393	(20,022)
	(9,954)	2,265	(33,744)	(192)	(8,864)	(270)	(106)	5,089	(45,776)

Net (Loss) Income from Operations									
Loss on Disposition Before Taxes	--	--	--	(62)	--	(5,154)	--	--	(5,216)
Income Tax Expense (Benefit) on Disposition	--	--	--	460	--	(145)	--	--	315
Net Loss on Disposition	--	--	--	(522)	--	(5,009)	--	--	(5,531)
Net (Loss) Income	$(9,954)	$2,265	$(33,744)	$(714)	$(8,864)	$(5,279)	$(106)	$ 5,089	$(51,307)

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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, aluminum 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, 2014 and December 31, 2013:

(in thousands)	Line Limit	In Use on December 31, 2014	Restricted due to Outstanding Letters of Credit	Available on December 31, 2014	Available on December 31, 2013
Otter Tail Corporation Credit Agreement	$150,000	$ 10,854	$ 274	$138,872	$149,341
OTP Credit Agreement	170,000	--	560	169,440	116,975
Total	$320,000	$ 10,854	$ 834	$308,312	$266,316

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, 2012 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 10, 2015. On May 14, 2012, we entered into a Distribution Agreement with J.P. Morgan Securities (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. In 2014 we received proceeds of $14,801,000 net of $535,000 paid to JPMS from the issuance of 519,636 shares under this program.

Equity or debt financing will be required in the period 2015 through 2019 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 flow 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.

Our common stock dividend payments have exceeded our net income (losses) in three of the last five years. 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 3, 2015 our board of directors increased the quarterly dividend from $0.3025 to $0.3075 per common share.

<u>2014 cash flows compared with 2013 cash flows</u>
Cash provided by operating activities of continuing operations was $125.8 million in 2014 compared with $142.4 million in 2013. The major contributing factors to the $16.6 million decrease in cash provided by operating activities between the periods was a $12.2 million increase in cash used for working capital items and a $10.0 million increase in discretionary contributions to our pension plan, offset by an $8.3 million increase in net income from continuing operations. The following major items contributed to the $12.2 million increase in cash used for working capital between the periods:

In the Plastics segment, finished goods and raw materials inventories increased $8.4 million in 2014 compared with an increase of $1.9 million in 2013. The increase in inventories in the Plastic segment in 2014 corresponds with higher resin costs at year-end 2014 compared with year-end 2013 and a buildup of inventory in the fourth quarter of 2014 in anticipation of increasing prices and increasing demand for PVC pipe in early 2015.
In the Electric segment, accounts payable related to operating activities decreased $0.4 million in 2014 compared to an increase of $6.6 million in 2013 as a result of several significant invoices and accrued liabilities outstanding at year-end 2013.

Net cash used in discontinued operations of $13.3 million in 2014 reflects a $13.6 million decrease in accounts payable and other current liabilities including billings in excess of cost at Foley in 2014 as advances received on a major project in 2013 were used to pay for project-related costs in 2014.

Net cash used in investing activities of continuing operations was $163.9 million in 2014 compared with $159.5 million in 2013, reflecting a $4.2 million increase in cash used for capital expenditures at BTD, as BTD began work on construction and modification of buildings at its Detroit Lakes and Lakeville, Minnesota locations in conjunction with the implementation of a facilities alignment and optimization strategy.

Net cash provided by financing activities of continuing operations was of $49.7 million in 2014 compared with net cash used in financing activities of continuing operations of $49.0 million in 2013. Net cash provided by financing activities of continuing operations in 2014 mainly reflects the issuance by OTP of $150 million in privately placed unsecured notes in two series on February 27, 2014, and the use of a portion of the proceeds of the notes to retire OTP's $40.9 million unsecured term loan and to repay short-term debt outstanding under the OTP Credit Agreement which was being used to finance OTP's construction activities. Financing activities in 2014 also reflect: (1) the payment of $44.3 million in common stock dividends, (2) OTP's repayment of $51.2 million in short-term debt under the OTP Credit Agreement outstanding on December 31, 2013, and (3) the borrowing of $10.9 million under the Otter Tail Corporation Credit Agreement to fund the working capital needs of our manufacturing and plastic pipe companies. Financing cash flows in 2014 also include $25.6 million in net cash proceeds from the issuance of common stock. In 2014, we began issuing common shares to meet the requirements of our dividend reinvestment and share purchase plan, employee stock ownership plan and employee stock purchase plan, rather than purchasing shares in the open market. In the second quarter of 2014 we began issuing common shares using our At-the-Market offering program under our Distribution Agreement with JPMS.

<u>2013 cash flows compared with 2012 cash flows</u>
Cash provided by operating activities from continuing operations was $142.4 million in 2013 compared with $155.0 million in 2012. The $12.6 million decrease in cash provided by operating activities from continuing operations reflects a $15.1 million decrease in cash provided by changes in accounts payables and other current liabilities between the years.

Net cash provided by discontinued operations of $78.5 million in 2012 is mainly from the monetization of IMD's working capital in 2012 after IMD's operations were discontinued. The proceeds generated by the monetization of

IMD’s working capital were used to pay down our line of credit after the line was used to repurchase the Cascade Note and to pay a $12.5 million repurchase premium to retire the Cascade Note prior to its maturity date.

Net cash used in investing activities of continuing operations was $159.5 million in 2013 compared to $112.5 million in 2012. The $47.0 million increase is mainly due to increases in cash used for capital expenditures of $47.9 million at OTP. OTP’s $149.5 million in capital expenditures in 2013 includes a significant level of expenditures for the construction of Big Stone Plant’s new AQCS and expenditures for the construction of two major CapX2020 transmission line projects, the Fargo–Monticello 345 kiloVolt (kV) Project and the Brookings–Southeast Twin Cities 345 kV Project. Net proceeds from the sale of discontinued operations of $12.8 million in 2013 reflect $14.5 million in net proceeds from the sale of the assets of our waterfront equipment manufacturing business less a $1.7 million working capital settlement paid to the buyer of DMS, which we sold in the first quarter of 2012.

Net investing cash flows from discontinued operations were $29.0 million in 2012. Net proceeds from the sales of DMS, IMD and Aviva were $42.2 million in 2012. Net cash used in investing activities of discontinued operations of $13.3 million in 2012 mainly reflects cash used by DMS to purchase assets held under operating leases.

Net cash used in financing activities of continuing operations of $49.0 million in 2013 includes $57.6 million used for the November 2013 early retirement of $47.7 million of our 9.000% Notes due December 15, 2016 and $43.8 million in common and preferred stock dividend payments, offset by the $51.2 million in proceeds from short term borrowings at OTP to fund its significant level of capital expenditures. On March 1, 2013 OTP used proceeds from a $40.9 million unsecured term loan to fund the redemption of all $25.1 million of the then outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds, and to pay off an intercompany note to Otter Tail Corporation that mirrored $15.5 million in outstanding cumulative preferred shares of Otter Tail Corporation, which were also redeemed on March 1, 2013.

Net cash used in financing activities of continuing operations of $108.1 million in 2012 includes $62.5 million used for the early retirement of the Cascade Note and $44.0 million for the payment of dividends on our outstanding common and preferred shares.

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 $164 million in 2014, $160 million in 2013 and $114 million in 2012. Estimated capital expenditures for 2015 are $183 million. Total capital expenditures for the five-year period 2015 through 2019 are estimated to be approximately $775 million, which includes $238 million at OTP for MISO-designated MVPs, $105 million for natural gas-fired generation to replace Hoot Lake Plant capacity, mostly in 2018 and 2019, and $53 million for the remainder of OTP’s share of the Big Stone Plant air quality control system (AQCS).

The breakdown of 2012, 2013 and 2014 actual cash used for capital expenditures and 2015 through 2019 estimated capital expenditures by segment is as follows:

(in millions)	2012	2013	2014	2015	2016	2017	2018	2019	Total for 2015-2019
Electric	$102	$150	$149	$151	$135	$95	$137	$147	$ 665
Manufacturing	9	7	11	29	13	17	24	13	96
Plastics	3	3	4	3	3	2	3	3	14
Corporate	--	--	--	--	--	--	--	--	--
Total	$114	$160	$164	$183	$151	$114	$164	$163	$ 775

The following table summarizes our contractual obligations at December 31, 2014 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)	$746	$ 50	$51	$46	$ 599
Debt Obligations	499	--	86	1	412
Interest on Debt Obligations	365	29	52	44	240
Capacity and Energy Requirements	344	34	45	47	218
Other Purchase Obligations	107	49	58	--	--
Postretirement Benefit Obligations	89	4	8	9	68
Operating Lease Obligations	37	7	10	6	14
Total Contractual Cash Obligations	$2,187	$ 173	$310	$153	$ 1,551

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 2015 through 2019 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.

On May 11, 2012 we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement.

On May 14, 2012, we entered into the Agreement with JPMS. Pursuant to the terms of the Agreement, we may offer and sell our common shares from time to time through JPMS, as our distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75 million. Under the Agreement, 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. In 2014 we received proceeds of $14,801,000 net of $535,000 paid to JPMS from the issuance of 519,636 shares under this program.

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2014 and December 31, 2013:

(in thousands)	Line Limit	In Use on December 31, 2014	Restricted due to Outstanding Letters of Credit	Available on December 31, 2014	Available on December 31, 2013
Otter Tail Corporation Credit Agreement	$ 150,000	$ 10,854	$ 274	$ 138,872	$ 149,341
OTP Credit Agreement	170,000	--	560	169,440	116,975
Total	$ 320,000	$ 10,854	$ 834	$ 308,312	$ 266,316

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2014 was $41,348,000 on October 16, 2014 and the average daily balance of debt outstanding during 2014 was $17,868,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2014 was 1.9% compared with 1.9% in 2013. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2014 was $97,000,000 on February 13, 2014 and the average daily balance of debt outstanding during 2014 was $12,815,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2014 was 1.4% compared with 1.4% in 2013. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2014 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 $150 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 November 3, 2014 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2018 to October 29, 2019. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations 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 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 November 3, 2014 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2018 to October 29, 2019. 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

Debt Retirements and Preferred Stock Redemption

On March 1, 2013 OTP entered into a Credit Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan) providing for a $40.9 million unsecured term loan (the Term Loan) to OTP originally due on June 1, 2014, which was fully drawn on March 1, 2013. The Loan Agreement was amended on October 29, 2013 to extend the due date on the Term Loan to January 15, 2015. Borrowings under the Loan Agreement bore interest at LIBOR plus 0.875%. On March 1, 2013 OTP utilized approximately $25.1 million of Term Loan proceeds to fund the redemption price for all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on that date, in each case for which OTP paid debt service. All such bonds had been called for redemption in full on March 1, 2013. Also on March 1, 2013, OTP utilized approximately $15.7 million of Term Loan proceeds to satisfy an intercompany note to us that had a balance and interest rate designed to equate to the balances and dividend rates of our cumulative preferred shares. Those cumulative preferred shares were redeemed on March 1, 2013 for $15.7 million, including $0.2 million in call premiums charged to equity and included with preferred dividends paid and as part of our preferred dividend requirement for the year ended December 31, 2013. On February 27, 2014 OTP used a portion of the proceeds from the issuance of notes under the 2013 Note Purchase Agreement (as defined below) to retire early the Term Loan.

On November 6 and 25, 2013 we purchased, in two separate transactions, $12,933,000 and $34,737,000, respectively, of our outstanding 9.000% notes due 2016 (the 2016 Notes), originally issued in the aggregate principal amount of $100 million. The purchased 2016 Notes (the Purchased 2016 Notes) were subsequently retired and are no longer outstanding. The remaining $52,330,000 principal amount of 2016 Notes outstanding, unless redeemed early or otherwise repaid, will mature and become due and payable on December 15, 2016. The price paid for the Purchased 2016 Notes was $59,404,000, which includes the principal amount of the Purchased 2016 Notes, plus accrued interest of $1,845,000 through the respective purchase dates and a negotiated premium of $9,889,000 (which is less than the premium we would have been required to pay to redeem them under the terms of the 2016 Notes). We used cash on hand to fund the purchase of the Purchased 2016 Notes. The amount of the debt retired as a result of these transactions is approximately equivalent to the remaining amount of debt that was associated with the operating companies that we have divested over the last two years. The retirement of the

Purchased Notes further strengthens our capital structure and reduces our pre-tax interest expense by approximately $4.3 million in both 2014 and 2015 and $4.1 million in 2016. On repayment, $363,000 in unamortized debt expense related to the 2016 Notes was immediately recognized as expense along with the $9,889,000 negotiated premium which, in total, reduced diluted earnings per share by $0.17 in 2013.

On July 13, 2012 we prepaid in full the Cascade Note issued pursuant to the Note Purchase Agreement dated as of February 23, 2007, as amended, between us and Cascade Investment L.L.C. (Cascade). Immediately before the prepayment, the Cascade Note bore interest at 8.89% annually. The price paid by us to prepay the Cascade Note was $63,031,000, which included the principal amount of the Cascade Note plus accrued interest of $531,000 and a negotiated prepayment premium of $12,500,000. We used the funds available under the Otter Tail Corporation Credit Agreement for the prepayment. This early retirement reflected our desire to lower our long-term debt outstanding given our recent divestitures. This retirement of debt strengthens our consolidated capital structure and will positively affect future years' earnings by lowering interest costs. On repayment, $606,000 in unamortized debt expense related to this note was immediately recognized as expense along with the $12,500,000 negotiated prepayment premium, which, in total, reduced diluted earnings per share by $0.22 in 2012.

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. OTP used a portion of the proceeds of the Notes to retire the Term Loan under the Loan Agreement with JPMorgan and to repay $82.5 million of short-term debt then outstanding under the OTP Credit Agreement. Remaining proceeds of the Notes were used to fund OTP 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 (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, 2014.

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, 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 provided in the Otter Tail Corporation Credit Agreement. As of December 31, 2014 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement was 3.96 to 1.00.

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, 2014 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 3.35 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, 2014 our interest-bearing debt to total capitalization was 0.47 to 1.00 on a consolidated basis and 0.50 to 1.00 for OTP.

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 3.3x for 2014 compared to 3.4x for 2013.

Our debt interest coverage ratio before taxes, calculated by dividing income before income taxes from continuing operation plus interest charges by interest charges plus capitalized interest, was 3.4x for 2014 compared to 3.1x for 2013. During 2015, we expect these coverage ratios to increase, assuming 2015 net income meets our expectations.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $6.1 million, but our line of credit borrowing limits are only restricted by $0.8 million of the 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.

2015 BUSINESS OUTLOOK

We anticipate 2015 diluted earnings per share to be in the range of $1.65 to $1.80. This guidance reflects the current mix of businesses owned by us, considers the cyclical nature of some of our businesses and reflects challenges, as well as our plans and strategies for improving future operating results. We expect capital expenditures for 2015 to be $183 million compared with $164 million in 2014. Major projects in our planned expenditures for 2015 include investments in several transmission projects for the Electric segment and the completion of the AQCS under construction at Big Stone Plant, all of which are expected to positively impact earnings and provide an immediate return on capital.

Segment components of our 2015 earnings per share guidance range are as follows:

	2014 EPS	2015 EPS Guidance	
	by Segment	Low	High
Electric	$ 1.19	$ 1.26	$ 1.29
Manufacturing	$ 0.25	$ 0.37	$ 0.41
Plastics	$ 0.33	$ 0.25	$ 0.29
Corporate	$ (0.22)	$ (0.23)	$ (0.19)
Total – Continuing Operations	$ 1.55	$ 1.65	$ 1.80

Contributing to our earnings guidance for 2015 are the following items:

We expect net income to increase in our Electric segment in 2015 compared with 2014 based on:

- o Rider recovery increases, including environmental riders in Minnesota, North Dakota and South Dakota related to the Big Stone AQCS environmental upgrades while under construction.
- o Expected increases in sales to pipeline and commercial customers.
- o A decrease in plant maintenance costs, as unanticipated maintenance issues encountered during the 2014 Hoot Lake shutdown are not expected to occur in 2015.

offset by:

- o An increase in pension costs as a result of an increase in projected benefit obligations based on a decrease in the discount rate from 5.30% to 4.35% and adoption of new mortality tables which have longer life expectancy assumptions.
- o Higher depreciation and property tax expense due to large transmission projects being put into service.
- o Higher short-term interest costs as major projects continue to be funded.

We expect 2015 net income from our Manufacturing segment to increase over 2014 due to:

- o An increase at BTD due to increases in volume as a result of expanded relationships with customers in recreational vehicle, lawn and garden, industrial and commercial end markets BTD serves, and the paint line expansion and insourcing of this service, offset by higher depreciation and general and administrative expenses.

- o An increase in earnings from T.O. Plastics mainly driven by expected increased sales in horticulture caused by growth in existing customers, new regions and new products. In addition, sales of custom products are projected to increase.
- o Backlog for the manufacturing companies of approximately $140 million for 2015 compared with $136 million one year ago.

We expect 2015 net income from our Plastics segment to be down from 2014. Sales volumes in 2015 are expected to be up slightly over 2014 with lower expected operating margins due to tighter spreads between raw material costs and sales prices, along with higher labor and freight costs.

Corporate costs are expected to be flat in 2015 compared with 2014.

The following table shows our 2014 capital expenditures and 2015 through 2019 anticipated capital expenditures and electric utility average rate base:

(in millions)	2014	2015	2016	2017	2018	2019
Capital Expenditures:						
Electric Segment:						
Transmission		$55	$90	$56	$58	$40
Environmental		56	3	--	--	--
Other		40	42	39	79	107
Total Electric Segment	$149	$151	$135	$95	$137	$147
Manufacturing and Plastics Segments	15	32	16	19	27	16
Total Capital Expenditures	$164	$183	$151	$114	$164	$163
Total Electric Utility Average Rate Base		$957	$1,017	$1,070	$1,118	$1,196

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 2015 through 2019 timeframe.

Our outlook for 2015 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, accrued renewable resource, transmission, and environmental cost recovery rider revenues, valuations of forward energy contracts, percentage-of-completion, warranty 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 2015 for our noncontributory funded pension plan is expected to be $7.1 million compared to $4.8 million in 2014, reflecting no change in the assumed rate of return on pension plan assets from 7.75% in 2014, and a decrease in the estimated discount rate used to determine annual benefit cost accruals from 5.30% in 2014 to 4.35% in 2015. 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 plans 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 2014, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2014 pension benefit cost by $688,000; a 0.25 decrease in the discount rate would have increased our 2014 pension benefit cost by $720,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2014 pension benefit cost by $494,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2014 pension benefit cost by $486,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2014 pension benefit cost by $540,000.

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 2014 postretirement medical benefit costs by $14,000. A 0.25 decrease in the discount rate would have increased our 2014 postretirement medical benefit costs by $14,000. 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.

REVENUE RECOGNITION
Our construction companies record revenues on a percentage-of-completion basis for fixed-price construction contracts. The operating results, assets and liabilities of our construction companies are reported under discontinued operations in the consolidated financial statements included in this report on Form 10-K. See note 16 to consolidated financial statements for additional information on discontinued operations. The method used to determine the progress of completion is based on the ratio of costs incurred to total estimated costs. The duration of the majority of these contracts ranges from less than a year up to three years. Revenues recognized on jobs in progress as of December 31, 2014 were $417 million. Any expected losses on jobs in progress at year-end 2014 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

We have a standard quarterly estimate at completion process in which we review the progress and performance of our contracts accounted for under percentage-of-completion accounting. As part of this process, our reviews include, but are not limited to, any outstanding key contract matters, progress towards completion and the related program schedule, identified risks and opportunities, and the related changes in estimates of revenues and costs. The risks and opportunities include our judgment about the ability and cost to achieve the schedule, technical requirements and other contract requirements. We must make assumptions regarding labor productivity and availability, the complexity of the work to be performed, the availability of materials, the length of time to complete the contract, and performance by subcontractors, among other variables. Based on this analysis, any adjustments to net sales, costs of sales, and the related impact to operating income are recorded as necessary in the period they become known. These adjustments may result from positive program performance and an increase in operating profit during the performance of individual contracts if we determine we will be successful in mitigating risks surrounding the technical, schedule, and cost aspects of those contracts or realizing related opportunities. Likewise, these adjustments may result in a decrease in operating profit if we determine we will not be successful in mitigating these risks or realizing related opportunities. Changes in estimates of net sales, costs of sales, and the related impact to operating income are recognized using a cumulative catch-up, which recognizes, in the current period, the cumulative effect of the changes on current and prior periods based on a contract's percent complete. A significant change in one or more of these estimates could affect the profitability of one or more of our contracts. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

OTP's forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under generally accepted accounting principles. Fair values for OTP's forward contracts for the purchases and sales of electricity at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models, and as such, are estimates. The forward energy purchase contracts that are marked to market as of December 31, 2014 are related to power purchase contracts where OTP intends to take or has taken physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts the costs incurred are subject to recovery in base rates and through fuel clause adjustments. Any derivative assets or liabilities and related gains or losses recorded as a result of the fair valuation of these power purchase contracts will not be realized and are 100% offset by regulatory liabilities and assets related to fuel clause adjustment treatment of purchased power costs. Therefore, the net impact of any recorded fair valuation gains or losses related to these contracts on the Company's consolidated net income is $0 and the net income impact of any future fair valuation adjustments of these contracts will be $0. When energy is delivered under these contracts, they will be settled at the original contract price and any fair valuation gains or losses and related derivative assets or liabilities recorded over the life of the contracts will be reversed along with any offsetting regulatory liabilities or assets.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Our operating companies encounter risks associated with sales and the collection of the associated accounts receivable. As such, they record provisions for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, the operating companies primarily utilize historical rates of accounts receivables written off as a percentage of total revenue. This historical rate is applied to the current revenues on a monthly basis. The historical rate is updated periodically based on events that may change the rate, such as a significant increase or decrease in collection performance and timing of payments as well as the calculated total exposure in relation to the allowance. Periodically, operating companies compare identified credit risks with allowances that have been established using historical experience and adjust allowances accordingly. In circumstances where an operating company is aware of a specific customer's inability to meet financial obligations, the operating company records a specific allowance for bad debts to reduce the account receivable to the amount it reasonably believes will be collected.

We believe the accounting estimates related to the allowance for doubtful accounts is critical because the underlying assumptions used for the allowance can change from period to period and could potentially cause a material impact to the income statement and working capital.

During 2014, for continuing operations, $0.8 million of bad debt expense (0.1% of total 2014 revenue of $799.3 million) was recorded and the allowance for doubtful accounts was $1.0 million (1.7% of gross trade accounts receivable) as of December 31, 2014. General economic conditions and specific geographic concerns are major factors that may affect the adequacy of the allowance and may result in a change in the annual bad debt expense. An increase or decrease in our consolidated allowance for doubtful accounts based on one percentage point of outstanding trade receivables at December 31, 2014 would result in a $0.6 million increase or decrease in bad debt expense.

Although an estimated allowance for doubtful accounts on our operating companies' accounts receivable is provided for, the allowance for doubtful accounts on the Electric segment's wholesale electric sales is insignificant in proportion to annual revenues from these sales. The Electric segment has not experienced a bad debt related to wholesale electric sales largely due to stringent risk management criteria related to these sales. Nonpayment on a single wholesale electric sale could result in a significant bad debt expense.

DEPRECIATION EXPENSE AND DEPRECIABLE LIVES

The provisions for depreciation of electric utility property for financial reporting purposes are made on the straight-line method based on the estimated service lives (5 to 70 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.89% in 2014, 2.96% in 2013 and 2.98% in 2012. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

Property and equipment of our nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting and are depreciated on a straight line basis over useful lives (3 to 40 years) of the related assets. We believe the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries in which our manufacturing and infrastructure companies operate or innovations in technology could result in a reduction of the estimated useful lives of our manufacturing and infrastructure operating companies' property, plant and equipment or in an impairment write-down of the carrying value of these properties.

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, 2014 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of ASC 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) 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.

In 2012, asset impairments were recorded at IMD, Shrco and OTESCO. The IMD and Shrco impairments were recorded in connection with their sales value and are reflected in the results of discontinued operations. As of December 31, 2014 an assessment of the carrying amounts of our remaining 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, 2014, 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.

In the fourth quarter of 2014 we entered into negotiations to sell our wholly owned subsidiary, Foley, a mechanical and prime contractor on industrial projects. As a result of an impairment indicator during the fourth quarter of 2014, we recorded a $5.6 million, or $0.15 per share, goodwill impairment charge. This impairment charge was based on the indicated offering price in a signed letter of intent for the purchase of Foley. The goodwill impairment loss is reflected in the results of discontinued operations and the remaining goodwill balance related to Foley is included in assets of discontinued operations. An assessment of the carrying amounts of the remaining goodwill of our reporting units reported under continuing operations as of December 31, 2014 indicated the fair values are substantially in excess of their respective book values and not impaired.

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 and intangible assets. 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, 2014 we had exposure to market risk associated with interest rates because we had $10.9 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.75% under our $150 million revolving credit facility.

All of our consolidated long-term debt outstanding on December 31, 2014 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.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power sales. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity sales. Specific limits are determined by a counterparty’s financial strength. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor’s), Baa3 (Moody’s) or BBB- (Fitch). OTP had no exposure at December 31, 2014 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

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, 2014 and 2013, 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, 2014. 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, 2014, 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
March 2, 2015

OTTER TAIL CORPORATION
Consolidated Balance Sheets, December 31

(in thousands)	2014	2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$--	$2,007
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $1,048 for 2014 and $1,148 for 2013)	60,172	57,828
Other	13,179	9,787
Inventories	85,203	72,627
Deferred Income Taxes	49,482	35,325
Unbilled Revenues	17,996	17,926
Regulatory Assets	25,273	17,940
Other	7,187	7,581
Assets of Discontinued Operations	48,657	49,478
Total Current Assets	307,149	270,499
Investments	8,582	9,362
Other Assets	30,111	28,834
Goodwill	31,488	31,488
Other Intangibles--Net	11,251	12,228
Deferred Debits		
Unamortized Debt Expense	4,300	4,188
Regulatory Assets	129,868	83,730
Total Deferred Debits	134,168	87,918
Plant		
Electric Plant in Service	1,545,112	1,460,884
Nonelectric Operations	175,159	170,925
Construction Work in Progress	248,677	187,462
Total Gross Plant	1,968,948	1,819,271
Less Accumulated Depreciation and Amortization	700,418	663,581
Net Plant	1,268,530	1,155,690
Total Assets	$1,791,279	$1,596,019

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION
Consolidated Balance Sheets, December 31

(in thousands, except share data)	2014	2013
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$10,854	$51,195
Current Maturities of Long-Term Debt	201	188
Accounts Payable	107,013	96,109
Accrued Salaries and Wages	19,256	18,957
Accrued Taxes	13,793	12,227
Derivative Liabilities	14,230	11,782
Other Accrued Liabilities	8,793	6,532
Liabilities of Discontinued Operations	27,559	39,283
Total Current Liabilities	201,699	236,273
Pensions Benefit Liability	102,711	69,743
Other Postretirement Benefits Liability	53,638	45,221
Other Noncurrent Liabilities	26,794	25,209
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	230,810	192,222
Deferred Tax Credits	26,384	28,288
Regulatory Liabilities	77,013	73,926
Other	975	718
Total Deferred Credits	335,182	295,154
Capitalization (page 69)		
Long-Term Debt, Net of Current Maturities	498,489	389,589
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, 2014—37,218,053 Shares; 2013—36,271,696 Shares	186,090	181,358
Premium on Common Shares	278,436	255,759
Retained Earnings	112,903	99,441
Accumulated Other Comprehensive Loss	(4,663)	(1,728)
Total Common Equity	572,766	534,830
Total Capitalization	1,071,255	924,419

Total Liabilities and Equity	$1,791,279	$1,596,019

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Statements of Income--For the Years Ended December 31

(in thousands, except per-share amounts)	2014	2013	2012
Operating Revenues			
Electric	$407,629	$373,462	$350,689
Product Sales	391,633	369,952	359,476
Total Operating Revenues	799,262	743,414	710,165
Operating Expenses			
Production Fuel - Electric	67,216	71,248	66,284
Purchased Power - Electric System Use	65,848	52,006	49,184
Electric Operation and Maintenance Expenses	141,936	133,395	121,069
Cost of Products Sold (depreciation included below)	308,069	283,267	270,045
Other Nonelectric Expenses	45,981	40,074	40,273
Asset Impairment Charge	--	--	432
Depreciation and Amortization	58,074	57 876	57,857
Property Taxes - Electric	12,607	11,311	10,720
Total Operating Expenses	699,731	649,177	615,864
Operating Income	99,531	94,237	94,301
Interest Charges	29,648	26,974	31,903
Loss on Early Retirement of Debt	--	10,252	13,106
Other Income	3,557	4,100	3,915
Income Before Income Taxes – Continuing Operations	73,440	61,111	53,207
Income Tax Expense – Continuing Operations	16,557	12,516	7,173
Net Income from Continuing Operations	56,883	48,595	46,034
Discontinued Operations			
Income (Loss) - net of Income Tax Expense of $3,952 in 2014, $1,036 in 2013 and $1,190 in 2012	6,445	2,060	(13,669)
Impairment Loss - net of Income Tax (Benefit) of $0 in 2014 and ($21,213) in 2012	(5,605)	--	(32,107)
Gain (Loss) on Disposition - net of Income Tax Expense of $6 in 2013 and $315 in 2012	--	210	(5,531)
Net Gain (Loss) from Discontinued Operations	840	2,270	(51,307)
Total Net Income (Loss)	57,723	50,865	(5,273)
Preferred Dividend Requirement and Other Adjustments	--	513	736
Earnings (Loss) Available for Common Shares	$57,723	$50,352	$(6,009)
Average Number of Common Shares Outstanding--Basic	36,514	36,151	36,048
Average Number of Common Shares Outstanding--Diluted	36,753	36,355	36,242
Basic Earnings (Loss) Per Common Share:			
Continuing Operations (net of preferred dividend requirement)	$1.56	$1.33	$1.25
Discontinued Operations	$0.02	$0.06	$(1.42)
	$1.58	$1.39	$(0.17)

Diluted Earnings (Loss) Per Common Share:			
Continuing Operations (net of preferred dividend requirement)	$1.55	$1.33	$1.25
Discontinued Operations	$0.02	$0.06	$(1.42)
	$1.57	$1.39	$(0.17)
Dividends Declared Per Common Share	$1.21	$1.19	$1.19

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION
Consolidated Statements of Comprehensive Income--For the Years Ended December 31

(in thousands)	2014	2013	2012
Net Income (Loss)	$57,723	$50,865	$(5,273)
Other Comprehensive Income (Loss):			
Unrealized (Loss) Gain on Available-for-Sale Securities:			
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	(19)	(27)	--
(Losses) Gains Arising During Period	(14)	(77)	154
Income Tax Benefit (Expense)	12	36	(53)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(21)	(68)	101
Pension and Postretirement Benefit Plans:			
Actuarial (Losses) Gains Net of Regulatory Allocation Adjustment	(5,048)	3,986	(2,133)
Amortization of Unrecognized Postretirement Benefit Costs (note 11)	192	555	376
Income Tax Benefit (Expense)	1,942	(1,816)	703
Pension and Postretirement Benefit Plans – net-of-tax	(2,914)	2,725	(1,054)
Total Other Comprehensive (Loss) Income	(2,935)	2,657	(953)
Total Comprehensive Income (Loss)	$54,788	$53,522	$(6,226)

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
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, 2011	36,101,695	$ 180,509	$ 253,123	$ 141,248	$ (3,432) (a)	$ 571,448
Common Stock Issuances, Net of Expenses	71,745	359	148			507
Common Stock Retirements	(5,072)	(26)	(85)			(111)
Net Loss				(5,273)		(5,273)
Other Comprehensive Loss					(953)	(953)
Tax Benefit – Stock Compensation			(103)			(103)
Employee Stock Incentive Plan Expense			435			435
Premium on Purchase of Stock for Employee Purchase Plan			(222)			(222)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends ($1.19 per share)				(43,018)		(43,018)
Balance, December 31, 2012	36,168,368	$ 180,842	$ 253,296	$ 92,221	$ (4,385) (a)	$ 521,974
Common Stock Issuances, Net of Expenses	112,512	562	2,095			2,657
Common Stock Retirements	(9,184)	(46)	(177)			(223)
Net Income				50,865		50,865
Other Comprehensive Income					2,657	2,657
Tax Benefit – Stock Compensation			299			299
Employee Stock Incentive Plan Expense			418			418
Premium on Purchase of Stock for Employee Purchase Plan			(258)			(258)
Cumulative Preferred Dividends				(427)		(427)
Preferred Stock Issuance Expenses Transferred to Retained Earnings on Redemption of Preferred Shares			86	(86)		--
Common Dividends ($1.19 per share)				(43,132)		(43,132)
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 Income					(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

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

(in thousands)	2014	2013	2012
Unrealized Gain on Marketable Equity Securities:			
Before Tax	$40	$73	$177
Tax Effect	(14)	(26)	(62)
Unrealized Gain on Marketable Equity Securities – Net-of-Tax	26	47	115
Unamortized Actuarial Losses, Prior Service Costs and Transition Obligation Related to Pension and Postretirement Benefits:			
Before Tax	(7,815)	(2,959)	(7,500)
Tax Effect	3,126	1,184	3,000
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits – Net-of-Tax	(4,689)	(1,775)	(4,500)
Accumulated Other Comprehensive Loss:			
Before Tax	(7,775)	(2,886)	(7,323)
Tax Effect	3,112	1,158	2,938
Net Accumulated Other Comprehensive Loss	$(4,663)	$(1,728)	$(4,385)

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Statements of Cash Flows—For the Years Ended December 31

(in thousands)	2014	2013	2012
Cash Flows from Operating Activities			
Net Income (Loss)	$57,723	$50,865	$(5,273)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Net (Gain) Loss from Sale of Discontinued Operations	--	(210)	5,531
Net (Income) Loss from Discontinued Operations	(840)	(2,060)	45,776
Depreciation and Amortization	58,074	57,876	57,857
Asset Impairment Charge	--	--	432
Premium Paid for Early Retirement of Long-Term Debt	--	9,889	12,500
Deferred Tax Credits	(1,904)	(1,925)	(2,091)
Deferred Income Taxes	28,204	15,333	11,755
Change in Deferred Debits and Other Assets	(50,361)	56,720	(4,654)
Discretionary Contribution to Pension Fund	(20,000)	(10,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	58,442	(42,226)	32,718
Allowance for Equity/Other Funds Used During Construction	(1,543)	(1,823)	(1,168)
Change in Derivatives Net of Regulatory Deferral	519	8	718
Stock Compensation Expense – Equity Awards	1,783	1,456	1,311
Other—Net	601	1,222	5,666
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	(4,647)	4,033	(4,041)
Change in Inventories	(12,577)	(3,371)	(675)
Change in Other Current Assets	(579)	(3,911)	(1,324)
Change in Payables and Other Current Liabilities	10,296	11,045	26,134
Change in Interest Payable and Income Taxes Receivable/Payable	2,578	(513)	(16,146)
Net Cash Provided by Continuing Operations	125,769	142,408	155,026
Net Cash (Used in) Provided by Discontinued Operations	(13,295)	5,373	78,521
Net Cash Provided by Operating Activities	112,474	147,781	233,547
Cash Flows from Investing Activities			
Capital Expenditures	(163,582)	(159,833)	(114,186)
Proceeds from Disposal of Noncurrent Assets	2,467	2,196	2,832
Net Increase in Other Investments	(2,785)	(1,845)	(1,184)
Net Cash Used in Investing Activities - Continuing Operations	(163,900)	(159,482)	(112,538)
Net Proceeds from Sale of Discontinued Operations	--	12,842	42,229
Net Cash Used in Investing Activities - Discontinued Operations	(596)	(2,557)	(13,268)
Net Cash Used in Investing Activities	(164,496)	(149,197)	(83,577)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	1,236	--	--
Net Short-Term (Repayments) Borrowings	(40,341)	51,195	--
Proceeds from Issuance of Common Stock	26,259	1,821	--
Common Stock Issuance Expenses	(673)	(3)	(370)
Payments for Retirement of Capital Stock	(590)	(15,723)	(111)
Proceeds from Issuance of Long-Term Debt	150,000	40,900	--
Short-Term and Long-Term Debt Issuance Expenses	(856)	(522)	(897)
Payments for Retirement of Long-Term Debt	(41,088)	(72,981)	(50,224)

Premium Paid for Early Retirement of Long-Term Debt	--	(9,889)	(12,500)
Dividends Paid and Other Distributions	(44,261)	(43,818)	(43,976)
Net Cash Provided by (Used in) Financing Activities - Continuing Operations	49,686	(49,020)	(108,078)
Net Cash Provided by (Used in) Financing Activities - Discontinued Operations	1,178	--	(4,278)
Net Cash Provided by (Used in) Financing Activities	50,864	(49,020)	(112,356)
Net Change in Cash and Cash Equivalents - Discontinued Operations	(849)	(2,306)	(1,033)
Net Change in Cash and Cash Equivalents	(2,007)	(52,742)	36,581
Cash and Cash Equivalents at Beginning of Period	2,007	54,749	18,168
Cash and Cash Equivalents at End of Period	$--	$2,007	$54,749

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION
Consolidated Statements of Capitalization, December 31

(in thousands, except share data)	2014	2013
Short-Term Debt		
Otter Tail Corporation Credit Agreement	$10,854	$--
Otter Tail Power Company Credit Agreement	--	51,195
Total Short-Term Debt	$10,854	$51,195
Long-Term Debt		
Obligations of Otter Tail Corporation		
9.000% Notes, due December 15, 2016	$52,330	$52,330
North Dakota Development Note, 3.95%, due April 1, 2018	256	325
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	1,105	1,223
Total – Otter Tail Corporation	53,691	53,878
Obligations of Otter Tail Power Company		
Unsecured Term Loan - LIBOR plus 0.875%, due January 15, 2015 (early retired on February 27, 2014)	--	40,900
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	--
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	--
Total – Otter Tail Power Company	445,000	335,900
Total	498,691	389,778
Less:		
Current Maturities – Otter Tail Corporation	201	188
Unamortized Debt Discount – Otter Tail Corporation	1	1
Total Long-Term Debt	498,489	389,589
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	572,766	534,830
Total Capitalization	$1,071,255	$924,419

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Notes to Consolidated Financial Statements
For the years ended December 31, 2014, 2013 and 2012

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 $689,000 in 2014, $1,002,000 in 2013 and $656,000 in 2012. 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 service lives of the properties (5 to 70 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.89% in 2014, 2.96% in 2013 and 2.98% in 2012. 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 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 2014, 2013 or 2012. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

Jointly Owned Facilities
The consolidated balance sheets include OTP's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the Company's December 31, 2014 and 2013 consolidated balance sheets:

(in thousands)	2014	2013
Big Stone Plant:		
Electric Plant in Service	$143,746	$142,780
Construction Work in Progress	160,809	94,913
Accumulated Depreciation	(86,211)	(83,005)
Net Plant	$218,344	$154,688
Coyote Station:		
Electric Plant in Service	$163,824	$162,095
Construction Work in Progress	1,725	303
Accumulated Depreciation	(99,364)	(96,907)
Net Plant	$66,185	$65,491

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OTP is a joint owner, with other regional utilities, in three major transmission lines and two additional major planned transmission line projects with the following ownership interests: 14.8% in the Bemidji-Grand Rapids 230 kV line, approximately 14.1% in the Fargo-Monticello 345 kV line, approximately 4.8% in the Brookings-Southeast Twin Cities Multi-Value Project (MVP) 345 kV line, 50.0% in the Big Stone South to Brookings MVP 345 kV line and 50.0% in the Big Stone South to Ellendale MVP 345 kV line. The following amounts for the jointly-owned transmission facilities are included in the Company's December 31, 2014 and 2013 consolidated balance sheets:

(in thousands)	2014	2013
Electric Plant in Service	$68,648	$26,337
Construction Work in Progress	59,163	71,205
Accumulated Depreciation	(1,758)	(837)
Net Plant	$126,053	$96,705

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 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 to be paid by the Coyote Station owners under the LSA will reflect the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining lignite 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.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commences with the first delivery of coal to Coyote Station, scheduled for May 2016, by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through December 31, 2014 is $21.6 million. 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, 2014 could be as high as $21.6 million.

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.

In June 2012, the Company entered into a nonbinding letter of interest with Trinity Industries, Inc. (Trinity) to sell the fixed assets of IMD for $20 million, with the Company retaining IMD’s net working capital—approximately $66 million on June 30, 2012. On September 6, 2012 the Company entered into definitive agreements with Trinity to sell the fixed assets of IMD for $20 million. The agreed on price for the fixed assets was an indicator of the fair value of the assets under level 2 of the ASC fair value hierarchy and an indication of a decrease in the market value of the assets being sold, which were significantly impacted by a decline in market conditions in the wind energy industry. IMD had no tower orders for 2013 due to the expected expiration, at the end of 2012, of the Federal Production Tax Credit (PTC) for investments in renewable energy resources. These factors resulted in IMD recording a fair value adjustment of its long-lived assets to the indicated market price of $20 million and an asset impairment charge of $45.6 million ($27.5 million net-of-tax benefits), or $0.76 per share, in June 2012 broken down as follows:

(in thousands)	
Long-Lived Assets (net of accumulated depreciation)	$45,285
Goodwill	288
Total Asset Impairment Charges	$45,573

The sales of IMD's fixed assets were completed in 2012 with the effects of the related transactions reflected in discontinued operations in the Company's 2012 consolidated financial statements. See note 16 to consolidated financial statements for further information.

Otter Tail Energy Services Company (OTESCO) recorded an asset impairment charge of $0.4 million in 2012 related to wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota based on the fair value of these assets declining to $0 as of March 31, 2012.

On February 8, 2013 the Company sold substantially all of the assets of Shrco, Inc. (Shrco), the Company's former waterfront equipment manufacturer, subject to certain closing conditions. The Company recorded a $7.7 million ($4.6 million net-of-tax benefits), or $0.13 per share, asset impairment charge in December 2012 based on the indicated market value of Shrco's assets broken down as follows:

(in thousands)	
Long-Lived Assets (net of accumulated depreciation)	$5,859
Inventory	782
Accrued Selling Costs	1,106
Total Impairment Charges	$7,747

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 and warranty costs 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 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, are 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.

OTP's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on the Company's consolidated statement of income. Under ASC 815, OTP's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. See note 5 to consolidated financial statements for further discussion.

Manufacturing operating revenues are recorded when products are shipped.

The Company's construction companies, reported under discontinued operations in the accompanying financial statements, enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The method used to determine the progress of completion is based on the ratio of costs incurred to total estimated costs on construction projects. See note 16 to consolidated financial statements.

The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2014	December 31, 2013
Costs Incurred on Uncompleted Contracts	$402,332	$361,487
Less Billings to Date	(411,909)	(377,608)
Plus Estimated Earnings Recognized	15,154	6,477
Net Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	$5,577	$(9,644)

The following costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings are included in the Company's consolidated balance sheets under assets of discontinued operations and liabilities of discontinued operations:

(in thousands)	December 31, 2014	December 31, 2013
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 8,133	$ 4,063
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(2,556)	(13,707)
Net Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	$ 5,577	$ (9,644)

The Company has a standard quarterly estimate at completion process in which management reviews the progress and performance of the Company's contracts accounted for under percentage-of-completion accounting. As part of this process, management reviews include, but are not limited to, any outstanding key contract matters, progress towards completion and the related program schedule, identified risks and opportunities, and the related changes in estimates of revenues and costs. The risks and opportunities include management's judgment about the ability and cost to achieve the schedule, technical requirements and other contract requirements. Management must make assumptions regarding labor productivity and availability, the complexity of the work to be performed, the availability of materials, the length of time to complete the contract, and performance by subcontractors, among other variables. Based on this analysis, any adjustments to net sales, costs of sales, and the related impact to operating income are recorded as necessary in the period they become known. These adjustments may result from positive program performance and an increase in operating profit during the performance of individual contracts if management determines it will be successful in mitigating risks surrounding the technical, schedule, and cost aspects of those contracts or realizing related opportunities. Likewise, these adjustments may result in a decrease in operating profit if management determines it will not be successful in mitigating these risks or realizing related opportunities. Changes in estimates of net sales, costs of sales, and the related impact to operating income are recognized using a cumulative catch-up, which recognizes, in the current period, the cumulative effect of the changes on current and prior periods based on a contract's percent complete. A significant change in one or more of these estimates could affect the profitability of one or more of the Company's contracts. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

In 2012, Foley Company (Foley) experienced cost overruns in excess of estimated costs on several large projects. All of these projects were substantially completed as of December 31, 2012. Estimated costs on certain projects in excess of previous period estimates resulted in insignificant pretax charges in 2014 compared with $0.6 million in 2013 and $14.9 million in 2012.

Plastics operating revenues are recorded when the product is shipped.

Warranty Reserves
The Company establishes reserves for estimated product warranty costs at the time revenue is recognized based on historical warranty experience and additionally for any known product warranty issues. Certain products previously sold by the Company carried one to fifteen year warranties. Although the Company engaged in extensive product quality programs and processes, the Company’s warranty obligations have been and may in the future be affected by product failure rates, repair or field replacement costs and additional development costs incurred in correcting product failures. The warranty reserve balances as of December 31, 2014 and December 31, 2013 relate entirely to products that were produced by IMD and Shrco prior to the Company selling the assets of these companies and are included in liabilities of discontinued operations. See note 16 to consolidated financial statements.

Retainage
Assets of discontinued operations include the following amounts billed under contracts by the Company’s construction subsidiaries that have been retained by customers pending project completion:

(in thousands)	December 31, 2014	December 31, 2013
Accounts Receivable Retained by Customers	$ 6,759	$ 7,125

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. 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, accrued renewable resource, transmission and environmental cost recovery rider revenues, valuations of forward energy contracts, percentage-of-completion, warranty reserves and actuarially determined benefits costs and liabilities. 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, 2014 and 2013:

(in thousands)	December 31, 2014	December 31, 2013
Cost Method:		
Economic Development Loan Pools	$ 174	$ 219
Other	129	158
Equity Method - Affordable Housing and Other Partnerships	265	43
Marketable Securities Classified as Available-for-Sale	8,014	8,942
Total Investments	$ 8,582	$ 9,362

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, 2014. See further discussion below.

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, 2014 and December 31, 2013:

December 31, 2014 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$257
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	120		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		6,761	
U.S. Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		1,253	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	593		
Total Assets	$713	$8,014	$257
Liabilities:			
Derivative Liabilities - Forward Gasoline Purchase Contracts	$--	$342	$--
Derivative Liabilities - Forward Energy Contracts	--	--	13,888
Total Liabilities	$--	$342	$13,888

December 31, 2013 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$338

Forward Gasoline Purchase Contracts		62	
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,671	
U.S. Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		1,271	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	866		
Total Assets	$976	$9,004	$338
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$103	$11,679
Total Liabilities	$--	$103	$11,679

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

Forward Energy Contracts – Prices used for the fair valuation of these forward purchases and sales of electricity, which have illiquid trading points, are indexed to a price at an active market.

Forward Gasoline Purchase Contracts – These contracts are 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.

Corporate and U.S. Government-Sponsored Enterprises' 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.

Fair values for OTP's forward energy contracts with delivery points that are not at an active trading hub included in Level 3 of the fair value hierarchy in the table above as of December 31, 2014 and December 31, 2013, are based on prices indexed to observable prices at an active trading hub. Prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The December 31, 2014 Level 3 forward electric basis spreads ranged from $2.50 to $7.97 per megawatt-hour under the active trading hub price. The weighted average price was $34.95 per megawatt-hour.

In the table above, the fair value of the Level 3 forward energy contracts in derivative asset and derivative liability positions as of December 31, 2014 are related to power purchase contracts where OTP intends to take or has taken physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts the costs incurred are subject to recovery in base rates and through fuel clause adjustments. Any derivative assets or liabilities and related gains or losses recorded as a result of the fair valuation of these power purchase contracts will not be realized and are 100% offset by regulatory liabilities and assets related to fuel clause adjustment treatment of purchased power costs. Therefore, the net impact of any recorded fair valuation gains or losses related to these contracts on the Company's consolidated net income is $0 and the net income impact of any future fair valuation adjustments of these contracts will be $0. When energy is delivered under these contracts, they will be settled at the original contract price and any fair valuation gains or losses and related derivative assets or liabilities recorded over the life of the contracts will be reversed along with any offsetting regulatory liabilities or assets. Because of regulatory accounting treatment, any price volatility related to the fair valuation of these contracts had no impact on the Company's reported consolidated net income for the years ended December 31, 2014 and 2013.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the twelve-month periods ended December 31, 2014 and 2013:

(in thousands)	2014	2013
Forward Energy Contracts - Fair Values Beginning of Period	$(11,341)	$(17,782)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	2,785	7,943
Changes in Fair Value of Contracts Entered into in Prior Periods	166	(640)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(8,390)	(10,479)
Net Decrease in Value of Open Contracts Entered into in Current Period	(5,241)	(862)
Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	$(13,631)	$(11,341)

Inventories

The Electric segment inventories are reported at average cost. All other segments' inventories are stated at the lower of cost (first in, first out) or market. Inventories consist of the following:

(in thousands)	December 31, 2014	December 31, 2013
Finished Goods	$ 27,998	$ 20,649
Work in Process	10,628	9,942
Raw Material, Fuel and Supplies	46,577	42,036
Total Inventories	$ 85,203	$ 72,627

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 and indefinite-lived intangible assets 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 2012 the Company sold Moorhead Electric, Inc. (MEI), a subsidiary company that provided electrical contracting services. In connection with this sale, the Company disposed of $147,000 in goodwill associated with the purchase of MEI in 1992. With the classification of Aevenia in discontinued operations in 2014, the 2012 results of operations and cash flows of MEI are now reflected in discontinued operations.

In the fourth quarter of 2014 the Company entered into negotiations to sell its wholly owned subsidiary, Foley, a mechanical and prime contractor on industrial projects. As a result of an impairment indicator during the fourth quarter of 2014, the Company recorded a $5.6 million, or $0.15 per share, goodwill impairment charge. This impairment charge was based on the indicated offering price in a signed letter of intent for the purchase of Foley. The goodwill impairment loss is reflected in the results of discontinued operations and the remaining goodwill balance related to Foley is included in assets of discontinued operations. An assessment of the carrying amounts of the remaining goodwill of the Company's reporting units reported under continuing operations as of December 31, 2014 indicated the fair values are substantially in excess of their respective book values and not impaired.

The following tables summarize changes to goodwill by business segment during 2014 and 2013:

(in thousands)	Gross Balance December 31, 2013	Accumulated Impairments	Balance (net of impairments) December 31, 2013	Adjustments to Goodwill in 2014	Balance (net of impairments) December 31, 2014
Manufacturing	$ 12,186	$ --	$ 12,186	$ --	$ 12,186
Plastics	19,302	--	19,302	--	19,302
Total	$ 31,488	$ --	$ 31,488	$ --	$ 31,488

(in thousands)	Gross Balance December 31, 2012	Accumulated Impairments	Balance (net of impairments) December 31, 2012	Adjustments to Goodwill in 2013	Balance (net of impairments) December 31, 2013
Manufacturing	$ 12,186	$ --	$ 12,186	$ --	$ 12,186
Plastics	19,302	--	19,302	--	19,302
Total	$ 31,488	$ --	$ 31,488	$ --	$ 31,488

Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC 360 10 35, Property, Plant, and Equipment—Overall—Subsequent Measurement. The following table summarizes the components of the Company's intangible assets at December 31:

2014 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods

Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 5,784	$ 11,027	60-160 months
Other Intangible Assets Including Contracts	639	415	224	21 months
Total	$ 17,450	$ 6,199	$ 11,251	

2013 (in thousands)				
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 4,935	$ 11,876	72-172 months
Other Intangible Assets Including Contracts	772	420	352	33 months
Total	$ 17,583	$ 5,355	$ 12,228	

The amortization expense for these intangible assets was:

(in thousands)	2014	2013	2012
Amortization Expense – Intangible Assets	$977	$977	$981

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

(in thousands)	2015	2016	2017	2018	2019
Estimated Amortization Expense – Intangible Assets	$977	$945	$849	$849	$849

Supplemental Disclosures of Cash Flow Information

	As of December 31,	
(in thousands)	2014	2013
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions[1]	$24,526	$22,951
Accounts Receivable Outstanding Related to Joint Plant Owner's Share of Capital Additions[2]	$4,594	$3,264

[1]Amounts are included in cash used for capital expenditures in subsequent periods when payables are settled.
[2]Amounts are deducted from cash used for capital expenditures in subsequent periods when cash is received.

(in thousands)	2014	2013	2012
Cash Paid (Received) During the Year for:			
Interest (net of amount capitalized)	$26,364	$26,789	$30,741
Income Taxes	$145	$(453)	$(353)

New Accounting Standards

Accounting Standards Update (ASU) 2013-11
In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) (ASC 740), Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, which requires an entity with unrecognized tax benefits to present the unrecognized tax benefits as a reduction to a deferred tax asset related to a net operating loss carryforward, a similar tax loss, or a tax credit carryforward when such net operating loss carryforward, similar tax loss, or tax credit carryforward is available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position. The ASU 2013-11 amendments to ASC 740 are effective for fiscal years beginning after December 15, 2013. The Company adopted the reporting requirements in ASU 2013-11 in the first quarter of 2014 on a prospective basis and transferred $4.3 million of unrecognized tax benefits from other long-term liabilities to long-term deferred income taxes.

ASU 2014-09
In May 2014, the FASB issued ASU 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.

ASU 2014-09 amendments to the ASC are effective for fiscal years beginning after December 15, 2016. 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. Early application of the ASU amendments is not permitted. The Company is currently reviewing ASU 2014-09, identifying key impacts to its businesses, reviewing revenue streams and contracts to determine areas where the amendments in

ASU 2014-09 will be applicable and evaluating transition options.

2. Business Combinations, Dispositions and Segment Information

The Company acquired no new businesses in 2014, 2013 or 2012.

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 2013 and 2012, and was in the process of negotiating the sales of Foley, its mechanical and prime contractor on industrial projects, and Aevenia, Inc. (Aevenia), its electrical design and construction services company, on December 31, 2014, which resulted in the removal of its Construction segment from continuing operations. The sale of substantially all of Shrco’s assets closed on February 8, 2013. On November 30, 2012 the Company completed the sale of the fixed assets of IMD, eliminating its Wind Energy segment. On February 29, 2012 the Company completed the sale of DMS Health Technologies, Inc. (DMS), its health services company, eliminating its Health Services segment. On January 18, 2012 the Company sold the assets of Aviva Sports, Inc. (Aviva), a wholly owned subsidiary of Shrco that sold various recreational products.

The results of operations of Shrco including Aviva, IMD, DMS, Wylie, Foley and Aevenia are reported as discontinued operations in the Company’s consolidated financial statements as of and for the years ended December 31, 2014, 2013 and 2012, 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 includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is an active wholesale participant in the Midcontinent Independent System Operator, Inc. (MISO) markets. OTP’s operations have been the Company’s primary business since 1907. Prior to 2013, the Electric segment included OTESCO, which provided technical and engineering services. OTESCO ceased operations and did not record any operating revenues, expenses or net income in 2013 or 2014.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping and fabrication, and production of material and handling trays, horticultural containers and produce packaging. These businesses have manufacturing facilities in 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 2014, 2013 or 2012. All of the Company's long-lived assets are within the United States.

Percent of Sales Revenue by Country for the Year Ended December 31:	2014	2013	2012
United States of America	95.9%	97.2%	97.3%
Mexico	3.0 %	1.7 %	1.3 %
Canada	0.9 %	1.0 %	1.4 %
All Other Countries (none greater than 0.05%)	0.2 %	0.1 %	0.0 %

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for 2014, 2013 and 2012 is presented in the following table:

(in thousands)	2014	2013	2012
Operating Revenue			
Electric	$407,743	$373,540	$350,765
Manufacturing	219,583	204,997	208,965
Plastics	172,050	164,957	150,517
Intersegment Eliminations	(114)	(80)	(82)
Total	$799,262	$743,414	$710,165
Cost of Products Sold			
Manufacturing	$169,033	$154,235	$157,437
Plastics	139,081	129,042	112,662
Intersegment Eliminations	(45)	(10)	(54)
Total	$308,069	$283,267	$270,045
Other Nonelectric Expenses			
Manufacturing	$23,340	$18,820	$18,233
Plastics	9,292	8,571	8,784
Corporate	13,418	12,753	13,284
Intersegment Eliminations	(69)	(70)	(28)
Total	$45,981	$40,074	$40,273
Depreciation and Amortization			
Electric	$44,076	$43,125	$42,051
Manufacturing	10,518	11,194	12,208
Plastics	3,364	3,350	3,118
Corporate	116	207	480
Total	$58,074	$57,876	$57,857
Operating Income (Loss)			
Electric	$76,060	$62,455	$61,025
Manufacturing	16,692	20,748	21,087
Plastics	20,313	23,994	25,953
Corporate	(13,534)	(12,960)	(13,764)
Total	$99,531	$94,237	$94,301
Interest Charges			
Electric	$23,322	$17,461	$19,049
Manufacturing	3,243	3,255	3,557
Plastics	1,043	1,001	2,519
Corporate and Intersegment Eliminations	2,040	5,257	6,778

Total	$29,648	$26,974	$31,903

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(in thousands)	2014	2013	2012
Income Tax Expense (Benefit) – Continuing Operations			
Electric	$11,029	$9,278	$5,862
Manufacturing	4,117	6,047	6,954
Plastics	7,301	9,249	9,393
Corporate	(5,890)	(12,058)	(15,036)
Total	$16,557	$12,516	$7,173
Earnings (Loss) Available for Common Shares			
Electric	$43,684	$38,236	$38,341
Manufacturing	9,361	11,457	10,676
Plastics	12,085	13,809	14,113
Corporate	(8,247)	(15,420)	(17,832)
Discontinued Operations	840	2,270	(51,307)
Total	$57,723	$50,352	$(6,009)
Capital Expenditures			
Electric	$148,719	$149,467	$101,919
Manufacturing	11,252	7,046	9,311
Plastics	3,567	3,273	2,819
Corporate	44	47	137
Total	$163,582	$159,833	$114,186
Identifiable Assets			
Electric	$1,472,647	$1,290,416	$1,226,145
Manufacturing	130,701	119,302	114,933
Plastics	87,356	76,853	78,855
Corporate	51,918	59,970	112,616
Assets of Discontinued Operations	48,657	49,478	69,788
Total	$1,791,279	$1,596,019	$1,602,337

3. Rate and Regulatory Matters

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 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 2014, 2013 or 2012.

Major Capital Expenditure Projects

The Big Stone South – Brookings Project—This is a planned 345 kiloVolt (kV) transmission line that will extend approximately 70 miles between a proposed substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Xcel Energy jointly developed this project. MISO approved this project as an 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 that the costs of transmission projects with regional benefits are properly assigned to those who benefit. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. The SDPUC approved the certification for the northern portion of the route on April 9, 2013 and granted approval of a route permit for the southern portion of the line on February 18, 2014. On August 1, 2014 OTP and Xcel Energy entered into agreements to construct the project. This line is expected to be in service in 2017.

The Big Stone South – Ellendale Project—This is a proposed 345 kV transmission line that will extend 160 to 170 miles between a proposed substation near Big Stone City, South Dakota and a proposed substation near Ellendale, North Dakota. OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. On August 25, 2013 the NDPSC granted Certificates of Public Convenience and Necessity to OTP and MDU for ten miles of the proposed line to be built in North Dakota. On July 10, 2014 the NDPSC approved a Certificate of Corridor Compatibility and a route permit for the North Dakota section of the proposed line. On August 22, 2014 the SDPUC issued an order approving the route permit for the South Dakota section of the proposed line. If the proposed project receives all the necessary approvals, OTP anticipates the line will 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. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo–Monticello 345 kV Project (the Fargo Project), (2) the Brookings–Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji–Grand Rapids 230 kV Project (the Bemidji Project), and (4) the Twin Cities–LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project. Recovery of OTP's CapX2020 transmission investments is through the MISO Tariff (the Brookings Project as an MVP) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

The Fargo Project—The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. The St. Cloud to Alexandria portion of the Fargo Project was placed into service on April 23, 2014. Construction is underway for the remaining portion of the project, which is expected to be in service in 2015.

The Brookings Project—The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. The first phase of the 250 mile Brookings Project was energized in March 2014. Additional segments of the line were energized in April 2014. The entire project is expected to be in service in 2015.

The Bemidji Project—The Bemidji-Grand Rapids transmission line was fully energized and put into service on September 17, 2012.

Big Stone Plant Air Quality Control System (AQCS)—The South Dakota Department of Environment and Natural Resources determined that the Big Stone Plant is subject to Best-Available Retrofit Technology (BART) requirements of the Clean Air Act, based on air dispersion modeling indicating that Big Stone Plant's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan.

OTP is currently in the process of constructing the BART-compliant AQCS at Big Stone Plant for a current projected cost of approximately $384 million (OTP's 53.9% share would be $207 million) with an expected commercial operation date of October 2015. OTP's share of AQCS construction expenditures incurred through December 31, 2014 is $153 million, excluding Allowance for Funds Used During Construction (AFUDC).

Big Stone II Project—On June 30, 2005 OTP and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project's lead developer—from Big Stone II. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project. OTP requested jurisdictional recovery in

Minnesota, North Dakota and South Dakota of amounts it had invested in the Big Stone II project at the time of its withdrawal, discussed below under the respective jurisdictional sections of this report.

Minnesota

2010 General Rate Case— OTP's most recent 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. The MPUC's written order included: (1) recovery of Big Stone II costs over five years, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment. 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%.

Renewable Energy Standards, Conservation, Renewable Resource Riders— 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. OTP is currently evaluating potential options for meeting that standard. 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 comply with Minnesota renewable energy standards. 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.

The costs for three major wind farms previously approved by the MPUC for recovery through OTP’s Minnesota Renewable Resource Adjustment (MNRRA) were moved to base rates as of October 1, 2011 under the MPUC’s April 25, 2011 general rate case order with the exception of the remaining balance of the MNRRA regulatory asset. OTP continued to collect the remaining regulatory asset balance through April 30, 2013, when the balance was near zero. On April 4, 2013 the MPUC authorized that any remaining unrecovered balance be retained as a regulatory asset to be recovered in OTP’s next general rate case. Effective May 1, 2013 the resource adjustment on OTP’s Minnesota customers’ bills no longer includes MNRRA costs.

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 Minnesota Department of Commerce (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 January 11, 2012 the MPUC approved the recovery of $3.5 million for 2010 MNCIP financial incentives. Beginning in January 2012, OTP’s MNCIP Conservation Cost Recovery Adjustment increased from 3.0% to 3.8% for all Minnesota retail electric customers. On March 30, 2012 OTP recognized an additional $0.4 million of incentive related to 2011 and submitted its annual 2011 financial incentive filing request for $2.6 million. In December 2012, the MPUC approved the recovery of $2.6 million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer’s bill to an amount per kwh consumed. On January 1, 2013 OTP’s MNCIP surcharge decreased from 3.8% of the customer’s bill to $0.00142 per kwh, which equates to approximately 1.9% of a customer’s bill. OTP recognized $2.6 million of MNCIP financial incentives in 2012 and an additional $0.1 million in 2013 relating to 2012 program results. On October 10, 2013 the MPUC approved OTP's 2012 financial incentive request for $2.7 million as well as its request for an updated surcharge rate to be implemented on November 1, 2013. OTP recognized $3.9 million in MNCIP financial incentives in 2013 related to the results of its conservation improvement programs in Minnesota in 2013. On April 1, 2014 OTP submitted its annual 2013 financial incentive filing request for $4.0 million along with a request for an updated surcharge rate. 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. Based on preliminary results from the 2014 MNCIP program year, OTP is estimating a financial incentive for 2014 of $2.5 million. OTP is estimating a lower incentive for 2014 in response 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. Also, OTP estimates it saved approximately 3 million less kwhs in 2014 compared with 2013. OTP will request approval from the MPUC in an April 1, 2015 filing.

OTP had a regulatory asset of $8.2 million for allowable costs and financial incentives eligible for recovery through the MNCIP rider that had not been billed to Minnesota customers as of December 31, 2014. OTP's Minnesota conservation recoverable costs and incentives totaled $7.8 million in 2014, $9.3 million in 2013 and $7.8 million in 2012.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act (the Act) provides a similar 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 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. 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. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers. On March 26, 2012 the MPUC approved an update to OTP's Minnesota TCR rider along with an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made in transmission facilities that qualify for regional cost allocation under the MISO Tariff, with an offsetting credit for revenues received from other MISO utilities under the MISO Tariff for projects included in the TCR. OTP's updated Minnesota TCR rider went into effect April 1, 2012.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On February 20, 2013 the MPUC approved three of the additional projects as eligible for recovery through the TCR rider. OTP filed its annual update to the TCR rider on February 7, 2013 to include the 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 disallowed recovery of capitalized internal costs, costs in excess of CON estimates and a carrying charge in the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP will be allowed to seek recovery of these costs in a future rate case. In response to the MPUC 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. OTP filed its 2014 annual update on May 1, 2014. The MNDOC recommended approval of the 2014 update on September 24, 2014. On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015.

OTP had a regulatory asset of $3.4 million for amounts eligible for recovery through the Minnesota TCR rider that had not been billed to Minnesota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the Minnesota TCR rider of $6.3 million in 2014, $2.9 million in 2013 and $2.4 million in 2012.

Environmental Cost Recovery (ECR) Rider—In a written order issued on January 23, 2012 the MPUC granted OTP's petition for Advance Determination of Prudence (ADP) for costs associated with the design, construction and operation of the BART-compliant AQCS at Big Stone Plant attributable to serving OTP's Minnesota customers. On May 24, 2013 legislation was enacted in Minnesota which allowed OTP to file an emission-reduction rider for recovery of the revenue requirements of the AQCS. The legislation authorizes the rider to allow a current return on investment, including Construction Work in Progress (CWIP), at the level approved in OTP's most recent general rate case, unless a different return is determined by the MPUC to be in the public interest. 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 include a current return on the project's CWIP balance at the level approved in OTP's most recent general rate case. OTP filed its 2014 annual update on July 31, 2014, requesting a $4.1 million annual increase in the rider from $6.1 million to $10.2 million. The MPUC approved OTP's ECR rider annual update request on November 24, 2014, effective December 1, 2014. Because the effective date was two months behind the anticipated implementation date for the updated rate and a portion of the requested increase had been collected under the initial rate, the approved updated rate is based on a revenue requirement of $9.8 million. The rate will continue to be updated in annual filings with the MPUC until the costs are rolled into base rates at an undetermined future date.

OTP had a regulatory asset of $0.2 million for amounts eligible for recovery through the Minnesota ECR rider that had not been billed to Minnesota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the Minnesota ECR rider in 2014 of $6.9 million.

Big Stone II Project Cost Recovery—OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period which began on October 1, 2011. The amount of Big Stone II generation costs incurred by OTP that were deemed recoverable from Minnesota ratepayers as part of the rates established in that proceeding was $3.2 million. Because OTP was not allowed to earn a return on these deferred costs over the 60-month recovery period, the recoverable amount of $3.2 million was discounted to its present value of $2.8 million using OTP's incremental borrowing rate, in accordance with ASC Topic 980, Regulated Operations (ASC 980) accounting requirements. Transmission-related project costs of $3.2 million remained in CWIP as active project costs at the time of the order.

Approximately $0.4 million of the total Minnesota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP transmission line project in the first quarter of 2013. The remaining transmission costs, along with accumulated AFUDC, were transferred from CWIP to a regulatory asset account in May 2013, based on recovery granted in the April 25, 2011 order. Because OTP was not allowed to earn a return on these deferred costs over their anticipated recovery period, the recoverable amount of approximately $3.5 million was discounted to its present value using OTP's incremental borrowing rate. In May 2013, OTP recorded a charge of $0.7 million related to the discount in accordance with ASC 980 accounting requirements. In June 2014, OTP recorded an additional discount of $0.3 million to reflect changes in the end date of the anticipated recovery period from September 2020 to December 2022.

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.

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. On March 21, 2012 the NDPSC approved an update to OTP's NDRRA effective April 1, 2012. The updated NDRRA recovered $9.9 million over the period April 1, 2012 through March 31, 2013. On December 28, 2012 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2013. The update resulted in a rate reduction, so the NDPSC did not issue an order suspending the rate change. Consequently, pursuant to statute, OTP was allowed to implement updated rates effective April 1, 2013. On July 10, 2013, the NDPSC approved the updated rates implemented on April 1, 2013. The NDPSC approved OTP's most recent annual update to the NDRRA on March 12, 2014 with an effective date of April 1, 2014. The update approved on March 12, 2014 resulted in a 13.5% reduction in the NDRRA rate. On December 31, 2014 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2015.

OTP had a regulatory liability of $1.0 million as of December 31, 2014 for amounts billed to North Dakota customers that were subject to refund through the NDRRA rider. OTP recognized revenue for amounts eligible for recovery through the NDRRA rider of $7.5 million in 2014, $8.6 million in 2013 and $9.3 million in 2012.

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. On April 29, 2011 OTP filed a request for an initial North Dakota TCR rider with the NDPSC, which was approved on April 25, 2012 and effective May 1, 2012. On August 31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider. The NDPSC approved the annual update on December 12, 2012 with an effective date of January 1, 2013. On August 30, 2013 OTP filed its annual update to its North Dakota TCR rider rate, which was approved on December 30, 2013 and became effective January 1, 2014. On August 29, 2014 OTP filed its annual update to the North Dakota TCR rider rate. Within this TCR filing, as required by the order for the North Dakota Big Stone II rider, OTP included the over-collection of North Dakota Big Stone II abandoned plant costs of $0.1 million. The NDPSC approved the annual update on December 17, 2014 with an effective date of January 1, 2015.

OTP had a regulatory asset of $0.9 million for amounts eligible for recovery through the North Dakota TCR rider that had not been billed to North Dakota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the North Dakota TCR rider of $5.8 million in 2014, $3.2 million in 2013 and $1.4 million in 2012.

Environmental Cost Recovery Rider—On May 9, 2012 the NDPSC approved OTP's application for an ADP related to the Big Stone Plant AQCS. On February 8, 2013 OTP filed a request with the NDPSC 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. On December 18, 2013 the NDPSC approved OTP's North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on or after January 1, 2014. On March 31, 2014 OTP filed its 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. On July 10, 2014 the NDPSC approved OTP's 2014 ECR rider annual update request with an August 1, 2014 implementation date.

OTP had a regulatory asset of $0.7 million for amounts eligible for recovery through the North Dakota ECR rider that had not been billed to North Dakota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the North Dakota ECR rider of $5.9 million in 2014 and $2.3 million in 2013.

Big Stone II Project—In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC advocacy staff, OTP and the North Dakota Large Industrial Energy Group, Interveners. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excluded $2.6 million of project transmission-related costs) was determined to be $10.1 million, of which $4.1 million represents North Dakota's jurisdictional share.

OTP included in its total recovery amount a carrying charge of approximately $0.3 million on the North Dakota share of Big Stone II generation costs for the period from September 1, 2009 through the date the recovery of costs began based on OTP's average 2009 AFUDC rate of 7.65%. Because OTP would not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of $4.3 million was discounted to its then present value of $3.9 million using OTP's incremental borrowing rate, in accordance with ASC 980 accounting requirements. The North Dakota portion of Big Stone II generation costs was recovered over a 36-month period which began on August 1, 2010.

The North Dakota jurisdictional share of Big Stone II costs incurred by OTP related to transmission was $1.1 million. Approximately $0.3 million of the total North Dakota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP during the first quarter of 2013. On July 30, 2013 the NDPSC approved OTP's request to continue the Big Stone II cost recovery rates for an additional eight months through March 31, 2014 to recover the remaining North Dakota share of Big Stone II transmission-related costs plus accrued AFUDC totaling $1.0 million. As of April 1, 2014 North Dakota customer's bills no longer include a charge for North Dakota share of Big Stone II costs. OTP had a regulatory liability of $0.1 million as of December 31, 2014 for amounts billed to North Dakota customers that will be refunded through the North Dakota TCR rider.

South Dakota

2010 General Rate Case—On April 21, 2011, the SDPUC issued a written order approving an overall revenue increase for OTP of approximately $643,000 (2.32%) and an overall rate of return on rate base of 8.50%. Final rates were effective with bills rendered on and after June 1, 2011.

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. OTP submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. The SDPUC approved an annual update to OTP's South Dakota TCR on April 23, 2013 with an effective date of May 1, 2013. The SDPUC approved OTP's following annual update to its South Dakota TCR on February 18, 2014 with an effective date of March 1, 2014. OTP filed another annual update on October 31, 2014, which was approved by the SDPUC on February 13, 2015 with an effective date of March 1, 2015.

OTP had a regulatory liability of less than $0.1 million as of December 31, 2014 for amounts billed to South Dakota customers that were subject to refund through the South Dakota TCR rider. OTP recognized revenue for amounts eligible for recovery through the South Dakota TCR rider of $1.2 million in 2014, $0.8 million in 2013 and $0.4 million in 2012.

Environmental Cost Recovery Rider—On March 30, 2012 OTP requested approval from the SDPUC for an ECR rider to recover costs associated with the Big Stone Plant AQCS. On April 17, 2013 OTP filed a request to either suspend or withdraw this filing. The SDPUC approved withdrawing this filing on April 23, 2013. On August 29, 2014 OTP filed a new request with the SDPUC for an ECR rider to recover costs associated with new environmental measures including costs to comply with mercury and air toxics standards. On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover the costs of the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) projects, with an effective date of December 1, 2014.

OTP had a regulatory asset of less than $0.1 million for amounts eligible for recovery through the South Dakota ECR rider that had not been billed to South Dakota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the South Dakota ECR rider of $0.2 million in 2014.

Big Stone II Project—OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately $1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP is allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted. OTP transferred the South Dakota portion of the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP.

A portion of the Big Stone II transmission costs were transferred out of CWIP in February 2013 to be included within the Big Stone South - Brookings MVP. On March 28, 2013 OTP filed a petition with the SDPUC requesting deferred accounting for the remaining unrecovered Big Stone II transmission costs until OTP's next South Dakota general rate case. The petition was approved by the SDPUC on April 23, 2013 and in May 2013 OTP transferred the remaining South Dakota jurisdictional portion of unrecovered Big Stone II transmission costs plus accumulated AFUDC totaling $0.2 million from CWIP to the Big Stone II Unrecovered Project Costs – South Dakota regulatory asset accounts.

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.

Effective January 1, 2010 the FERC authorized OTP's implementation of a forward looking formula transmission rate under the MISO Tariff. OTP was also authorized by the FERC to recover in its formula rate (1) 100% of prudently incurred CWIP in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects in which OTP is a joint owner: the Fargo Project, the Bemidji Project and the Brookings Project.

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.

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. On June 7, 2013, in response to a challenge to the MVP cost allocation heard before the United States Court of Appeals, Seventh Circuit, the Court ruled in favor of MISO and MISO transmission owners, issuing an order affirming the FERC's approval of the MVP cost allocation. On February 24, 2014 the U.S. Supreme Court denied petitions for a writ of certiorari of the Seventh Circuit's decision upholding the FERC's MVP orders. The petitioners did not seek rehearing.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including

OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the current 12.38% return on equity used in MISO's transmission rates to a proposed 9.15%. A group of MISO transmission owners have filed responses to the complaint, defending the current return on equity and seeking dismissal of the complaint. On October 16, 2014 the FERC issued an order finding that the current MISO return on equity may be unjust and unreasonable and setting the issue for hearing, subject to the outcome of settlement discussion. Settlement discussions did not resolve the dispute and the FERC set the proceeding to a Track II Hearing for complex cases that can take several months to decide, with a FERC decision anticipated in fall 2016 at the earliest. 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 (RTO) participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the resolution of the return on equity complaint proceeding.

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, 2014			Remaining Recovery/ Refund
(in thousands)	Current	Long-Term	Total	Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$7,464	$ 101,526	$108,990	see note
Deferred Marked-to-Market Losses[1]	4,492	9,396	13,888	72 months
Conservation Improvement Program Costs and Incentives[2]	5,843	2,500	8,343	18 months
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	5,190	5,190	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	592	3,207	3,799	96 months
Minnesota Transmission Rider Accrued Revenues[2]	943	2,455	3,398	24 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	2,585	807	3,392	24 months
Debt Reacquisition Premiums[1]	351	1,890	2,241	213 months
Deferred Income Taxes[1]	--	2,086	2,086	asset lives
Recoverable Fuel and Purchased Power Costs[1]	1,114	--	1,114	12 months
North Dakota Transmission Rider Accrued Revenues[2]	859	--	859	12 months
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	743	843	101 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	706	--	706	12 months
Minnesota Environmental Cost Recovery Rider Accrued Revenues[2]	186	--	186	12 months
Minnesota Renewable Resource Rider Accrued Revenues[2]	--	68	68	see note
South Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	38	--	38	12 months
Total Regulatory Assets	$25,273	$ 129,868	$155,141	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$ 74,237	$74,237	asset lives
Deferred Income Taxes	--	1,550	1,550	asset lives
North Dakota Renewable Resource Rider Accrued Refund	933	85	1,018	15 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	784	784	see note
Deferred Marked-to-Market Gains	--	257	257	67 months
Big Stone II Over Recovered Project Costs – North Dakota	147	--	147	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	100	106	228 months
South Dakota Transmission Rider Accrued Refund	48	--	48	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	24	--	24	12 months
Total Regulatory Liabilities	$1,158	$ 77,013	$78,171	
Net Regulatory Asset Position	$24,115	$ 52,855	$76,970	

[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.

(in thousands)	December 31, 2013 Current	Long-Term	Total	Remaining Recovery/ Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$4,095	$ 55,012	$59,107	see note
Deferred Marked-to-Market Losses[1]	3,008	8,674	11,682	60 months
Conservation Improvement Program Costs and Incentives[2]	4,945	3,959	8,904	18 months
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	4,646	4,646	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	558	3,967	4,525	81 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	1,351	1,753	3,104	24 months
Debt Reacquisition Premiums[1]	351	2,241	2,592	225 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	2,331	--	2,331	12 months
Deferred Income Taxes[1]	--	1,805	1,805	asset lives
Big Stone II Unrecovered Project Costs – South Dakota[2]	101	843	944	113 months
North Dakota Renewable Resource Rider Accrued Revenues[2]	--	762	762	15 months
Recoverable Fuel and Purchased Power Costs[1]	760	--	760	12 months
Big Stone II Unrecovered Project Costs – North Dakota[1]	375	--	375	3 months
Minnesota Renewable Resource Rider Accrued Revenues[2]	--	68	68	see note
South Dakota Transmission Rider Accrued Revenues[2]	32	--	32	12 months
Deferred Holding Company Formation Costs[1]	27	--	27	6 months
General Rate Case Recoverable Expenses – South Dakota[1]	6	--	6	1 month
Total Regulatory Assets	$17,940	$ 83,730	$101,670	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$ 71,454	$71,454	asset lives
Deferred Income Taxes	--	1,960	1,960	asset lives
Minnesota Transmission Rider Accrued Refund	670	--	670	12 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	289	289	see note
North Dakota Renewable Resource Rider Accrued Refund	261	--	261	12 months
North Dakota Transmission Rider Accrued Refund	215	--	215	12 months
Deferred Marked-to-Market Gains	6	117	123	56 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	5	106	111	240 months
South Dakota – Nonasset-Based Margin Sharing Excess	38	--	38	12 months
Total Regulatory Liabilities	$1,195	$ 73,926	$75,121	
Net Regulatory Asset Position	$16,745	$ 9,804	$26,549	

[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 Gains and Losses recorded as of December 31, 2014 are related 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 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 generation project.

Minnesota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to Minnesota customers as of December 31, 2014.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up relates to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-up also includes 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.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 213 months.

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.

North Dakota Transmission 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, 2014.

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 generation project.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the North Dakota share of amounts invested in the construction of the Big Stone Plant AQCS project, net of amounts billed under the rider.

Minnesota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the Minnesota share of amounts invested in the construction of the Big Stone Plant AQCS project, net of amounts billed under the rider.

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 MNRRA rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case.

South Dakota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the South Dakota share of amounts invested in the construction of the Big Stone Plant AQCS project and Hoot Lake Plant MATS project, net of amounts billed under the rider.

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 Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2014.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relate 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.

Big Stone II Over Recovered Project Costs – North Dakota represent amounts collected from North Dakota customers in excess of the North Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II generation project. The December 31, 2014 liability will be refunded to North Dakota customers through an adjustment to revenue requirements under the North Dakota TCR rider.

South Dakota Transmission Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that are refundable to South Dakota customers as of December 31, 2014.

South Dakota – Nonasset-Based Margin Sharing Excess represents 25% of OTP's South Dakota share of actual profit margins on nonasset-based wholesale sales of electricity. The excess margins accumulated annually will be subject to refund through future retail rate adjustments in South Dakota in the following year.

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 extraordinary expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Forward Contracts Classified as Derivatives

Electricity Contracts

All of OTP's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. OTP's objective in entering into forward contracts for the purchase and sale of energy is to meet the energy requirements of its retail customers and to optimize the use of its generating and transmission facilities. OTP's intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. Prior to December 2014, OTP also entered into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales. Effective December 31, 2014 OTP discontinued its trading activities not directly associated with serving retail customers.

Market prices used to value OTP's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into Level 3 of the fair value hierarchy set forth in ASC 820.

Electric operating revenues include wholesale electric sales and net unrealized derivative gains on forward energy contracts, the acquisition and settlement of financial transmission rights and congestion revenue rights options in the MISO and Electric Reliability Council of Texas (ERCOT) markets and daily settlements of virtual transactions in the MISO, ERCOT and California Independent Transmission System Operator markets, broken down as follows for the years ended December 31:

(in thousands)	2014	2013	2012
Wholesale Sales - Company-Owned Generation	$11,160	$14,846	$12,951
Revenue from Settled Contracts at Market Prices	131,952	133,238	160,987
Market Cost of Settled Contracts	(130,908)	(132,055)	(159,500)
Net Margins on Settled Contracts at Market	1,044	1,183	1,487
Marked-to-Market Gains on Settled Contracts	263	3,039	7,864
Marked-to-Market Losses on Settled Contracts	(276)	(2,722)	(7,974)
Net Marked-to-Market (Losses) Gains on Settled Contracts	(13)	317	(110)
Unrealized Marked-to-Market Gains on Open Contracts	--	215	284
Unrealized Marked-to-Market Losses on Open Contracts	(--)	(100)	(235)
Net Unrealized Marked-to-Market Gains on Open Contracts	--	115	49
Wholesale Electric Revenue	$12,191	$16,461	$14,377

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of December 31, 2014 and December 31, 2013, and the change in the Company's consolidated balance sheet position from December 31, 2013 to December 31, 2014 and December 31, 2012 to December 31, 2013:

(in thousands)	December 31, 2014	December 31, 2013
Other Current Asset – Marked-to-Market Gain	$ 257	$ 338
Regulatory Asset – Current Deferred Marked-to-Market Loss	4,492	3,008

Regulatory Asset – Long-Term Deferred Marked-to-Market Loss		9,396			8,674	
Total Assets		14,145			12,020	
Current Liability – Marked-to-Market Loss		(13,888	)		(11,782	)
Regulatory Liability – Current Deferred Marked-to-Market Gain		--			(6	)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain		(257	)		(117	)
Total Liabilities		(14,145	)		(11,905	)
Net Fair Value of Marked-to-Market Energy Contracts	$	--		$	115	

(in thousands)	Year ended December 31, 2014	Year ended December 31, 2013
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	$ 115	$ 49
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(72)	(49)
Changes in Fair Value of Contracts Entered into in Prior Periods	(43)	--
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	--
Changes in Fair Value of Contracts Entered into in Current Period	--	115
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ --	$ 115

OTP has established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). OTP had no exposure at December 31, 2014 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

Individual counterparty exposures for certain contracts can be offset according to legally enforceable netting arrangements. However, the Company does not net offsetting payables and receivables or derivative assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet. The amounts of derivative asset and derivative liability balances that were subject to legally enforceable netting arrangements as of December 31, 2014 and December 31, 2013 are indicated in the following table:

(in thousands)	December 31, 2014	December 31, 2013
Derivative Assets Subject to Legally Enforceable Netting Arrangements	$ 257	$ 400
Derivative Liabilities Subject to Legally Enforceable Netting Arrangements	(14,230)	(11,782)
Net Balance Subject to Legally Enforceable Netting Arrangements	$ (13,973)	$ (11,382)

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, 2014 and December 31, 2013:

Current Liability – Marked-to-Market Loss (in thousands)	December 31, 2014	December 31, 2013
Loss Contracts Covered by Deposited Funds or Letters of Credit	$ 45	$ --
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade[1]	13,888	11,679
Loss Contracts with No Ratings Triggers or Deposit Requirements	297	103
Total Current Liability – Marked-to-Market Loss	$ 14,230	$ 11,782
[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	$ 13,888	$ 11,679
Offsetting Gains with Counterparties under Master Netting Agreements	(257)	(117)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$ 13,631	$ 11,562

6. Common Shares and Earnings Per Share

Shelf Registration

On May 11, 2012 the Company filed a shelf registration statement with the U.S. Securities and Exchange Commission (SEC) under which it 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.

Common Share Distribution Agreement

On May 14, 2012 the Company entered into a Distribution Agreement (the Agreement) with J.P. Morgan Securities (JPMS) under which the Company may offer and sell its common shares from time to time through JPMS, as the Company's distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75 million.

Under the 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. JPMS will receive from the Company a commission of 2% of the gross sales price per share for any shares sold through it as the Company's distribution agent under the Agreement.

The Company is not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to the Company's existing shelf registration statement, as amended. In 2014, the Company began selling common shares using its At-the-Market offering program under the Agreement.

2014 Common Stock Activity

In 2014, in addition to selling common shares under the At-the-Market offering program, the Company also began issuing shares to meet the requirements of its Automatic Dividend Reinvestment and Share Purchase Plan, Employee Stock Purchase Plan and Employee Stock Ownership Plan, rather than purchasing shares in the open market. Following is a reconciliation of the Company's common shares outstanding from December 31, 2013 through December 31, 2014:

Common Shares Outstanding, December 31, 2013	36,271,696
Issuances:	
At-the-Market Offering	519,636
Automatic Dividend Reinvestment and Share Purchase Plan:	
Dividends Reinvested	180,818
Cash Invested	81,533
Employee Stock Purchase Plan:	
Cash Invested	39,222
Dividends Reinvested	25,694
Restricted Stock Issued to Employees	26,700
Employee Stock Ownership Plan	22,650
Executive Stock Performance Awards (2011-2013 shares earned)	22,630
Stock Options Exercised	20,800
Restricted Stock Issued to Directors	16,800
Vesting of Restricted Stock Units	14,305
Directors Deferred Compensation	498
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(20,554)
Forfeiture of Unvested Restricted Stock	(4,375)
Common Shares Outstanding, December 31, 2014	37,218,053

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 1,685,653 were available for issuance as of December 31, 2014. 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. 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, 460,264 were available for purchase as of December 31, 2014. 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, 39,222 common shares were issued in 2014, 43,837 common shares were purchased in the open market in 2013 and 60,439 common shares were purchased in the open market in 2012. 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
On May 11, 2012 the Company filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders, customers or residents of certain states who participate in the Plan to be either new issue common shares or common shares purchased in the open market. In 2014, 288,045 new common shares were issued and 7,480 common shares were purchased in the open market to provide shares for the plan. Common shares purchased in the open market to provide shares for the Plan totaled 284,632 in 2013 and 258,092 in 2012, leaving 661,751 common shares available for issuance under the Plan as of December 31, 2014.

Earnings Per Share
The numerator used in the calculation of both basic and diluted earnings per common share is earnings available for common shares with no adjustments in 2014, 2013 or 2012. 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 outstanding shares for the following: (1) all potentially dilutive stock options, (2) underlying shares related to nonvested restricted stock units granted to employees, (3) nonvested restricted shares, (4) shares expected to be awarded for stock performance awards granted to executive officers, and (5) shares expected to be issued under the deferred compensation program for directors. Adjustments to the denominator used to calculate diluted earnings per share of 238,162 shares, 203,583 shares and 194,240 shares in 2014, 2013 and 2012, respectively, resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in each of the years ended December 31, 2014, 2013 and 2012.

The following outstanding stock options with exercise prices greater than the average market price of the underlying shares were excluded from the calculation of diluted earnings per share for the years ended December 31, 2014, 2013 and 2012:

Year	Options Outstanding	Range of Exercise Prices
2014	--	--
2013	--	--
2012	92,497	$24.93 – $27.245

7. Share-Based Payments

Purchase Plan
The Purchase Plan allows 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 $175,000 in 2014, $143,000 in 2013 and $179,000 in 2012. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

Stock Options Granted Under the 1999 Incentive Plan
The Company has granted 2,041,500 options for the purchase of the Company's common stock under the 1999 Stock Incentive Plan (1999 Incentive Plan). All of the options granted had vested or were forfeited as of December 31, 2007. 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.

The following table provides information about options outstanding as of December 31, 2014:

Exercise Price	Outstanding and Exercisable as of 12/31/14	Remaining Contractual Life
$24.93	12,750	Expire on April 10, 2015

Presented below is a summary of the stock options activity:

Stock Option Activity	2014		2013		2012	
	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	34,700	$25.69	92,497	$26.59	156,397	$28.53
Granted	--	--	--	--	--	--
Exercised	20,800	26.11	56,109	27.12	--	--
Forfeited or Expired	1,150	26.495	1,688	27.245	63,900	31.34
Outstanding, End of Year	12,750	24.93	34,700	25.69	92,497	26.59
Exercisable, End of Year	12,750	24.93	34,700	25.69	92,497	26.59
Cash Received for Options Exercised		$543,000		$1,522,000		--
Intrinsic Value of Options Exercised		89,000		152,000		--
Fair Value of Options Granted During Year		none granted		none granted		none granted

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 14, 2014 the Company's board of directors granted 16,800 shares of restricted stock to the Company's nonemployee directors. The grant-date fair value of each share of restricted stock granted on April 14, 2014 was $29.41 per share, the average of the high and low market price on the date of grant. The restricted shares granted in 2014 vest 25% per year on April 8 of each year in the period 2015 through 2018 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	2014		2013		2012	
	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	42,483	$25.03	56,900	$21.84	54,250	$23.26
Granted	16,800	29.41	17,333	30.77	24,000	21.32
Vested	21,233	24.11	29,750	21.87	21,350	24.86
Forfeited	--		2,000	31.03	--	
Nonvested, End of Year	38,050	27.47	42,483	25.03	56,900	21.84
Compensation Expense Recognized		$ 416,000		$ 611,000		$ 552,000
Fair Value of Shares Vested in Year		512,000		651,000		531,000

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. On April 14, 2014 the

Company's board of directors granted 26,700 shares of restricted stock to the Company's executive officers under the 2014 Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2015 through 2018 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. The grant-date fair value of each share of restricted stock granted in 2014 was $29.41 per share, the average of the high and low market price on the date of grant.

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

Employees’ Restricted Stock Awards	2014		2013		2012	
	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	48,315	$25.04	47,645	$21.82	34,868	$22.86
Granted	26,700	29.41	17,000	31.03	26,120	21.48
Awards Vested	25,360	24.80	16,330	21.89	11,518	24.14
Forfeited	4,375	28.03	--		1,825	22.20
Nonvested, End of Year	45,280	27.46	48,315	25.04	47,645	21.82
Compensation Expense Recognized		$ 998,000		$ 427,000		$ 325,000
Fair Value of Awards Vested		629,000		358,000		278,000

Stock-based compensation expense recognized in 2014 for the Company’s restricted stock awards reflects the accelerated recognition of expense for outstanding and unvested restricted stock awards of executives who are, or will be, eligible for retirement, as defined in the restricted stock award agreements, prior to the vesting dates of the awards.

Restricted Stock Units Granted to Employees

On April 14, 2014 the Company’s board of directors granted 11,800 restricted stock units to key employees under the 2014 Incentive Plan payable in common shares on April 8, 2018, the date the units vest. The grant-date fair value of each restricted stock unit was $24.95 per share based on the average of the high and low market price of the Company’s common stock on April 14, 2014, discounted for the value of the dividend exclusion over the four-year vesting period.

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	2014		2013		2012	
	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	56,180	$19.79	60,665	$18.11	73,815	$20.95
Granted	11,800	24.95	15,150	25.30	15,800	17.66
Reinstated	75	30.81	--		--	
Vested	14,305	18.05	17,535	18.73	20,750	27.13
Forfeited	7,850	18.90	2,100	19.88	8,200	19.97
Nonvested, End of Year	45,900	21.82	56,180	19.79	60,665	18.11
Compensation Expense Recognized		$ 194,000		$ 275,000		$ 256,000
Fair Value of Units Converted in Year		258,000		328,000		563,000

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company’s board of directors has approved stock performance award agreements 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. 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. The terms of the outstanding awards dictate that these 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.

On April 14, 2014 the Company’s board of directors granted performance share awards to the Company’s executive officers under the 2014 Incentive Plan for the 2014-2016 performance measurement period.

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	Shares Used To Estimate Expense	Average Grant-Date Fair Value	Expense Recognized in the Year Ended December 31, 2014	2013	2012	Shares Awarded
2014-2016	159,450	106,300	$ 22.94	$1,422,000	$--	$--	--
2013-2015	90,600	45,300	$ 37.51	458,000	580,000	--	--
2012-2014	148,400	74,200	$ 21.75	142,000	1,686,000	1,001,000	89,991
2011-2013	90,600	45,300	$ 23.61	--	412,000	254,000	48,730
2010-2012	138,800	69,400	$ 20.97	--	--	--	49,500
Total				$2,022,000	$2,678,000	$1,255,000	188,221

Stock-based payment expense recognized in 2014 reflects the accelerated recognition of expense for outstanding and unvested awards of executives who are, or will be, eligible for retirement, as defined in the performance award agreements, prior to the vesting dates of the awards.

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, 6,600 granted in 2012, 3,300 granted in 2011 and 4,000 granted in 2010.

The shares awarded 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 ranking of 21 out of 48 companies in its EEI peer group and a resulting payout at 121.28% of target.

The shares awarded shown in the table above for the 2011-2013 performance period include shares received in 2014 by active participants in the plan on December 31, 2013, based on the Company achieving a ranking of 22 out of 49 companies in its EEI peer group and a resulting payout at 117.86% of target. The shares awarded shown in the table above for the 2011-2013 performance period also include 26,100 shares received by a participant under an executive employment agreement on resignation in 2011.

The Company’s 2010-2012 total shareholder return ranking resulted in no incentive share awards for the Company’s active plan participants for the 2010-2012 performance measurement period. The shares awarded shown in the table above for the 2010-2012 performance periods reflect only shares received under executive employment agreements.

As of December 31, 2014 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 $3.0 million (before income taxes), which will be amortized over a weighted average period of 1.9 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, 2014 the Company was in compliance with the debt 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, 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 45.0% and 55.0%. OTP's equity to total capitalization ratio including short-term debt was 49.8% as of December 31, 2014. Total capitalization for OTP cannot currently exceed $987 million.

9. Commitments and Contingencies of Continuing Operations

Construction and Other Purchase Commitments

At December 31, 2014 OTP had commitments under contracts in connection with construction programs extending into 2018 of approximately $106.6 million.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2039. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2015, 2016, 2017 and 2040. 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 $10,165,000, $8,560,000 and $7,951,000 for 2014, 2013 and 2012, respectively.

The amounts of the Company's construction program commitments and commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases for continuing operations as of December 31, 2014, are as follows:

				Operating Leases		
(in thousands)	Construction Program Commitments	Capacity and Energy Requirements	Coal and Freight Purchase Commitments	OTP	Nonelectric	Total
2015	$ 48,708	$ 34,383	$ 49,739	$1,958	$ 5,114	$7,072
2016	40,653	22,812	22,943	1,371	4,056	5,427
2017	17,163	22,123	28,146	978	3,333	4,311
2018	100	22,729	23,135	990	2,744	3,734
2019	--	24,532	23,072	1,002	1,223	2,225
Beyond 2019	--	217,359	598,742	10,824	3,766	14,590
Total	$ 106,624	$ 343,938	$ 745,777	$17,123	$ 20,236	$37,359

Contingencies

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 and litigation matters. Should all of these known items result in liabilities being incurred, the loss could be as high as $2.0 million.

On June 21, 2010 the EPA published a proposed rule that outlines two possible options to regulate disposal of coal ash generated from the combustion of coal by electric utilities under the Resource Conservation and Recovery Act (RCRA). In one option, the EPA would propose to list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth the

EPA's hazardous waste regulatory program, which regulates the generation, handling, transport and disposal of wastes. Under the other proposed regulatory option, the EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for nonhazardous solid wastes. On December 19, 2014 the EPA announced a final rule following the Subtitle D nonhazardous provisions. 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. 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. The EPA is also considering future regulation of coal ash under Subtitle C. Publication of the final rule will open a 90-day window within which petitions for judicial review may be filed in the D.C. Circuit. Challenges by environmental groups are possible and the outcome of such challenges cannot be predicted. Thus, uncertainty regarding the status of this rule is likely to continue for some time.

<u>Other</u>

The Company is a party to litigation 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, 2014 will not be material.

10. Short-Term and Long-Term Borrowings and Preferred Stock Redemption

Short-Term Debt

The following table presents the status of the Company's lines of credit as of December 31, 2014 and December 31, 2013:

(in thousands)	Line Limit	In Use on December 31, 2014	Restricted due to Outstanding Letters of Credit	Available on December 31, 2014	Available on December 31, 2013
Otter Tail Corporation Credit Agreement	$150,000	$ 10,854	$ 274	$138,872	$149,341
OTP Credit Agreement	170,000	--	560	169,440	116,975
Total	$320,000	$ 10,854	$ 834	$308,312	$266,316

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2014 was $41,348,000 on October 16, 2014 and the average daily balance of debt outstanding during 2014 was $17,868,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2014 was 1.9% compared with 1.9% in 2013. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2014 was $97,000,000 on February 13, 2014 and the average daily balance of debt outstanding during 2014 was $12,815,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2014 was 1.4% compared with 1.4% in 2013. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2014 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 $150 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 November 3, 2014 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2018 to October 29, 2019. 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 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 November 3, 2014 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2018 to October 29, 2019. 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 Retirements, Preferred Stock Redemption and Debt Issuances

Debt Retirements and Preferred Stock Redemption

On March 1, 2013 OTP entered into a Credit Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan) providing for a $40.9 million unsecured term loan (the Term Loan) to OTP originally due on June 1, 2014, which was fully drawn on March 1, 2013. The Loan Agreement was amended on October 29, 2013 to extend the due date on the Term Loan to January 15, 2015. Borrowings under the Loan Agreement bore interest at LIBOR plus 0.875%. On March 1, 2013 OTP utilized approximately $25.1 million of Term Loan proceeds to fund the redemption price for all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on that date, in each case for which OTP paid debt service. All such bonds had been called for redemption in full on March 1, 2013. Also on March 1, 2013, OTP utilized approximately $15.7 million of Term Loan proceeds to satisfy an intercompany note to the Company that had a balance and interest rate designed to equate to the balances and dividend rates of the Company’s cumulative preferred shares. Those cumulative preferred shares were redeemed on March 1, 2013 for $15.7 million, including $0.2 million in call premiums charged to equity and included with preferred dividends paid and as part of the Company’s preferred dividend requirement for the year ended December 31, 2013. On February 27, 2014 OTP used a portion of the proceeds from the issuance of notes under the 2013 Note Purchase Agreement (as defined below) to retire early the Term Loan.

On November 6 and 25, 2013 the Company purchased, in two separate transactions, $12,933,000 and $34,737,000, respectively, of its outstanding 9.000% notes due 2016 (the 2016 Notes), originally issued in the aggregate principal amount of $100 million. The purchased 2016 Notes (the Purchased 2016 Notes) were subsequently retired and are no longer outstanding. The remaining $52,300,000 principal amount of 2016 Notes outstanding, unless redeemed early or otherwise repaid, will mature and become due and payable on December 15, 2016. The price paid for the Purchased 2016 Notes was $59,404,000, which includes the principal amount of the Purchased 2016 Notes, plus accrued interest of $1,845,000 through the respective purchase dates and a negotiated premium of $9,889,000 (which is less than the premium the Company would have been required to pay to redeem them under the terms of the 2016 Notes). The Company used cash on hand to fund the purchase of the Purchased 2016 Notes. The amount of the debt retired as a result of these transactions is approximately equivalent to the remaining amount of debt that was associated with the operating companies the Company divested over the last two years. On repayment, $363,000 in unamortized debt expense related to the 2016 Notes was immediately recognized as expense along with the $9,889,000 negotiated premium which, in total, reduced diluted earnings per share by $0.17 in 2013.

On July 13, 2012 the Company prepaid in full its outstanding $50 million, 8.89% Senior Unsecured Note due November 30, 2017 (the Cascade Note) issued pursuant to the Note Purchase Agreement dated as of February 23, 2007, as amended, between the Company and Cascade Investment, L.L.C. (Cascade). Immediately before the prepayment, the Cascade Note bore interest at 8.89% annually. The price paid by the Company to prepay the Cascade Note was $63,031,000, which included the principal amount of the Cascade Note plus accrued interest of $531,000 and a negotiated prepayment premium of $12,500,000. The Company used funds available under the Otter Tail Corporation Credit Agreement for the prepayment. This early retirement reflects the Company’s desire to lower its long-term debt outstanding given its recent divestitures. On repayment, $606,000 in unamortized debt expense related to this note was immediately recognized as expense along with the $12,500,000 negotiated prepayment premium which, in total, reduced diluted earnings per share by $0.22 in 2012.

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 the Term Loan as discussed above 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, 2012 the Company filed a shelf registration statement with the SEC under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement, which expires on May 10, 2015.

The aggregate amounts of maturities on bonds outstanding and other long term obligations at December 31, 2014 for each of the next five years are:

(in thousands)	2015	2016	2017	2018	2019
Aggregate Amounts of Debt Maturities	$201	$52,544	$33,228	$187	$172

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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, 2014 and December 31, 2013:

December 31, 2014 (in thousands)	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$--	$ 10,854	$ 10,854
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	--	256	256
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	--	1,105	1,105
Total	$445,000	$ 53,691	$ 498,691
Less: Current Maturities	--	201	201
Unamortized Debt Discount	--	1	1
Total Long-Term Debt	$445,000	$ 53,489	$ 498,489
Total Short-Term and Long-Term Debt (with current maturities)	$445,000	$ 64,544	$ 509,544

December 31, 2013 (in thousands)	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$51,195	$ --	$ 51,195
Long-Term Debt:			
Unsecured Term Loan - LIBOR plus 0.875%, due January 15, 2015	$40,900		$ 40,900
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 6.47%, Series D, due August 20, 2037	50,000		50,000
North Dakota Development Note, 3.95%, due April 1, 2018	--	325	325
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	--	1,223	1,223
Total	$335,900	$ 53,878	$ 389,778
Less: Current Maturities	--	188	188
Unamortized Debt Discount	--	1	1
Total Long-Term Debt	$335,900	$ 53,689	$ 389,589
Total Short-Term and Long-Term Debt (with current maturities)	$387,095	$ 53,877	$ 440,972

Financial Covenants

The Company and OTP were in compliance with the financial covenants in their debt agreements as of December 31, 2014.

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 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 Otter Tail Corporation Credit Agreement.

Under the OTP Credit Agreement and the Loan Agreement (when in effect), 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.

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, 2014, the Company adopted updated and modified mortality tables and an updated and modified mortality improvement scale that reflect longer life expectancies for plan participants. The adoption of the updated and modified mortality tables and mortality improvement scale in 2014 increased 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 2005. Although the adoption of the updated and modified tables and improvement scale will have the effect of increasing 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 January 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.

Components of net periodic pension benefit cost:

(in thousands)	2014	2013	2012
Service Cost–Benefit Earned During the Period	$4,666	$5,594	$5,084
Interest Cost on Projected Benefit Obligation	13,111	12,123	12,465
Expected Return on Assets	(16,743)	(14,521)	(14,430)
Amortization of Prior Service Cost:			
From Regulatory Asset	257	333	398
From Other Comprehensive Income[1]	7	9	11
Amortization of Net Actuarial Loss:			

From Regulatory Asset	3,400	6,600	4,910
From Other Comprehensive Income[1]	83	176	131
Net Periodic Pension Cost	$4,781	$10,314	$8,569

[1]Corporate cost included in Other Nonelectric Expenses.

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

	2014	2013	2012
Discount Rate	5.30%	4.50%	5.15%
Long-Term Rate of Return on Plan Assets	7.75%	7.75%	8.00%
Rate of Increase in Future Compensation Level	3.13%	3.13%	3.38%

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

(in thousands)	2014	2013
Regulatory Assets:		
Unrecognized Prior Service Cost	$518	$776
Unrecognized Actuarial Loss	97,722	56,051
Total Regulatory Assets	$98,240	$56,827
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	$21	$28
Unrecognized Actuarial Loss	899	448
Total Accumulated Other Comprehensive Loss	$920	$476
Noncurrent Liability	$67,061	$40,422

Funded status as of December 31:

(in thousands)	2014	2013
Accumulated Benefit Obligation	$(273,903)	$(224,365)
Projected Benefit Obligation	$(311,650)	$(254,039)
Fair Value of Plan Assets	244,589	213,617
Funded Status	$(67,061)	$(40,422)

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, 2014:

(in thousands)	2014	2013
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$213,617	$191,018
Actual Return on Plan Assets	21,874	23,044
Discretionary Company Contributions	20,000	10,000
Benefit Payments	(10,902)	(10,445)
Fair Value of Plan Assets at December 31	$244,589	$213,617
Estimated Asset Return	9.6 %	11.8 %
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$254,039	$275,634
Service Cost	4,666	5,594
Interest Cost	13,111	12,123
Benefit Payments	(10,902)	(10,445)
Actuarial Loss (Gain)	50,736	(28,867)
Projected Benefit Obligation at December 31	$311,650	$254,039

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

	2014	2013
Discount Rate	4.35%	5.30%
Rate of Increase in Future Compensation Level	3.13%	3.13%

The assumed rate of return on pension fund assets used for the determination of 2015 net periodic pension cost is 7.75%. 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:	2014	2013
Net Periodic Pension Cost	January 1, 2014	January 1, 2013
End of Year Benefit Obligations	January 1, 2014 projected to December 31, 2014	January 1, 2013 projected to December 31, 2013
Market Value of Assets	December 31, 2014	December 31, 2013

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 2015 are:

(in thousands)	2015
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$189
Amortization of Unrecognized Actuarial Loss	6,529
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Loss	161
Total Estimated Amortization	$6,884

Cash flows—The Company had no minimum funding requirement as of December 31, 2014, but made a discretionary plan contribution of $10,000,000 in January 2015.

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

(in thousands)	2015	2016	2017	2018	2019	Years 2020-2024
	$11,858	$12,462	$13,116	$13,941	$14,665	$ 85,322

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:
- o The safeguards and diversity that a prudent investor would adhere to must be present in the investment program.
- o 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:

	Permitted Range			
	< 100%	100%	105%	>=110%
Asset Class / PBO Funded Status	PBO	PBO	PBO	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, 2014 and 2013, by asset category are as follows:

Asset Allocation	2014	2013
Large Capitalization Equity Securities	21.0 %	21.0 %
International Equity Securities	18.9 %	21.7 %
Small and Mid-Capitalization Equity Securities	7.9 %	8.5 %
SEI Dynamic Asset Allocation Fund	5.5 %	5.2 %
Equity Securities	53.3 %	56.4 %
Fixed-Income Securities and Cash	42.7 %	39.3 %
Other - SEI Special Situation Collective Investment Trust	4.0 %	4.3 %
	100.0%	100.0%

<u>Fair Value Measurements of Pension Fund Assets</u>

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 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.

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 table presents, for each of these hierarchy levels, the Company's pension fund assets measured at fair value as of December 31, 2014 and 2013:

2014 (in thousands)	Level 1	Level 2	Level 3
Large Capitalization Equity Securities Mutual Fund	$51,404		
International Equity Securities Mutual Funds	46,287		
Small and Mid-Capitalization Equity Securities Mutual Fund	19,189		
SEI Dynamic Asset Allocation Mutual Fund	13,543		
Fixed Income Securities Mutual Funds	104,360		
Cash Management – Money Market Fund	5		
SEI Special Situation Collective Investment Trust Fund		$9,801	
Total Assets	$234,788	$9,801	$ --

2013 (in thousands)	Level 1	Level 2	Level 3
Large Capitalization Equity Securities Mutual Fund	$44,882		
International Equity Securities Mutual Funds	46,412		
Small and Mid-Capitalization Equity Securities Mutual Fund	18,151		
SEI Dynamic Asset Allocation Mutual Fund	11,159		
Fixed Income Securities Mutual Funds	83,843		
Cash Management – Money Market Fund	--		
SEI Special Situation Collective Investment Trust Fund		$9,170	
Total Assets	$204,447	$9,170	$--

The investments held by the SEI Special Situation Collective Investment Trust on December 31, 2014 and 2013 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 net asset value 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.

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.

Components of net periodic pension benefit cost:

(in thousands)	2014	2013	2012
Service Cost–Benefit Earned During the Period	$51	$51	$45
Interest Cost on Projected Benefit Obligation	1,520	1,408	1,479
Amortization of Prior Service Cost:			
From Regulatory Asset	22	22	22
From Other Comprehensive Income[1]	51	51	51
Amortization of Net Actuarial Loss:			

From Regulatory Asset	142	208	175
From Other Comprehensive Income[2]	46	313	152
Net Periodic Pension Cost	$1,832	$2,053	$1,924
[1]Amortization of Prior Service Costs from Other Comprehensive Income Charged to:			
Electric Operation and Maintenance Expenses	$20	$20	$20
Other Nonelectric Expenses	31	31	31
[2]Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:			
Electric Operation and Maintenance Expenses	$132	$193	$162
Other Nonelectric Expenses	(86)	120	(10)

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

	2014	2013	2012
Discount Rate	5.30%	4.50%	5.15%
Rate of Increase in Future Compensation Level	3.18%	3.19%	4.59%

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

(in thousands)	2014	2013
Regulatory Assets:		
Unrecognized Prior Service Cost	$91	$113
Unrecognized Actuarial Loss	3,238	1,971
Total Regulatory Assets	$3,329	$2,084
Projected Benefit Obligation Liability – Net Amount Recognized	$(35,650)	$(29,321)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	$210	$261
Unrecognized Actuarial Loss	6,881	2,465
Total Accumulated Other Comprehensive Loss	$7,091	$2,726

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, 2014 and a statement of the funded status as of December 31 of both years:

(in thousands)	2014	2013
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Employer Contributions	1,113	1,137
Benefit Payments	(1,113)	(1,137)
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$29,321	$31,925
Service Cost	51	51
Interest Cost	1,520	1,408
Benefit Payments	(1,113)	(1,137)
Plan Amendments	--	--
Actuarial Loss (Gain)	5,871	(2,926)
Projected Benefit Obligation at December 31	$35,650	$29,321
Reconciliation of Funded Status:		
Funded Status at December 31	$(35,650)	$(29,321)
Unrecognized Net Actuarial Loss	10,119	4,436
Unrecognized Prior Service Cost	301	374
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(25,230)	$(24,511)

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

2014	2013

Discount Rate	4.35%	5.30%
Rate of Increase in Future Compensation Level	3.15%	3.18%

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 2015 are:

(in thousands)	2015
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$16
Amortization of Unrecognized Actuarial Loss	334
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	38
Amortization of Unrecognized Actuarial Loss	602
Total Estimated Amortization	$990

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:

						Years
(in thousands)	2015	2016	2017	2018	2019	2020-2024
	$1,178	$1,399	$1,376	$1,423	$1,516	$ 10,904

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. On adoption of Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, in January 1993, the Company elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years. The transition obligation was fully recognized by December 31, 2012. There are no plan assets.

Components of net periodic postretirement benefit cost:

(in thousands)	2014	2013	2012
Service Cost–Benefit Earned During the Period	$1,055	$1,421	$1,544
Interest Cost on Projected Benefit Obligation	2,200	2,050	2,574
Amortization of Transition Obligation			
From Regulatory Asset	--	--	729
From Other Comprehensive Income[1]	--	--	19
Amortization of Prior Service Cost			
From Regulatory Asset	205	205	206
From Other Comprehensive Income[1]	5	5	5
Amortization of Net Actuarial Loss			
From Regulatory Asset	--	24	642
From Other Comprehensive Income[1]	--	1	17
Net Periodic Postretirement Benefit Cost	$3,465	$3,706	$5,736
Effect of Medicare Part D Subsidy	$(948)	$(1,806)	$(2,039)

[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:

	2014	2013	2012
Discount Rate	5.10%	4.25%	5.05%

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

(in thousands)	2014	2013
Regulatory Asset:		
Unrecognized Prior Service Cost	$335	$540
Unrecognized Net Actuarial Loss (Gain)	7,086	(344)
Net Regulatory Asset	$7,421	$196

Projected Benefit Obligation Liability – Net Amount Recognized	$(53,638)	$(45,221)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	$13	$18
Unrecognized Net Actuarial Gain	(209)	(261)
Accumulated Other Comprehensive Gain	$(196)	$(243)

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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, 2014:

(in thousands)	2014	2013
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Company Contributions	2,320	2,012
Benefit Payments (Net of Medicare Part D Subsidy)	(5,017)	(4,626)
Participant Premium Payments	2,697	2,614
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$45,221	$58,883
Service Cost (Net of Medicare Part D Subsidy)	1,055	1,421
Interest Cost (Net of Medicare Part D Subsidy)	2,200	2,050
Benefit Payments (Net of Medicare Part D Subsidy)	(5,017)	(4,626)
Participant Premium Payments	2,697	2,614
Actuarial Loss (Gain)	7,482	(15,121)
Projected Benefit Obligation at December 31	$53,638	$45,221
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$(45,268)	$(43,574)
Expense	(3,465)	(3,706)
Net Company Contribution	2,320	2,012
Accrued Postretirement Cost at December 31	$(46,413)	$(45,268)

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

	2014	2013
Discount Rate	4.20%	5.10%

Assumed healthcare cost-trend rates as of December 31:

	2014	2013
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.32 %	6.47 %
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.63 %	6.82 %
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00 %	5.00 %
Year the Rate Reaches the Ultimate Trend Rate	2025	2025

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 2014 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 7,442	$ (6,088)
Effect on Total of Service and Interest Cost	$ 516	$ (414)
Effect on Expense	$ 516	$ (606)

Measurement Dates:	2014	2013

Net Periodic Postretirement Benefit Cost	January 1, 2014	January 1, 2013
End of Year Benefit Obligations	January 1, 2014 projected to December 31, 2014	January 1, 2013 projected to December 31, 2013

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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 2015 are:

(in thousands)	2015
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$205
Amortization of Unrecognized Actuarial Loss	191
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Loss	5
Total Estimated Amortization	$406

Cash flows—The Company expects to contribute $2.6 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2015. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $456,000 in 2015. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2015	2016	2017	2018	2019	Years 2020-2024
	$2,638	$2,762	$2,925	$3,086	$3,247	$ 17,281

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 $3,171,000 for 2014, $2,748,000 for 2013 and $2,283,000 for 2012.

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 $696,000 for 2014, $705,000 for 2013 and $735,000 for 2012.

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:

Cash and Short Term Investments—The carrying amount approximates fair value because of the short term maturity of those instruments.

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of December 31, 2014 and December 31, 2013 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%, respectively, 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 Company’s long-term debt subject to variable interest rates approximates fair value. 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, 2014		December 31, 2013	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$--	$--	$2,007	$2,007
Short Term Debt	(10,854)	(10,854)	(51,195)	(51,195)
Long Term Debt including Current Maturities	(498,690)	(600,828)	(389,777)	(427,796)

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13. Property, Plant and Equipment

(in thousands)	December 31, 2014	December 31, 2013
Electric Plant in Service		
Production	$690,024	$679,067
Transmission	323,496	270,606
Distribution	438,489	421,803
General	93,103	89,408
Electric Plant in Service	1,545,112	1,460,884
Construction Work in Progress	240,170	184,780
Total Gross Electric Plant	1,785,282	1,645,664
Less Accumulated Depreciation and Amortization	584,956	554,818
Net Electric Plant	$1,200,326	$1,090,846
Nonelectric Operations Plant		
Equipment	$135,007	$131,075
Buildings and Leasehold Improvements	36,558	36,420
Land	3,594	3,430
Nonelectric Operations Plant	175,159	170,925
Construction Work in Progress	8,507	2,682
Total Gross Nonelectric Plant	183,666	173,607
Less Accumulated Depreciation and Amortization	115,462	108,763
Net Nonelectric Operations Plant	$68,204	$64,844
Net Plant	$1,268,530	$1,155,690

The estimated service lives for rate-regulated properties is 5 to 70 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

(years)	Service Life Range Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	70
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 2014, 2013 and 2012) to net income before total income tax expense for the following reasons:

(in thousands)	2014	2013	2012
Tax Computed at Federal Statutory Rate – Continuing Operations	$25,704	$21,389	$18,622
Increases (Decreases) in Tax from:			
Federal PTCs	(7,517)	(6,612)	(6,695)
State Income Taxes Net of Federal Income Tax Expense (Benefit)	1,993	1,561	(249)
Section 199 Domestic Production Activities Deduction	(1,026)	--	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(849)	(863)	(891)
Dividend Received/Paid Deduction	(622)	(632)	(656)
Investment Tax Credit Amortization	(597)	(597)	(720)
Allowance for Funds Used During Construction - Equity	(505)	(638)	(409)
Corporate Owned Life Insurance	(354)	(856)	(585)
Tax Depreciation - Treasury Grant for Wind Farms	(152)	(304)	(304)
Differences Reversing in Excess of Federal Rates	(106)	(100)	(143)
Impact of Medicare Part D Change	--	--	(584)
Permanent and Other Differences	588	168	(213)
Total Income Tax Expense – Continuing Operations	$16,557	$12,516	$7,173
Income Tax Expense (Benefit) – Discontinued Operations – U.S.	3,952	1,042	(19,707)
Income Tax Expense (Benefit) – Continuing and Discontinued Operations	$20,509	$13,558	$(12,534)
Overall Effective Federal, State and Foreign Income Tax Rate	26.2 %	21.0 %	70.4 %
Income Tax Expense From Continuing Operations Includes the Following:			
Current Federal Income Taxes	$124	$146	$(3,198)
Current State Income Taxes	5	37	(361)
Deferred Federal Income Taxes	21,044	17,488	15,877
Deferred State Income Taxes	4,347	2,917	3,161
Federal PTCs	(7,517)	(6,612)	(6,695)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(849)	(863)	(891)
Investment Tax Credit Amortization	(597)	(597)	(720)
Total	$16,557	$12,516	$7,173
Income (Loss) Before Income Taxes – U.S.	$78,232	$63,924	$(13,426)
Income (Loss) Before Income Taxes – Foreign (Discontinued Operations)	--	499	(4,381)
Total Income (Loss) Before Income Taxes – Continuing and Discontinued Operations	$78,232	$64,423	$(17,807)

The Company’s deferred tax assets and liabilities were composed of the following on December 31:

(in thousands)	2014	2013
Deferred Tax Assets		
Retirement Benefits Liabilities	$42,706	$39,524
Benefit Liabilities	42,479	39,480
North Dakota Wind Tax Credits	41,783	42,241
Federal PTCs	30,189	33,620
Cost of Removal	29,089	27,926

Differences Related to Property	10,505	9,462
Net Operating Loss Carryforward	7,842	15,151
Vacation Accrual	2,154	1,843
Investment Tax Credits	1,549	1,960
Other	1,915	4,045
Total Deferred Tax Assets	$210,211	$215,252
Deferred Tax Liabilities		
Differences Related to Property	$(313,959)	$(302,852)
Retirement Benefits Regulatory Asset	(42,706)	(39,524)
Excess Tax over Book Pension	(12,928)	(6,977)
North Dakota Wind Tax Credits	(11,543)	(11,543)
Impact of State Net Operating Losses on Federal Taxes	(2,745)	(3,088)
Regulatory Asset	(2,087)	(1,805)
Other	(5,571)	(6,360)
Total Deferred Tax Liabilities	$(391,539)	$(372,149)
Deferred Income Taxes	$(181,328)	$(156,897)

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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 13.8% in 2014 compared with 2013. 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, 2014:

(in thousands)	Amount	2015	2016	2017	2024-33
United States					
Federal Tax Credits	$31,913	$--	$--	$--	$31,913
State Net Operating Losses	5,829	--	--	--	5,829
State Tax Credits	38,654	2,339	2,339	389	33,587

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 $5.1 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)	2014	2013	2012
Balance on January 1	$4,239	$4,436	$12,138
Increases Related to Tax Positions for Prior Years	120	98	--
Decreases Related to Tax Positions for Prior Years	(4,142)	(295)	(6,802)
Increases Related to Tax Positions for Current Year	5	--	--
Uncertain Positions Resolved During Year	--	--	(900)
Balance on December 31	$222	$4,239	$4,436

The balance of unrecognized tax benefits as of December 31, 2014 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2014 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, 2014.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2014, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2011. On September 13, 2013 the IRS and U.S. Treasury issued final regulations on the deductibility and capitalization of expenditures related to tangible property, generally effective for tax years beginning on or after January 1, 2014. Taxpayers were allowed to elect early adoption of the regulations for the 2012 or 2013 tax year. Deferred tax liabilities at December 31, 2014 are not materially affected by the regulations. The final regulations do not impact the effect of Revenue Procedure 2013-24 issued on April 30, 2013, which provided guidance for repairs related to generation property. Among other things, the Revenue Procedure listed units of property and material components of units of property for purposes of analyzing repair versus capitalization issues. The Company will adopt Revenue Procedure 2013-24 and the final tangible property regulations for income tax filings for tax year 2014.

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.

OTP recorded no new AROs in 2014.

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, 2014 and 2013 are presented in the following table:

(in thousands)	2014	2013
Asset Retirement Obligations		
Beginning Balance	$5,661	$5,207
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	1,582	--
Accrued Accretion	478	454
Settlements	--	--
Ending Balance	$7,721	$5,661
Asset Retirement Costs Capitalized		
Beginning Balance	$1,477	$1,477
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	1,582	--
Settlements	--	--
Ending Balance	$3,059	$1,477
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$462	$407
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	65	55
Settlements	--	--
Ending Balance	$527	$462
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 December 31, 2014 the Company was in the process of negotiating the sales of Foley and Aevenia, our Construction segment subsidiaries. The Company has entered into signed letters of intent to sell Aevenia and Foley and expects to close on the respective transactions by the end of the first quarter of 2015. These companies' assets met the criteria to be classified as held for sale on December 31, 2014 and, as such, the companies are being reported as discontinued operations as of December 31, 2014.

On February 8, 2013 the Company sold substantially all the assets of Shrco, formerly included in the Company's Manufacturing segment, for approximately $13.0 million in cash and received a working capital true-up of approximately $2.4 million in June 2013. On January 18, 2012 the Company sold the assets of Aviva, a subsidiary of Shrco, for $0.3 million in cash. For discontinued operations reporting, Aviva's results are included in Shrco's consolidated results.

On November 30, 2012 the Company completed the sale of the assets of IMD for total proceeds, net of commissions and selling costs, of $18.1 million. Prior to the sale, IMD was the only remaining entity in the Company's former Wind

Energy segment.

On February 29, 2012 the Company completed the sale of DMS, its health services company, for $24.0 million in cash net of commissions and selling costs, which was reduced by a $1.7 million working capital settlement paid to the buyer in February 2013. The DMS working capital settlement was estimated to be $1.9 million at the time of the sale. The final settlement resulted in the Company recording a $0.2 million gain on the sale of DMS in the first quarter of 2013. DMS was the only business in the Company's former Health Services segment.

On December 29, 2011 the Company completed the sale of Wylie for approximately $25.0 million in cash. Wylie and IMD made up the Company's former Wind Energy segment.

On May 6, 2011 the Company completed the sale of IPH for approximately $86.0 million in cash. IPH was the only business in the Company's former Food Ingredient Processing segment.

The Company's Wind Energy, Health Services, Food Ingredient Processing and Construction segments were eliminated as a result of the sales of IMD, DMS and IPH and the classifications of Foley and Aevenia as discontinued operations. The financial position, results of operations, and cash flows of Foley, Aevenia, IMD, Wylie, Shrco, DMS and IPH 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, 2014, 2013 and 2012 and major components of assets and liabilities of discontinued operations as of December 31, 2014 and 2013:

For the Year Ended December 31, 2014

(in thousands)	Foley	Aevenia	IMD	Shrco	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

For the Year Ended December 31, 2013

(in thousands)	Foley	Aevenia	IMD	Wylie	Shrco	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$110,097	$39,813	$--	$--	$2,016	$--	$ (11)	$151,915
Operating Expenses	109,036	38,257	(988)	640	2,622	(269)	(11)	149,287
Interest Expense	249	207	--	--	--	--	(452)	4
Other Income (Deductions)	4	(5)	412	--	67	--	(5)	473
Income Tax Expense (Benefit)	331	518	370	(256)	(213)	108	179	1,037
Net Income (Loss) from Operations	485	826	1,030	(384)	(326)	161	268	2,060
Gain on Disposition Before Taxes	--	--	--	--	16	200	--	216
Income Tax Expense on Disposition	--	--	--	--	6	--	--	6
Net Gain on Disposition	--	--	--	--	10	200	--	210
Net Income (Loss)	$485	$826	$1,030	$(384)	$(316)	$361	$ 268	$2,270

For the Year Ended December 31, 2012

(in thousands)	Foley	Aevenia	IMD	Wylie	Shrco	DMS	IPH	Intercompany Transactions Adjustment	Total
Operating Revenues	$93,598	$55,494	$186,151	$--	$32,563	$16,362	$--	$ (2,032)	$382,136
Operating Expenses	109,493	51,873	184,462	179	36,163	14,741	--	(2,032)	394,879
Asset Impairment Charge	--	--	45,573	--	7,747	--	--	--	53,320
Interest Expense	689	351	5,787	--	1,553	279	--	(8,482)	177

Other Income	--	169	135	--	15	122	--	--	441
Income Tax (Benefit) Expense	(6,630)	1,174	(15,792)	13	(4,021)	1,734	106	3,393	(20,023)
Net (Loss) Income from Operations	(9,954)	2,265	(33,744)	(192)	(8,864)	(270)	(106)	5,089	(45,776)
Loss on Disposition Before Taxes	--	--	--	(62)	--	(5,154)	--	--	(5,216)
Income Tax Expense (Benefit) on Disposition	--	--	--	460	--	(145)	--	--	315
Net Loss on Disposition	--	--	--	(522)	--	(5,009)	--	--	(5,531)
Net (Loss) Income	$(9,954)	$2,265	$(33,744)	$(714)	$(8,864)	$(5,279)	$(106)	$ 5,089	$(51,307)

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	December 31, 2014				
(in thousands)	Foley	Aevenia	IMD	Shrco	Total
Current Assets	$29,897	$5,277	$--	$--	$35,174
Goodwill and Intangibles	2,814	--	--	--	2,814
Net Plant	4,445	6,224	--	--	10,669
Assets of Discontinued Operations	$37,156	$11,501	$--	$--	$48,657
Current Liabilities	$17,114	$2,916	$1,840	$994	$22,864
Deferred Income Taxes	2,065	2,630	--	--	4,695
Liabilities of Discontinued Operations	$19,179	$5,546	$1,840	$994	$27,559

	December 31, 2013				
(in thousands)	Foley	Aevenia	IMD	Shrco	Total
Current Assets	$21,408	$8,123	$--	$38	$29,569
Goodwill and Intangibles	8,420	163	--	--	8,583
Net Plant	5,225	6,101	--	--	11,326
Assets of Discontinued Operations	$35,053	$14,387	$--	$38	$49,478
Current Liabilities	$29,766	$2,499	$2,196	$1,441	$35,902
Deferred Income Taxes	1,892	1,489	--	--	3,381
Liabilities of Discontinued Operations	$31,658	$3,988	$2,196	$1,441	$39,283

Included in current liabilities of discontinued operations are warranty reserves. Details regarding the warranty reserves follow:

(in thousands)	2014	2013
Warranty Reserve Balance, Beginning of Year	$3,087	$5,027
Provision for Warranties Issued During the Year	--	188
Less Settlements Made During the Year	(372)	(715)
Decrease in Warranty Estimates for Prior Years	(188)	(1,413)
Warranty Reserve Balance, End of Year	$2,527	$3,087

The warranty reserve balances as of December 31, 2014 and December 31, 2013 relate entirely to products produced by the Company’s former wind tower and waterfront equipment manufacturing companies. Expenses associated with remediation activities of these companies could be substantial. 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. 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 results of operations and financial condition.

Commitments under operating lease obligations for Foley and Aevenia totaled $1.9 million on December 31, 2014.
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17. Subsequent Events

<u>Stock Incentive Awards</u>
On February 6, 2015 the Company's board of directors granted the following stock incentive awards to the Company's executive officers under the 2014 Stock Incentive Plan:

Award	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Restricted Stock Units Granted to Executive Officers	20,900	$ 31.675	25% per year through February 6, 2019
Restricted Stock Units Granted to Executive Officer	6,400	$ 31.675	100% on February 6, 2020
Stock Performance Awards Granted to Executive Officers	77,500	$ 26.99	December 31, 2017

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement or, 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 77,500 shares. For target performance the Company's executive officers would earn an aggregate of 51,667 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance measurement period of January 1, 2015 through December 31, 2017, 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, 2015 and the average closing price for the 20 trading days immediately preceding January 1, 2018. The Company's executive officers would also earn an aggregate of 25,833 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 116,250 common shares. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. The terms of these awards are such that the entire award will be classified and accounted for as a liability, as required under ASC 718, and will be 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.

Under the 2015 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.

<u>Sale of Aevenia</u>

On February 24, 2015 the Company entered into an agreement to sell Aevenia for $25 million in cash plus adjustments for working capital and final assets to be determined within 90 days of closing. The sale of Aevenia is subject to certain closing conditions and is expected to close by February 28, 2015.

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. Amounts shown below will differ from amounts disclosed in previously filed quarterly reports on Forms 10-Q as a result of the classifications of Foley and Aevenia as discontinued operations in the fourth quarter of 2014. See note 16 to consolidated financial statements for more details.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2014	2013	2014	2013	2014	2013	2014[1]	2013
Operating Revenues								
Previously Reported	$240,472	$217,954	$234,611	$212,389	242,371	$229,768	$--	$233,202
Less: Operating Revenues–Foley and Aevenia	25,506	26,413	40,247	34,996	45,846	47,511	--	40,979
Operating Revenues–Continuing Operations	$214,966	$191,541	$194,364	$177,393	$196,525	$182,257	$193,407	$192,223
Operating Income								
Previously Reported	$34,422	$27,239	$18,239	$15,779	$28,322	$25,132	$--	$28,701
Less: Operating (Loss) Income–Foley and Aevenia	(979)	(1,699)	3,487	150	3,800	3,102	--	1,061
Operating Income–Continuing Operations	$35,401	$28,938	$14,752	$15,629	$24,522	$22,030	$24,856	$27,640
Net Income (Loss):								
Continuing Operations Previously Reported	$21,362	$15,234	$9,984	$7,504	$15,653	$14,826	$--	$12,610
Less: Net (Loss) Income–Foley and Aevenia	(417)	(1,028)	2,098	89	2,481	1,857	--	661
Continuing Operations	$21,779	$16,262	$7,886	$7,415	$13,172	$12,969	$14,046	$11,949
Discontinued Operations Previously Reported	$68	$129	$9	$197	$172	$312	$--	$53
Plus: Net (Loss) Income–Foley and Aevenia	(417)	(1,028)	2,098	89	2,481	1,857	--	661
Discontinued Operations	$(349)	$(899)	$2,107	$286	$2,653	$2,169	$(3,571)	$714
Total	$21,430	$15,363	$9,993	$7,701	$15,825	$15,138	$10,475	$12,663
Earnings (Loss) Available for Common Shares:								
	$21,362	$14,721	$9,984	$7,504	$15,653	$14,826	$--	$12,610

Continuing Operations Previously Reported								
Less: (Loss) Earnings–Foley and Aevenia	(417)	(1,028)	2,098	89	2,481	1,857	--	661
Continuing Operations	$21,779	$15,749	$7,886	$7,415	$13,172	$12,969	$14,046	$11,949
Discontinued Operations Previously Reported	$68	$129	$9	$197	$172	$312	$--	$53
Plus: (Loss) Earnings–Foley and Aevenia	(417)	(1,028)	2,098	89	2,481	1,857	--	661
Discontinued Operations	$(349)	$(899)	$2,107	$286	$2,653	$2,169	$(3,571)	$714
Total	$21,430	$14,850	$9,993	$7,701	$15,825	$15,138	$10,475	$12,663
Basic Earnings (Loss) Per Share:								
Continuing Operations Previously Reported	$.59	$.41	$.27	$.21	$.43	$.41	$--	$.35
Less: (Loss) Earnings–Foley and Aevenia	(.01)	(.03)	.06	.01	.07	.05	--	.02
Continuing Operations	$.60	$.44	$.21	$.20	$.36	$.36	$.38	$.33
Discontinued Operations Previously Reported	$--	$--	$--	$--	$--	$.01	$--	$--
Plus: (Loss) Earnings–Foley and Aevenia	(.01)	(.03)	.06	.01	.07	.05	--	.02
Discontinued Operations	$(.01)	$(.03)	$.06	$.01	$.07	$.06	$(.10)	$.02
Total	$.59	$.41	$.27	$.21	$.43	$.42	$.28	$.35
Diluted Earnings (Loss) Per Share:								
Continuing Operations Previously Reported	$.59	$.41	$.27	$.21	$.43	$.41	$--	$.35
Less: (Loss) Earnings–Foley and Aevenia	(.01)	(.02)	.06	.01	.07	.05	--	.02
Continuing Operations	$.60	$.43	$.21	$.20	$.36	$.36	$.38	$.33
Discontinued Operations Previously Reported	$--	$--	$--	$--	$--	$.01	$--	$--
Plus: (Loss) Earnings–Foley and Aevenia	(.01)	(.02)	.06	.01	.07	.05	--	.02
Discontinued Operations	$(.01)	$(.02)	$.06	$.01	$.07	$.06	$(.10)	$.02
Total	$.59	$.41	$.27	$.21	$.43	$.42	$.28	$.35
Dividends Declared Per Common Share	$.3025	$.2975	$.3025	$.2975	$.3025	$.2975	$.3025	$.2975
Price Range:								
High	31.72	31.34	31.08	31.70	30.43	31.88	32.72	30.95
Low	26.96	25.17	27.19	26.50	26.67	25.84	26.53	26.80

Average Number of Common Shares Outstanding--Basic	36,240	36,075	36,410	36,170	36,596	36,180	36,811	36,180
Average Number of Common Shares Outstanding--Diluted	36,432	36,259	36,653	36,374	36,839	36,382	37,049	36,384

[1] Results include pre-tax goodwill impairment charge of $5.6 million at Foley in discontinued operations.
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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, 2014, 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, 2014.

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, 2014 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, 2014. 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, 2014, 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 62.

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 2015 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 2015 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 2015 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 2015 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 2015 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 “Outstanding Voting Shares” and “Security Ownership of Directors and Officers” in the Company’s definitive Proxy Statement for the 2015 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2014 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	172,947	(1)	$ 0.00	1,685,653	(2)
1999 Stock Incentive Plan	265,825	(3)	$ 1.20	--	(4)
1999 Employee Stock Purchase Plan	--		N/A	460,294	(5)
Equity compensation plans not approved by security holders	--		--	--	
Total	438,772		$ 0.72	2,145,947	

(1) Includes 159,450 performance based share awards granted in 2014, 11,250 restricted stock units outstanding as of December 31, 2014, and 2,247 stock units as part of the director deferred compensation program, and excludes 38,675 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, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights.

(3) Includes 90,600 and 89,991 performance based share awards granted in 2013 and 2012, respectively, 34,650 restricted stock units outstanding as of December 31, 2014, and 37,834 stock units as part of the director deferred compensation program and 12,750 outstanding options as of December 31, 2014, and excludes 44,655 shares of restricted stock issued under the 1999 Stock Incentive Plan.

(4) The 1999 Stock Incentive Plan provides for the issuance of any shares available under the plan in the form of restricted stock, 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 2015 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 2015 Annual Meeting.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of documents filed as part of this report:

1. Financial Statements

2. Financial Statement Schedules

SCHEDULE 1 - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Balance Sheets, December 31

(in thousands)	2014	2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$--	$7,907
Accounts Receivable from Subsidiaries	4,651	1,736
Interest Receivable from Subsidiaries	191	192
Notes Receivable from Subsidiaries	13,553	5,703
Deferred Income Taxes	13,895	28,853
Other	1,105	947
Total Current Assets	33,395	45,338
Investments in Subsidiaries	605,242	541,291
Notes Receivable from Subsidiaries	52,060	52,249
Deferred Income Taxes	36,632	25,861
Other Assets	27,365	25,456
Total Assets	$754,694	$690,195
LIABILITIES AND EQUITY		
Current Liabilities		

Accounts Payable to Subsidiaries	$5,990	$5,961
Notes Payable to Subsidiaries	67,218	62,562
Other	18,371	5,122
Total Current Liabilities	91,579	73,645
Other Noncurrent Liabilities	36,860	28,031
Commitments and Contingencies		
Capitalization		
Long-Term Debt, Net of Current Maturities	53,489	53,689
Common Shareholder Equity	572,766	534,830
Total Capitalization	626,255	588,519
Total Liabilities and Equity	$754,694	$690,195

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Statements of Income--For the Years Ended December 31

(in thousands)	2014	2013	2012
Operating Loss			
Revenue	$--	$--	$--
Operating Expenses	12,593	14,150	15,197
Operating Loss	(12,593)	(14,150)	(15,197)
Other Income (Expense)			
Equity Income in Earnings of Subsidiaries	64,926	66,468	8,430
Loss on Early Retirement of Debt	--	(10,252)	(13,106)
Interest Charges	(6,326)	(9,940)	(13,994)
Interest Charges to Subsidiaries	(117)	(494)	(512)
Interest Income from Subsidiaries	4,980	5,318	15,700
Other Income	1,379	1,413	1,426
Total Other Income (Expense)	64,842	52,513	(2,056)
Income Before Income Taxes – Continuing Operations	52,249	38,363	(17,253)
Income Tax Benefit	(5,474)	(12,502)	(11,980)
Net Income (Loss) from Continuing Operations	57,723	50,865	(5,273)
Net Income (Loss) from Discontinued Operations	--	--	--
Total Net Income (Loss)	57,723	50,865	(5,273)
Preferred Dividend Requirement and Other Adjustments	--	513	736
Income (Loss) Available for Common Shares	$57,723	$50,352	$(6,009)

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)	**2014**	2013	2012
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	**$47,697**	$70,376	$43,904
Cash Flows from Investing Activities			
(Investment in Subsidiaries) Return of Capital	**(44,000)**	150,381	(137,726)
Debt (Issued to) Repaid by Subsidiaries	**(7,662)**	(141,919)	239,452
Cash Used in Investing Activities	**(44)**	(37)	(69)
Net Cash (Used in) Provided by Investing Activities	**(51,706)**	8,425	101,657
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**215**	-	-
Net Short-Term Borrowings	**10,854**	-	-
Borrowings from Subsidiaries	**4,656**	-	-
Proceeds from Issuance of Common Stock	**26,259**	1,821	-
Common Stock Issuance Expenses	**(673)**	(3)	(370)
Payments for Retirement of Capital Stock	**(590)**	(15,723)	(111)
Short-Term and Long-Term Debt Issuance Expenses	**(170)**	(238)	(700)
Payments for Retirement of Long-Term Debt	**(188)**	(47,846)	(50,164)

Premium Paid for Early Retirement of Long-Term Debt	**--**	(9,889)	(12,500)
Dividends Paid and Other Distributions	**(44,261)**	(43,818)	(43,976)
Net Cash Used in Financing Activities	**(3,898)**	(115,696)	(107,821)
Net Change in Cash and Cash Equivalents	**(7,907)**	(36,895)	37,740
Cash and Cash Equivalents at Beginning of Period	**7,907**	44,802	7,062
Cash and Cash Equivalents at End of Period	**$--**	$7,907	$44,802

See accompanying notes to condensed financial statements.

Otter Tail Corporation (Parent Company)
Notes to Condensed Financial Statements
For the years ended December 31, 2014, 2013 and 2012

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, 2014:

(in thousands)	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 3,599	$ --	$ --	$ --	$ 42	$--
Vinyltech Corporation	2	32	--	8,500	--	13,995
Northern Pipe Products, Inc.	--	8	--	3,360	--	9,233
BTD Manufacturing, Inc.	33	107	--	28,500	--	55
IMD, Inc.	--	--	1,602	--	--	--
Shrco, Inc.	--	--	--	--	--	378
T.O. Plastics, Inc.	--	28	--	7,400	--	6,477
Aevenia, Inc.	86	7	--	1,800	--	--
Foley Company	35	9	11,951	2,500	--	6,004
Varistar Corporation	816	--	--	--	5,948	31,076
Otter Tail Assurance Limited	80	--	--	--	--	--
	$ 4,651	$ 191	$ 13,553	$ 52,060	$ 5,990	$67,218

As of December 31, 2013:

(in thousands)	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 1,346	$ --	$ --	$ --	$ 11	$--
Vinyltech Corporation	--	32	--	8,500	--	17,285
Northern Pipe Products, Inc.	--	9	--	3,549	--	11,948

BTD Manufacturing, Inc.	7	107	--	28,500	--	3,985
IMD, Inc.	--	--	1,266	--	--	--
Shrco, Inc.	2	--	3,889	--	--	--
T.O. Plastics, Inc.	--	28	--	7,400	1	4,705
Aevenia, Inc.	--	7	548	1,800	1	--
Foley Company	44	9	--	2,500	--	5,343
Varistar Corporation	--	--	--	--	5,948	19,296
Otter Tail Assurance Limited	337	--	--	--	--	--
	$ 1,736	$ 192	$ 5,703	$ 52,249	$ 5,961	$62,562

Dividends

Dividends paid to Otter Tail Corporation (the Parent) from its subsidiaries were as follows:

(in thousands)	2014	2013	2012
Cash Dividends Paid to Parent by Subsidiaries	$44,261	$91,693	$43,018

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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.

	File No.	Previously Filed 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.
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-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.

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	File No.	Previously Filed As Exhibit No.	
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-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 11/18/97	4-D-11	—Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 between the registrant and U.S. Bank National Association (formerly First Trust National Association), as Trustee.
4-F-1	8-K filed 7/1/09	4.1	—First Supplemental Indenture, dated as of July 1, 2009, to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997.
4-F-2	8-K filed 12/4/09	4.1	—Officer’s Certificate and Authentication Order, dated December 4, 2009, for the 9.000% Notes due 2016 (which includes the form of Note) issued pursuant to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 and the First Supplemental Indenture thereto, dated as of July 1, 2009.
4-G	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.
10 A	2 39794	4 C	—Integrated Transmission Agreement, dated August 25, 1967, between Cooperative Power Association and the Company.
10 A 1	10 K for year ended 12/31/92	10 A 1	—Amendment No. 1, dated as of September 6, 1979, to Integrated Transmission Agreement, dated as of August 25, 1967, between Cooperative Power Association and the Company.
10 A 2	10 K for year ended 12/31/92	10 A 2	—Amendment No. 2, dated as of November 19, 1986, to Integrated Transmission Agreement between Cooperative Power Association and the Company.
10 C 1	2 55813	5 E	—Contract dated July 1, 1958, between Central Power Electric Corporation, Inc., and the Company.
10 C 2	2 55813	5 E 1	—Supplement Seven dated November 21, 1973. (Supplements Nos. One through Six have been superseded and are no longer in effect.)
10 C 3	2 55813	5 E 2	—Amendment No. 1 dated December 19, 1973, to Supplement Seven.
10 C 4	10 K for year ended 12/31/91	10 C 4	—Amendment No. 2 dated June 17, 1986, to Supplement Seven.

10-C-5	10-K for year ended 12/31/92	10-C-5	—Amendment No. 3 dated June 18, 1992, to Supplement Seven.
10-C-6	10-K for year ended 12/31/93	10-C-6	—Amendment No. 4 dated January 18, 1994 to Supplement Seven.
10-D	2-55813	5-F	—Contract dated April 12, 1973, between the Bureau of Reclamation and the Company.

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	File No.	Previously Filed As Exhibit No.	
10 E 1	2 55813	5 G	—Contract dated January 8, 1973, between East River Electric Power Cooperative and the Company.
10 E 2	2 62815	5 E 1	—Supplement One dated February 20, 1978.
10 E 3	10 K for year ended 12/31/89	10 E 3	—Supplement Two dated June 10, 1983.
10 E 4	10 K for year ended 12/31/90	10 E 4	—Supplement Three dated June 6, 1985.
10 E 5	10 K for year ended 12/31/92	10 E 5	—Supplement No. Four, dated as of September 10, 1986.
10 E 6	10 K for year ended 12/31/92	10 E 6	—Supplement No. Five, dated as of January 7, 1993.
10 E 7	10 K for year ended 12/31/93	10 E 7	—Supplement No. Six, dated as of December 2, 1993.
10 F	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 F 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 F 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 F 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 F 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-F-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 F 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 G	10-Q for quarter ended 6/30/04	10.3	—Master Coal Purchase and Sale Agreement by and between the Company, Montana-Dakota Utilities Co., Northwestern Corporation and Kennecott Coal Sales Company-Big Stone Plant (dated as of June 1, 2004).
10 H	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 H 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 H 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 H 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 H 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 H 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.

	File No.	Previously Filed As Exhibit No.	
10-H-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 I	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 I 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 I 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 I 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 I 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-I-5	10-K for year ended 12/31/01	10-I-5	—Agreement and Consent to Assignment of the Coyote Plant Coal Agreement.
10-J	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-J-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 K	10 K for year ended 12/31/91	10 L	—Integrated Transmission Agreement by and between the Company, Missouri Basin Municipal Power Agency and Western Minnesota Municipal Power Agency (dated as of March 31, 1986).
10 K 1	10 K for year ended 12/31/88	10 L 1	—Amendment No. 1, dated as of December 28, 1988, to Integrated Transmission Agreement (dated as of March 31, 1986).
10 L	10-Q for quarter ended 6/30/04	10.1	—Master Coal Purchase Agreement by and between the Company and Kennecott Coal Sales Company - Hoot Lake Plant (dated as of December 31, 2001).
10 M	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-N	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 O 1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended.*
10-O-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-O-1b	8-K filed 4/17/14	10.5	—Second Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10 O 2	8-K filed 2/04/05	10.1	—Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10 O 2a	10 K for year ended 12/31/06	10-N-2a	—First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*

	File No.	Previously Filed As Exhibit No.	
10-O-2b	10-K for year ended 12/31/10	10-N-2B	—Second Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10 O 3			—Nonqualified Profit Sharing Plan.*
10 O 4	10 Q for quarter ended 3/31/02	10-B	—Nonqualified Retirement Savings Plan, as amended.*
10-O-5	10-Q for quarter ended 9/30/11	10.1	—Nonqualified Retirement Plan (2011 Restatement).*
10-O-6	10-Q for quarter ended 6/30/12	10.6	—Otter Tail Corporation Executive Restoration Plus Plan.
10-O-7	8-K filed 4/19/12	10.1	—1999 Employee Stock Purchase Plan, As Amended (2012).
10-O-8	8-K filed 4/13/06	10.4	—1999 Stock Incentive Plan, As Amended (2006).
10-O-9	10-K for year ended 12/31/05	10-N-7	—Form of Stock Option Agreement.*
10-O-10	8-K filed 4/19/12	10.2	—Form of 2012 Restricted Stock Award Agreement for Executive Officers.*
10-O-11	8-K filed 4/19/12	10.3	—Form of 2012 Performance Award Agreement.*
10-O-12	10-K for year ended 12/31/11	10-N-11	—Executive Annual Incentive Plan.*
10-O-13	8-K filed 4/19/12	10.4	—Form of 2012 Restricted Stock Unit Award Agreement.*
10-O-14	8-K filed 4/13/06	10.1	—Form of 2012 Restricted Stock Award Agreement for Directors.*
10-O-15	10-K for year ended 12/31/13	10-O-12	—2014 Executive Annual Incentive Plan.*
10-O-16	333-195337	4.1	—Otter Tail Corporation 2014 Stock Incentive Plan.
10-O-17	8-K filed 4/17/14	10.1	—Form of 2014 Performance Award Agreement.*
10-O-18	8-K filed 4/17/14	10.2	—Form of 2014 Restricted Stock Award Agreement for Executive Officers.*
10-O-19	8-K filed 4/17/14	10.3	—Form of 2014 Restricted Stock Award Agreement for Directors.*
10-O-20	8-K filed 4/17/14	10.4	—Summary of Non-Employee Director Compensation.
10-O-21	8-K filed 5/14/14	10.1	—Separation Agreement and General Release dated May 8, 2014 between Otter Tail Corporation and Mr. Waslaski.
10-O-22	8-K filed 9/26/14	10.1	—Amendment to 2014 Performance Award Agreement with Edward J. McIntyre.*
10-O-23	8-K filed 9/26/14	10.2	—Amendment to 2013 Performance Award Agreement with Edward J. McIntyre.*
10-P	8-K filed 5/14/12	1.1	—Distribution Agreement dated May 14, 2012, between Otter Tail Corporation and J.P. Morgan Securities LLC.
10-Q-1	10-K for year ended 12/31/12	10-O-1	—Executive Employment Agreement, Kevin Moug.*
10-Q-2	10-K for year ended 12/31/12	10-O-2	—Executive Employment Agreement, George Koeck.*
10-Q-3	10-K for year ended 12/31/12	10-O-3	—Executive Employment Agreement, Chuck MacFarlane.*
10-Q-4		10-O-4	—Executive Employment Agreement, Shane Waslaski.*

	10-K for year ended 12/31/12		
10-Q-5	10-Q for quarter ended 9/30/14	10.5	—Executive Employment Agreement, Paul Knutson.*
10-R-1	10-K for year ended 12/31/10	10-Q-3	—Change in Control Severance Agreement, Kevin G. Moug.*

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	File No.	Previously Filed As Exhibit No.	
10-R-2	10-K for year ended 12/31/10	10-Q-4	—Change in Control Severance Agreement, George Koeck.*
10-R-3	10-K for year ended 12/31/11	10-Q-5	—Change in Control Severance Agreement, Chuck MacFarlane.*
10-R-4	10-K for year ended 12/31/11	10-Q-6	—Change in Control Severance Agreement, Shane Waslaski.*
10-R-5	10-K for year ended 12/31/11	10-Q-7	—Change in Control Severance Agreement, Edward J. McIntyre.*
10-R-6	10-Q for quarter ended 9/30/14	10.3	—Change in Control Severance Agreement, Timothy Rogelstad.*
10-R-7	10-Q for quarter ended 9/30/14	10.6	—Change in Control Severance Agreement, Paul Knutson.*
10-S-1	10-Q for quarter ended 9/30/14	10.4	—Severance Agreement, Timothy Rogelstad.*
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, 2014, 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 Commission pursuant to a confidential treatment request under Rule 24b-2.

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.

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: March 2, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature and Title

Edward J. McIntyre	)	
Chief Executive Officer	)	
(principal executive officer) and Director	)	
	)	
Kevin G. Moug	)	
Chief Financial Officer and Senior Vice President	)	
(principal financial and accounting officer)	)	
	)	By /s/ Edward J. McIntyre
Nathan I. Partain	)	Edward J. McIntyre
Chairman of the Board and Director	)	Pro Se and Attorney-in-Fact
	)	Dated March 2, 2015
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	)	