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

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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:

Rates	Regulation	2014 % of Electric Revenues	2014 % of kwh Sales	2013 % of Electric Revenues	2013 % 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.

Transmission Cost Recovery 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 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.

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

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.

2013 compared with 2012

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

<u>2014 compared with 2013</u>
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.

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.

2013 compared with 2012
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:
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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	--	--		